FILED
03/27/19
04:59 PM

A1903026

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026 (Filed June 29, 2017)

TESTIMONY OF BILL POWERS

April Rose Maurath Sommer
Executive Director and Lead Counsel
PROTECT OUR COMMUNITIES FOUNDATION
1547 Palos Verdes Mall #196
Walnut Creek, California 94597
Telephone: (619) 363-6790
April.Sommer@ProtectOurCommunities.org

Ellison Folk
Stephanie L. Safdi
SHUTE, MIHALY & WEINBERGER LLP
396 Hayes Street
San Francisco, California 94102
Telephone: (415) 552-7272
Facsimile: (415) 552-5816
Folk@smwlaw.com
Safdi@smwlaw.com

Attorneys for PROTECT OUR COMMUNITIES FOUNDATION

Dated: April 2, 2018

TABLE OF CONTENTS

Page

I. Introduction 1

II. Background 4

A. Post Energy Crisis Power Procurement 5

B. The PCIA and its Market Price Benchmark 7

III. Actual SDG&E procurement costs are unrelated to market value costs used in the PCIA 8

IV. Brown Power Contracts Should Comprise a Diminishing Part of the PCIA 10

V. SDG&E overpaid for most of its utility-scale solar and wind PPAs 13

A. Solar project case study 13

1. Early high priced contracts approved by the Commission set an artificially inflated benchmark for utility-scale solar 13

2. TOD adders drove up contract prices even further 19

3. Low-cost RAM contracts derived from a competitive auction provide a benchmark to evaluate the imprudent component of solar PPAs 20

B. Wind Projects Case Study 22

C. The IE and PRG are inadequate safeguards to assure PPA contracts are reasonably priced 27

VI. PCIA reliance on market value of resources is flawed and should be reformed. 28

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.	R.17-06-026 (Filed June 29, 2017)

R.17-06-026

POC Foundation Opening Testimony

Bill Powers

April 2, 2018

Please state your name, place of employment, and business address.

My name is Bill Powers. I am the owner and principal of Powers Engineering, located at 4452 Park Boulevard # 209, San Diego, CA 92116

What is the purpose of this testimony?

I submit this testimony on behalf of Protect Our Communities Foundation to support its position that the PCIA must be fundamentally altered to align with the Commission's goals and principles. Currently, the PCIA is calculated by taking the difference between actual IOU portfolio costs and the market value of the portfolio, determined largely by current least-cost market prices. The PCIA should instead use the actual generation charge paid by IOU bundled customers as the benchmark to assess the above-market costs of IOU portfolios. Using San Diego Gas & Electric as a case study, this testimony demonstrates that, as currently designed and implemented, the PCIA overcharges departing load and is inconsistent with the fundament concept of price indifference.

Please describe your qualifications for providing this testimony.

I am a registered professional engineer, with extensive knowledge and experience in the fields of energy and environmental engineering, air emissions control, and regional energy planning. A copy of my resume is included as an exhibit to this testimony.

I. Introduction

The overall goal of this proceeding, as set forth in the Scoping Memo, is to ensure both that bundled customers do not experience any cost increases as a result of departing load and that departing load does not experience any cost increases as a result of allocation of costs that were

not procured on its behalf.[1] The Power Charge Indifference Adjustment ("PCIA") as currently calculated does not satisfy this objective. Rather, in practice, it permits the investor-owned utilities ("IOUs") to shed overpriced contracts for green power, brown power, and capacity resources made on behalf of all IOU customers, thereby reducing the generation charge for bundled load while passing the above-market prices for those contracts on to departing load. The consequence is that the PCIA penalizes departing load, deterring customers from joining Community Choice Aggregators ("CCAs") and other non-IOU energy providers, while benefitting bundled load, whose generation is supplied through a less expensive portfolio that better matches current market prices.

The current PCIA methodology thus benefits bundled service customers at the expense of departing load. This is contrary to Final Guiding Principle 1(i), which requires that the PCIA "reflect the value of the benefits that departing customers impart to remaining bundled service customers."[2] And it incentivizes imprudent IOU portfolio management by allowing IOUs to enter into over-priced contracts that they can later shed at the expense of departing load. This is contrary to Final Guiding Principle 1(h), which limits the PCIA to "legitimately unavoidable costs" and requires IOUs to "take all reasonable steps to minimize above-market costs."[3]

The PCIA must be fundamentally altered to align with the Commission's goals and principles. Currently, the PCIA is calculated by taking the difference between actual IOU portfolio costs and the market value of the portfolio, determined largely by current least-cost market prices. The PCIA should instead use the actual generation charge paid by IOU bundled customers as the benchmark to assess the above-market costs of IOU portfolios. Green power purchase agreement ("PPA") prices and eligible cost recovery surcharge ("CRS") brown power costs above the actual IOU generation charge benchmark would form the universe of above-market costs for which departing load customers are proportionately responsible. At the same time, the PCIA should contain a mechanism for assessing the avoidable component of above-market costs, which should be borne by IOU shareholders rather than departing load customers to satisfy the principle that the PCIA include only "legitimately unavoidable costs."

The testimony that follows develops this proposal by using San Diego Gas & Electric Company's ("SDG&E") portfolio as a case study. Part II provides background on SDG&E's post-energy crisis resource procurement and sets forth the basic parameters of the PCIA in its current guise. Part III discusses the disconnect between the actual costs of SDG&E's portfolio and the market value of those resources as determined through the PCIA's market price benchmark ("MPB") in its current iteration. Parts IV and V elaborate on the major portfolio components driving the high PCIA: CRS-eligible brown power resources (including energy and capacity charges) and solar and wind green power PPAs.

---

[1] R. 17-06-026, Scoping Memo and Ruling of Assignment Commissioner at p. 13 (Sept. 25, 2017) ("Scoping Memo").
[2] *Id.* at p. 14.
[3] *Id.*

As discussed in Part IV, brown power contracts should play a diminishing role in the PCIA. Contract costs associated with Cost Allocation Mechanism ("CAM") projects should not form part of the PCIA, as these are pass-through costs allocated to all load. CAM projects – including the 308 MW Pio Pico Energy Center and 500 MW Carlsbad Energy Center – are projects that the Commission has determined are necessary for grid reliability generally and therefore the cost must be shared by all customers, including CCA and Direct Access ("DA") customers. Of the remaining CRS-eligible brown power contrast, several substantial contracts will terminate between 2019 and 2021, at which point they can no longer be priced into the PCIA. And, as discussed below, there is a 1,267 MW gap between 2017 NQC projects SDG&E identified in its response to POC's data request and the brown power input in its 2017 PCIA calculation. This gap raises the possibility that SDG&E is putting contracts into the PCIA that are ineligible for that treatment, either because they are for CAM projects or because they are for utility-owned brown power resources that have exceeded ten years of operations.

Part V shows that SDG&E overpaid for much of its green power portfolio. Commission approval of certain high-priced solar PPAs around 2008 through an irregular process created an inflated benchmark for assessing the reasonableness of contracts. Because bids were confidential and procurement was not subject to rigorous scrutiny, there was no external check on this high priced procurement. As a consequence, the data shows that pricing of many of the green PPAs signed by SDG&E in the 2010-2012 timeframe was unjustifiably high in cost when compared with least-cost contracts SDG&E entered into during the same time period under the Renewable Auction Mechanism ("RAM"),[4] or when compared to contracts being signed by other IOUs at the same time for the same technology. Part V takes a close look at SDG&E's solar and wind contract to make this showing.

Part VI sets forth a proposal for modifying the PCIA to meet the objectives and principles set forth in the Scoping Memo. This proposal includes: (1) limiting the brown power resources in the PCIA to only those actually eligible for inclusion (2) using the actual average generation charge of IOU portfolios as the MPB to better satisfy the indifference principle at the heart of the PCIA concept, and (3) establishing a mechanism to assign the reasonably avoidable costs of green power contracts to shareholders rather than forcing departing load to absorb the costs of imprudent investments.

The potential for major customer departure to CCAs was ever-present during the early high-volume RPS contracting conducted by SDG&E in 2010-2012. The City of Chula Vista, the second largest city in SDG&E service territory, had pursued the formation of a CCA in 2006.[5] One of four future scenarios examined in the PG&E Long-Term Procurement Plan application

---

[4] D. 10-12-048, *Decision Adopting the Renewable Auction Mechanism,* Appendix A, at pdf pp. 101-02 (Dec. 16, 2010) ("Procurement Requirement: Each IOU must enter into a standard contract with each winning bidder up to the capacity limits in each solicitation and total program capacity limits. IOUs select on the basis of least costly projects first until the IOU fully subscribes its allocated capacity for that auction.").

[5] San Diego Union Tribune, *Chula Vista Moves Toward Energy Freedom* (Oct. 19, 2006), *available at* http://legacy.sandiegouniontribune.com/uniontrib/20061019/news_lz6e19castane.html.

submitted to the Commission in 2006 assumed 10 percent customer departure to CCAs by 2012.[6] Marin Clean Energy launched in May 2010, before the Commission had approved any of SDG&E's in-state solar and wind contracts greater than 50 MW.[7] High-priced solar and wind contracting has had a predictable effect – complicating the departure of SDG&E customers to CCAs.

II. Background

Until the AB 1890 deregulation statute was enacted in 1996, California IOUs were vertically integrated electricity and natural gas providers,[8] owning all their own electric generating plants. SDG&E voluntarily sold off its electric generation fleet to third parties in the late 1990s, retaining only a 20 percent share in the San Onofre Nuclear Generating Station (SONGS).[9] In effect, SDG&E voluntarily limited itself to a transmission and distribution role by the end of the 1990s, while its parent company, Sempra, formed a separate company (Sempra Energy Resources) to build power plants.[10]

With the failure of deregulation in 2000-2001, California's IOUs began to partially return to vertical integration. SDG&E has taken the lead among California IOUs in this regard, with more natural gas-fired capacity under its ownership or direct control through tolling agreements in 2018,[11] than at any time in its history.[12,13] This gas-fired generation is identified as "brown power" in this proceeding. Since the enactment of the first renewable portfolio standard ("RPS") requirements in 2003, SDG&E has also entered into contracts for renewable resources ,including solar and wind generation, referred to as "green power" in this proceeding. The discussion that follows breaks down the major components of both classes of generation.

---

[6] PG&E, R.06-02-013, *PG&E 2006 Long-Term Procurement Plan, Order Instituting Rulemaking to Integrate Procurement Policies and Consider Long-Term Procurement Plans – Volume 1*, Table Vol. 1, IVB-3, p. IV-9 (Dec. 11, 2006).

[7] Marin Clean Energy webpage, "About Us," https://www.mcecleanenergy.org/about-us/ (last accessed Mar. 30, 2018).

[8] SCE is the exception, providing electricity only.

[9] SDG&E, 1999 FERC Form 1 at pdf p. 162 (June 29, 2001).

[10] Department of Water Resources, Energy Purchase Agreement Between Department of Water Resources and Sempra Energy Resources, Appendix B (Apr. 1, 2001).

[11] SDG&E, 2017 SEC Form 10-K at p. F-35, pdf p. 220 (Feb. 27 2018) ("Tolling Agreements: SDG&E has agreements under which it purchases power generated by facilities for which it supplies all of the natural gas to fuel the power plant (i.e., tolling agreements). SDG&E's obligation to absorb natural gas costs may be a significant variable interest. In addition, SDG&E has the power to direct the dispatch of electricity generated by these facilities.").

[12] SDG&E, 1995 FERC Form 1 at pdf pp. 225-29 (Apr. 26, 1996). Total fossil generation owned = 2,024 MW. Total nuclear generation owned = 451 MW.

[13] See Table 1*, supra*. Total fossil generation (excluding combined heat and power facilities), owned by SDG&E or controlled by SDG&E through tolling agreements = 2,803 MW.

A. Post Energy Crisis Power Procurement

Tale 1 below describes the major brown power purchases and contracts that SDG&E entered into following its return to vertical integration. The Commission authorized SDG&E to buy the 556 MW Palomar Energy Center from Sempra Generation in 2006.[14] The Commission authorized SDG&E to buy the 526 MW Desert Star Energy Center (formerly El Dorado Energy Center), located in Boulder City, Nevada, from Sempra Generation in 2011.[15] The Commission also authorized the sale of the 47 MW Cuyama peaker plant from a third party developer to SDG&E in 2011.[16] SDG&E can only include SDG&E-owned capacity in the PCIA calculation for the first ten years from the commissioning date.[17]

The Commission also authorized SDG&E to enter into multiple power purchase tolling agreements ("PPTA") with gas-fired generators. The largest is with Calpine for the 605 MW Otay Mesa Energy Center ("OMEC"). Under a tolling agreement, SDG&E pays for the fuel and has dispatch control over the plant.[18] In addition to OMEC, SDG&E has PPTAs with the following peaker plants: 98 MW Orange Grove, 47 MW El Cajon, 308 MW Pio Pico, and 500 MW Carlsbad Energy.[19] SDG&E also has long-term agreements with six combined heat and power qualifying facilities ("QF") that date from the 1980s.[20] These PPTAs and QF agreements are included in Table 1.

---

[14] SDG&E, 2006 SEC Form 10-K at p. 68 (Feb. 21, 2007). *(*"In March 2006, control and ownership of the 550-megawatt (MW) Palomar generating plant was transferred from Sempra Generation, which built the plant, to SDG&E. The CPUC has approved the revenue requirement for the plant as proposed by SDG&E.").

[15] CPUC Resolution E-4465, August 2, 2012.

[16] D.11-12-002, December 1, 2011.

[17] SDG&E Response to POC's Third Data Request, Response 1, R. 17-06-026 (Mar. 23, 2018).

[18] SDG&E, 2017 SEC Form 10-K at p. F-35, pdf. p. 220 (Feb. 27, 2018)..

[19] SDG&E, D. Sullivan 2016 ERRA Compliance Testimony at pdf. pp. 1031-1032 A.17-06-006 (June 1, 2017) ('Sullivan Testimony).

[20] *Id.*

Table 1. SDG&E natural gas-fired generation assets, owned or controlled through tolling agreements

Project	SDG&E-owned, tolling agreement, firm energy, or qualifying facility	Capacity, MW[21,22]	2016 Production, MWh[23]	Commercial online date (COD)	PCIA – eligible expiration date (IOU-owned) or contract end date
Palomar	SDG&E	566	2,299,052	2006	2016
Desert Star	SDG&E	536	1,223,034	2011	2021
Miramar	SDG&E	48	122,818	2005	2015
Miramar 2	SDG&E	48		2009	2019
Cuyamaca	SDG&E	47	8,173	2011	2021
OMEC	tolling	605	2,654,182	2009	2019 (contract end date)
Orange Grove	tolling	98	42,128	2010	2035 (transferred to SDG&E in 2035)
El Cajon	tolling	47	10,339	2010	2035 (transferred to SDG&E in 2035)
Pio Pico[24]	tolling	308	0	2017	2042
Carlsbad Energy[25]	tolling	500	0	2018 (estimated)	2038
Morgan Stanley[26]	firm energy	175	427,856	2013	2022
BP[27]	firm energy	68	150,114	2015	2019
Goal Line	CHP - QF[28]	50	23,018	2015	2025
Naval Station	CHP - QF	50	353,422	1989	2019
N. Island	CHP - QF	34	292,479	1989	2019
NTC	CHP - QF	23	150,314	1989	2019
NTC steam	CHP - QF	2.6	16,434	1989	2019
Yuma	CHP - QF	55	11,205	2015	2024
Gas-fired capacity, end of 2016:		2,453	7,784,568		
Gas-fired capacity, end of 2018:		3,261			

[21] SDG&E 2016 FERC Form 1 at pp. 402-03 (Apr. 1, 2017). Palomar = 566 MW, Desert Star = 526 MW.
[22] SDG&E 2016 Form 10-K at pdf p. 490 (OMEC = 605 MW).
[23] EIA, 2016 EIA-923, Page 4 Generator Data, Lines 2978-2980 (OMEC = 2,654,182 MW), Lines 3041-3043 (Desert Star = 1,223,034 MW), and Lines 3046, 3086, 3087 (Palomar = 2,299,052 MW).
[24] *Id.*
[25] *Id.*
[26] Sullivan Testimony at pdf p. 1032.
[27] *Id.*
[28] All CHP QF data from Sullivan Testimony, at pdf p. 1029.

SDG&E delivered 15,653,039 MWh to bundled customers in 2016.[29] Therefore, the average annual electricity demand in SDG&E service territory in 2016 was 1,787 MW. By the end of 2016, as shown in Table 1, SDG&E had over 2,400 MW of gas-fired capacity under ownership or some form of dedicated contract structure. The peak one-hour load in SDG&E service territory in 2016 was 4,343 MW on September 26, 2016.[30] About four-fifths of the load in SDG&E service territory is bundled customer load served by SDG&E, with the remainder Direct Access load served by others.[31] Therefore, assuming the same fraction applies to the bundled customer portion of peak load, about 3,475 MW of the 2016 summer peak load was attributable to SDG&E bundled customer load.[32]

By October of 2018, when the 500 MW Carlsbad Energy Center is scheduled to be fully online,[33] SDG&E will have about 3,300 MW of gas-fired generation under either its direct ownership, control through tolling agreements, or dedicated long-term contract. As a result, and assuming a peak load similar to 2016, SDG&E could meet its entire bundled customer load – nearly every hour of the year – with gas-fired generation already in its portfolio.

California IOUs have been subject to RPS requirements since 2003. The applicable current target is 50 percent RPS by 2030, with interim compliance goals.[34] At the time most of the RPS contracts at issue in this proceeding were approved by the Commission, the IOUs were subject to a requirement to achieve 33 percent renewables by 2020.[35] The metric the Commission used to assess the reasonableness of the pricing of these RPS contracts[36] was the market price referent ("MPR"), which represented the Commission's determination of the cost of production from a new combined cycle gas turbine power plant.[37] Though last calculated in 2011, the Commission continues to view the MPR as the "best available methodology to determine the cost savings (benefits) of the RPS program."[38]

B. The PCIA and its Market Price Benchmark

The Commission determines the above-market PCIA cost that departing load customers are responsible for by comparing the current market pricing for wholesale brown energy, capacity, and green power, which collectively form the "Market Price Benchmark" or "MPB," to

---

[29] SDG&E 2016 FERC Form 1 at p. 304, pdf. p. 180 (Apr. 1, 2017).
[30] *Id.* at p. 400, pdf p. 230.
[31] According to the California Energy Commission, the 2016 SDG&E all sectors electricity consumptions was 19,168.70 GWh, Therefore, percentage of SDG&E bundled customer load to total load = 15,653,039 MWh ÷19,168,700 MWh = 0.817 (~82 percent). *See* CEC, Electricity Consumption by Entity (webpage). http://www.ecdms.energy.ca.gov/elecbyutil.aspx (last accessed March 30, 2018).
[32] 0.80 x 4,343 MW = 3,474.4 MW.
[33] SDG&E, *SDG&E Procurement In Response to SONGS Retirement*, PowerPoint, at p. 3 (May 19, 2017).
[34] Senate Bill 350 (2015) (De León).
[35] *See* Executive Order S-14-08 (Nov. 17, 2008); Senate Bill X1-2 (2011).
[36] These RPS contracts fall under the umbrella term "green power" in this proceeding,
[37] CPUC, Padilla Report: Costs and Savings for the Renewables Portfolio Standard in 2016 (Pursuant to Public Utilities Code Section 913.3 at p. 10 (May 1, 2017) ("Padilla Report").
[38] *Id.* at p. 2, 10.

the actual generation charge paid by IOU ratepayers.[39] The PCIA is the difference between the actual generation charge paid by IOU ratepayers and the MPB. Although the MPB is intended to serve largely the same function as the MPR—assigning a market value to the IOUs' generation portfolios—the two metrics are distinct.[40]

The PCIA uses real-time "market value" for brown power, green power, and capacity payments to establish an idealized, lowest-cost bundled IOU customer generation charge, and then requires departing load customers to pay the difference between the idealized, lowest-cost charge and what the IOU customers actually pay.

This indifference criterion described in the R. 17-06-026 Order Instituting Rulemaking is applicable to the CRS-eligible brown power resources and green power resources. These brown power and green power resources also provide varying levels of reliable capacity to meet demand during times of peak load. Resource adequacy payments are made to these resources to assure their availability when needed for reliability purposes.[41] These are the three resource types that comprise the PCIA. The sections that follow unpack these resources and show why the majority of contracts for them should not factor into a PCIA charge.

III. Actual SDG&E procurement costs are unrelated to market value costs used in the PCIA

The net result of the brown power and green power commitments SDG&E has made is that SDG&E bundled customers paid a generation charge of approximately $0.096 per kilowatt-hour (kWh) in 2016.[42] This is about one-half the total retail charge paid by SDG&E customers, which includes transmission and distribution, public purpose programs, and the DWR bond charge, of about $0.20/kWh.[43] In other words, the retail cost paid by SDG&E ratepayers for SDG&E's power procurement portfolio, at a time when there are no operational CCAs in SDG&E territory, is about $100 per megawatt-hour.

The actual cost of generation passed on to bundled ratepayers by SDG&E for its two CRS-eligible combined cycle units, Desert Star and OMEC, is $66/MWh, as shown in Table 2.[44] The actual average SDG&E brown power energy cost, when all forms of brown power are included, is about $74/MWh.[45] The average brown power energy cost paid by SDG&E bundled customers is closer to the 2011 cost of energy production calculated in the MPR from a new

[39] *See* CPUC, Fact Sheet: Power Charge Indifference Adjustment at p. 2 (Jan. 2017). The actual generation charge paid by IOU ratepayers is equivalent to the utility's "actual portfolio cost."
[40] Commission Resolution E-4475; D.11-12-018.
[41] CPUC, Resource Adequacy (webpage), http://www.cpuc.ca.gov/RA/ (last accessed March 31, 2018).
[42] CPUC, California Electric and Gas Utility Cost Report at Figure 1-4, p. 7 (Apr. 2017).
[43] *Id.*
[44] SDG&E Response to POC's Third Data Request, Response 1 at p. 4, R. 17-06-026 (Mar. 23, 2018).
[45] 2016 cost of brown power energy ÷ brown power energy production = $185,181,379 ÷ 2,516,476 MWh = $73.59/MWh. *See* Table 2, *supra*.

combined cycle unit, at $89/MWh,[46] than the market value of approximately $33/MWh used by SDG&E in its 2017 and 2018 PCIA calculations. The use of a $33/MWh market value for brown energy in the SDG&E PCIA calculation bears no relation to the actual cost incurred by SDG&E bundled customers for most of the brown power currently provided to them by SDG&E.

Table 2. Actual SDG&E CRS-eligible brown power resources and associated capacity and energy production costs in 2017 PCIA calculation[47]

Class of "Brown" Power/Resource Type	2017 Net Qualifying Capacity (MW)	2017 Forecast Generation (GWh)	2017 ERRA Unit Cost forecast ($/MWh)	2016 Capacity Costs (FERC Form 1)	2016 Energy Costs (FERC Form 1)	Unit capacity cost, $/kW-yr	Production 2016, MWh
Natural Gas Combined Cycle	1,023	[redacted]	$66	$125,044,852	$102,362,015	122	1,550,940
Natural Gas Fired Peaker	237	[redacted]	$473	$41,118,852	$5,021,264	173	10,616
Pumped Hydro	40	[redacted]	$67	$2,732,375	$268,016	68	4,000
Unspecified Power Contract	190	[redacted]	$84	$ -	$51,231,573	--	609,900
Combined Heat and Power	181	[redacted]	$77	$39,756,703	$26,566,527	147	345,020
	1,671			208,652,782	185,449,395		2,520,476

The same is true regarding capacity costs. The average actual SDG&E CRS-eligible brown power capacity cost is about $143/kW-year,[48] which far exceeds SDG&E's assumed market value of capacity of $58.27/kW-year in its 2017 and 2018 PCIA calculations.[49] The CRS-eligible capacity cost that SDG&E customers are now accustomed to paying is nearly three times the market value of capacity that SDG&E assumes in the 2017 and 2018 PCIA calculations. Again, the average actual SDG&E CRS-eligible brown power capacity cost of $143/kW-year approximates the assumed capacity cost in the 2011 MPR of about $170/kW-yr.[50]

---

[46] Commission Resolution, E-4422, http://docs.cpuc.ca.gov/WORD_PDF/FINAL_RESOLUTION/154753.PDF (Dec, 1, 2011). Resolution E-4422, Appendix A, xls spreadsheet:

[47] SDG&E Response to POC's Third Data Request, Response 1 at p. 4, R. 17-06-026 (Mar. 23, 2018).

[48] See POC Opening Testimony, Table 2, p. --. 2016 cost of brown power energy ÷ brown power energy production = $185,181,379 ÷ 2,516,476 MWh = $73.59/MWh.

[49] SDG&E Response to POC's First Data Request, R. 17-06-026 (Jan. 24, 2018) (Attachment - 2017 PCIA calculation spreadsheet; SDG&E 2018 PCIA calculation spreadsheet, included as pp. 32-34 in the SDG&E PowerPoint presented at the PCIA workshop in San Diego, titled "SDG&E, PCIA Rulemaking Workshop #1C, December 6, 2017").

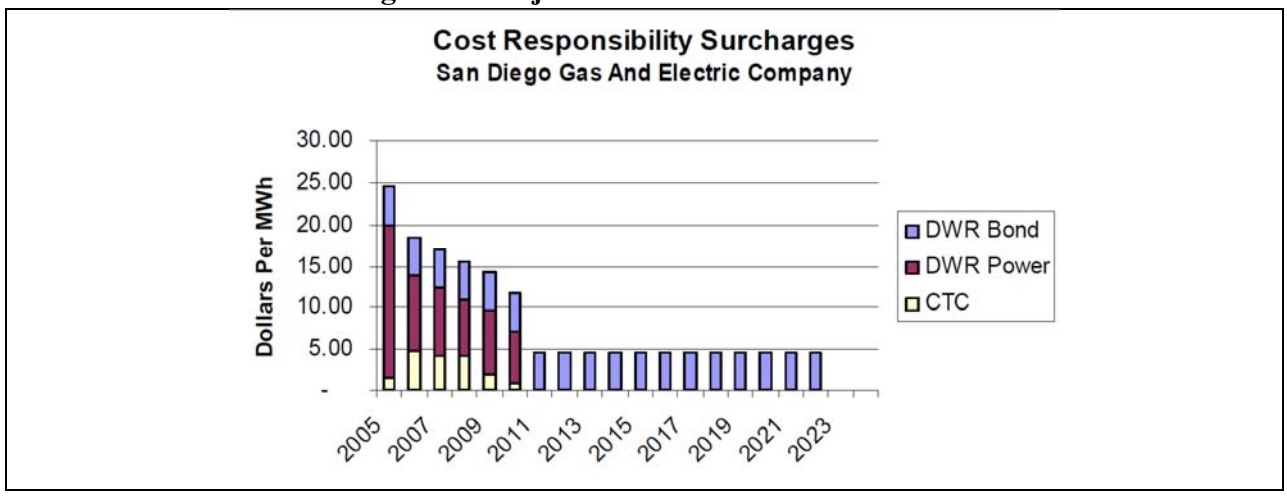
[50] CPUC, Resolution E-4422, *Adoption of 2011 Market Price Referent values for use in the 2011 Renewables Portfolio Standard solicitations* (Dec. 1, 2011) (attached xls worksheet, "Control Sheet" tab. 2011 MPR capacity value = $170.77/kW-yr).

SDG&E identifies a total of 1,441 MW of brown power and 40 MW of pumped hydro net qualifying capacity ("NQC") resources under contract in 2016, as shown in Table 2. SDG&E reports 2,520,476 MWh of energy production in 2016 from these resources and "unspecified power contracts" in its data response to POC, as shown in Table 2 above. The 2016 cost of this capacity and energy is $394,102,177.[51] However, in its 2017 PCIA calculation, SDG&E indicates that its CRS-eligible brown power resources provide 2,708 MW[52] of NQC and produce 5,491,000 MWh at a cost of $632,797,000.[53] There is a substantial discrepancy between the CRS-eligible brown power resources that SDG&E described in its data response to POC and the total CRS-eligible brown power resources assumed in the 2017 PCIA spreadsheet.

IV. Brown Power Contracts Should Comprise a Diminishing Part of the PCIA

Utilities are authorized to assess a surcharge – the CRS. The concept behind the CRS is that, for certain types of generation contract obligations, the utility is authorized to spread the cost across its entire bundled customer base at the time the obligation is entered into, and any customers departing subsequently – for example to join a CCA – must continue to pay their share of the obligation. The CRS was originally associated only with the 10-year Department of Water Resources ("DWR") contracts signed by the state during the 2000-2001 energy crisis. One of the first CCA technical feasibility studies in SDG&E service territory, prepared by Navigant for San Diego County in 2005, showed the magnitude and rate of decline of the CRS. This graphic is shown in Figure 1.

Figure 1. Projected SDG&E CRS in 2005[54]



CTC: Competitive Transition Charge

[51] Table 2, $208,652,782 (capacity) + $185,449,395 (energy, including pumped storage) = $394,102,177.
[52] SDG&E 2017 PCIA spreadsheet: 3,400 MW (CRS-eligible NQC) – 692 MW (renewables NQC, SDG&E DR response to POC-03, at p. 5) = 2,708 MW.
[53] *Id.*. $1,254,797,000 (CRS-eligible portfolio cost) – $622,000,000 (2016 total green power payments, SDG&E A.17-06-006 D. Sullivan testimony, June 1, 2017, pdf pp. 1034-1036) = $632,797,000 (brown power cost).
[54] Navigant, *County of San Diego CCA Technical Feasibility Study* at p. 51 (May 2005).

Navigant observed in the 2005 San Diego County study that the CRS could undermine the economic benefit of CCA stating:

> The single greatest obstacle to achieving significant cost savings through CCA in the next several years is SDG&E's imposition of cost responsibility surcharges on CCA customers, which are designed to shield SDG&E from any financial losses from cost increases that might result from customers switching to service by Aggregator.[55]

In fact, the base case scenario in the study assumed a CRS of $0.020/kWh, which made CCA energy more costly in the first few years of service than energy SDG&E delivered.[56] With the CRS at $0.010/kWh, the CCA was more cost-effective than SDG&E in all years.[57]

As shown in Figure 1, the CRS was projected in 2005 to end in 2011[58] as that was the year the 10-year DWR contracts were to end. However, nearly half of the MWhs included in the SDG&E 2017 and 2018 PCIA calculations is recent, post-DWR-contract brown power capacity.[59] The actual unit cost of brown and green power in the 2017 SDG&E PCIA calculation, which uses 2016 data, is shown in Table 3. The "cost" column in Table 3 includes both energy and capacity payments. The "total unit cost" column includes both energy and capacity payments levelized over the MWh quantity of energy produced in 2016.

Table 3. Unit cost of 2016 SDG&E CRS-eligible brown power expenses and green power contracts

Power type	Quantity, MWh	Cost, $	Capacity,[60] MW	Total unit cost, $/MWh
Brown	5,491,000[61]	632,797,000	1,441	115
Green	6,899,000[62]	622,000,000	692	90

The cost of long-term PPA contracts for brown power resources that the Commission has identified as necessary for grid reliability generally are to be spread equally over all customers,

[55] *Id.* at p. 50.
[56] *Id.* at pp. 50-52, 68 (Case 1: Base Case).
[57] *Id.* at p. 71 (Case 4: CRS Is Reduced By 50% From Base Case).
[58] With the exception of the $0.005/kWh DWR bond charge which ends in 2023.
[59] SDG&E Response to POC's First Data Request, R. 17-06-026 (Jan. 24, 2018) (Attachment - 2017 PCIA calculation spreadsheet)
[60] SDG&E Response to POC's Third Data Request, Response 1 at p. 4, R. 17-06-026 (Mar. 23, 2018), p. 5. Note that 40 MW of capacity associated with pumped hydro is included with green power capacity.
[61] SDG&E Response to POC's First Data Request, R. 17-06-026 (Jan. 24, 2018) (Attachment - 2017 PCIA calculation spreadsheet). CRS eligible supply – CRS renewable supply = 12,460 GWh – 6,969 GWh = 5,491 GWh. Estimated CRS-eligible brown power cost = $1,254,797,000 - $622,000,000 = $632,797,000.
[62] Sullivan Testimony at pdf pp. 1029-1031. Total 2016 MWh and cost, 6,899,000 MWh and $622,000,000 respectively, for all "Renewable Energy" contracts, including Badger Filtration Plant and San Francisco Peak Hydro conduit-hydro QF projects listed on pdf p. 1029.

including CCA and DA customers.[63] These projects are known as CAM projects.[64] The two CAM projects in SDG&E's brown power portfolio are 308 MW Pio Pico Energy Center[65] and the 500 MW Carlsbad Energy Center.[66] CAM costs are by definition direct pass-through costs that CCA and DA customers must pay and therefore should not be included in the PCIA calculation.

SDG&E buys relatively little wholesale "market value" brown power, which SDG&E values at about $33/MWh in it 2017 and 2018 PCIA calculations. SDG&E projected in April 2017 that 35 percent of its customer power requirements in 2017 would come from green power, 45 percent from SDG&E-owned generation and tolling contracts, 15 percent from wholesale market purchases, and 5 percent from other long-term contracts.[67] In other words, only a quarter of the brown power consisted of wholesale market purchases.[68] The bulk of the brown power was supplied by SDG&E-owned generation (its 566 MW Palomar Energy Center and 526 MW Desert Star Energy Center) and the 605 MW OMEC combined cycle project, which SDG&E controls through a tolling agreement. Collectively, these three combined cycle plants produced 6,176,268 MWh of energy in 2016.[69]

Two of the largest brown power generators in SDG&E's portfolio, the 605 MW OMEC project and the 526 MW Desert Star combined cycle project, will "term-out" in 2019 and 2021, respectively. Upon doing so, they can no longer form part of the PCIA, which has a 10-year limit on recovery of utility-owned generation costs through the PCIA.[70] Desert Star was purchased by SDG&E from Sempra Generation in 2011 and will be subject to the 10-year limit on recovery of utility-owned generation costs through the PCIA in 2021.[71] The 10-year power purchase tolling agreement between SDG&E and OMEC ends in 2019.[72] Unless SDG&E purchases OMEC from

---

[63] D.11-05-005, Decision Modifying New Generation and Long-Term Contract Cost Allocation Mechanism Pursuant to Senate Bill 695, at p. 3 (May 5, 2011).
[64] *Id.* at p. 7.
[65] D.14-02-016, Decision Granting SDG&E Authority to Enter Into a Purchase Power Tolling Agreement with Pio Pico Energy Center, LLC at p. 15, Conclusion of Law No. 8 (Feb. 5, 2014) ("As our approval of the amended PPTA is for purposes of meeting local reliability criteria, CAM treatment is appropriate and reasonable.").
[66] D.15-05-051, Decision Conditionally Approving SDG&E'S Application for Authority to Enter Into Purchase Power Tolling Agreement with Carlsbad Energy Center, LLC at p. 36, Conclusion of Law No. 12 (May 21, 2015).
[67] SDG&E, 2016 FERC Form 1 at pdf p. 103 (Apr. 1, 2017).
[68] *Id.*
[69] Table 1, *supra*. 2016 combined cycle plant production = 2,299,052 MWh (Palomar) + 1,223,034 MWh (Desert Star) + 2,654,182 MWh (OMEC) = 6,176,268 MWh.
[70] SDG&E Response to POC's Third Data Request, Response 1 at pp. 1-2, R. 17-06-026 (Mar. 23, 2018). This 10-year limit is the reason that 556 Palomar Energy Center and 98 MW Miramar are not included as CRS-eligible resources.
[71] CPUC Resolution E-4465 (Aug. 2, 2012), available at http://docs.cpuc.ca.gov/word_pdf/COMMENT_RESOLUTION/169867.pdf.
[72] 2016 SDG&E FERC Form 1, at pdf p. 41 (Page 123.2).

Calpine, which it has an option to do,[73] OMEC will no longer form part of the brown power ledger in the SDG&E PCIA calculation after 2019.

Table 2 lists the IOU-owned PCIA applicability termination dates and PPA or QF contract termination dates in the right-hand column. These termination dates indicate that brown power resources should comprise a diminishing part of the PCIA in future years. Within one to three years, a substantial component of SDG&E's CRS-eligible brown power procurement will no longer be eligible for PCIA treatment. New contracts, specifically the Pio Pico and Carlsbad Energy Center contracts, are CAM projects with pass-through costs to all ratepayers that should not be included in the PCIA calculation. With renewables taking up an increasingly large slice of the utilities' portfolio, and with load departures forecasted to increase, there is no basis for substituting expiring CRS-eligible brown power contracts with new brown power capacity.

Finally, it is possible the high PCIA is being driven by brown power contracts that are not eligible for PCIA costs. There is a large discrepancy between the CRS-eligible brown power resources that SDG&E affirmatively identifies in data responses to POC and the brown power energy production and the RA contribution of these resources, shown in the 2017 and 2018 PCIA calculations. SDG&E accounts for 2,516,476 MWh of CRS-eligible brown power 2016 energy production in its data response to POC.[74] However, SDG&E assumes 5,491,000 MWh of CRS-eligible brown power energy production in 2016 as an input to the 2017 PCIA.[75] This discrepancy calls into question whether SDG&E is including ineligible contracts in the PCIA calculation of brown power resources (possibly costs for CAM projects or utility-owned brown power resources that have passed ten years of operation).[76]

V. SDG&E overpaid for most of its utility-scale solar and wind PPAs

A. Solar project case study

1. Early high priced contracts approved by the Commission set an artificially inflated benchmark for utility-scale solar

The Commission's least-cost best-fit ("LCBF") procurement framework is intended to govern IOU procurement of green power resources. Decisions D. 03-06-071 and D. 04-07-029 adopted criteria for the rank ordering and selection of LCBF renewable resources for use by the IOUs in

[73] SDG&E 2016 Form 10-K at pdf p. 118
[74] SDG&E Response to POC's Third Data Request, Response 1 at p. 4 (excluding pumped hydro MWh), R. 17-06-026 (Mar. 23, 2018).
[75] SDG&E Response to POC's First Data Request, R. 17-06-026 (Jan. 24, 2018) (Attachment - 2017 PCIA calculation spreadsheet). CRS eligible supply – CRS renewable supply = 12,460 GWh – 6,969 GWh = 5,491 GWh.
[76] *See* SDG&E Response to POC's Third Data Request at p. 1 (Mar. 23, 2018) (stating that brown power resources are not included in the PCIA if they have "exceeded the ten-year limit on recovery of utility-owned generation costs through the PCIA").

RPS solicitations.[77] These decisions also established the role of the independent evaluator ("IE") and procurement review group ("PRG") in evaluating the reasonableness of RPS contracts.[78] In concept, based on these Commission decisions, the IOUs methodically rank-order bids received in RFO processes based on the criteria listed in Table 4, and enter into contracts with the highest ranked bidders.

Table 4. Least-cost, best fit RPS bid evaluation process[79]

1. Net Market Value
    a. Benefits (Energy, Capacity, Ancillary Services)
    b. Contract Payments
    c. Transmission Network Upgrade Costs (also called a "transmission adder")
    d. Congestion Cost
2. Portfolio-Adjusted Value
    a. Location
    b. RPS Portfolio Need
    c. Energy Firmness
    d. Curtailment
3. Project Viability
4. RPS Goals
5. Supplier Diversity

The IOUs also have the discretion to evaluate bids received outside of the formal RFO solicitations and enter into contracts with those counterparts. Most of SDG&E's solar and wind contracts greater than 50 MW capacity signed in 2010 or later are bilateral contracts that were not selected as part of an RFO solicitation. However, the LCBF standard applies to all RPS contracts, whether as a result of an RFO solicitation process or through a bilateral negotiation.[80,81] The intent of the LCBF process is clear – that the lowest-cost, viable green projects receive contracts.

---

[77] See PG&E 2014 RPS RFO preamble at p. 1: https://www.pge.com/includes/docs/pdfs/b2b/wholesaleelectricsuppliersolicitation/RPS2014/Attachment_K_LCBF_01052015.pdf.

[78] D.03-06-071 and D.04-07-029.

[79] See PG&E 2014 RPS RFO preamble at p. 2.

[80] CPUC Resolution E-4358, *SDG&E requests approval of an amended and restated renewable power purchase agreement with Pacific Wind, LLC* at p. 5 (Sept. 23, 2010) ("Energy Division evaluated the bilateral amended and restated PPA."); *Id.* at p. 8 ("The amended and restated PPA was evaluated consistent with the LCBF methodology identified in SDG&E's 2009 RPS Procurement Plan.").

[81] D.09-06-050, *Decision Establishing Price Benchmarks and Contract Review Processes for Short-Term and Bilateral Procurement Contracts for Compliance with the California Renewables Portfolio Standard* at p. 34, Finding of Fact No. 15 (June 18, 2009) ("In order to promote consistency of evaluation of all RPS procurement contracts, it is reasonable to authorize Energy Division staff to review bilateral RPS contracts using the same methods and criteria, including those for reviewing price reasonableness, as are used to review contracts that result from the utilities' annual RPS solicitation, using the MPR as a price reasonableness benchmark for long-term bilateral contracts."

Despite the clear intent of the LCBF procedure, many of SDG&E's post-2008 solar and wind PPAs for projects greater than 50 MW, which form the overwhelming majority of SDG&E's solar and wind capacity, were not competitively priced, followed ad hoc, qualitative selection criteria disconnected from the concept of "best price from qualified bidders," and disregarded the utility's obligation to maintain just and reasonable rates per section 454.5 of the PUC Code. As discussed below, the LCBF framework initially functioned as intended to guide IOU procurement of resources at competitive prices but soon gave way as unreasonably high-priced projects were approved and set the benchmark against which future projects were evaluated.

The first utility-scale solar project PPA between a California IOU and a third-party solar developer approved by the Commission was the SCE-NRG January 2009 PPA for the 21.5 MW Blythe Solar LLC project.[82] The contract price for this project between SCE and the solar panel manufacturer First Solar was $89.625/MWh with an additional time-of-day (TOD) price adjustment.[83]

SCE followed a methodical bid evaluation process in this case. The Blythe solar project was among projects bidding in response to SCE's 2007 RPS RFP. According to the IE, Sedway Consulting, the response to SCE's 2007 (RPS RFP) was quite robust.[84] SCE established a five-tier merit-order ranking system to categorize the bids received:[85]

1. Projects within SCE's service territory with well-defined proposals that complied with SCE's RFP,
2. Projects within SCE's service territory with less-well-defined proposals that did not comply with SCE's RFP or seemed problematic,
3. Projects outside of SCE's service territory but within the CAISO grid,
4. Projects outside of CAISO with baseload energy deliveries that could potentially be scheduled as firm imports, and
5. Projects outside of CAISO with intermittent energy deliveries.

"Sedway Consulting reviewed SCE's grouping decisions and ranked each group's proposals based on their economic value (benefit/cost ratio), confirming SCE's selection of the top-ranked proposals in each of the groups."[86] The Blythe project pricing was below the 2007

[82] CPUC Resolution E-4157, Approval of RPS PPA FSE Blythe 1, LLC at p. 9 (July 10, 2008)
[83] SCE, Renewable Power Purchase and Sale Agreement between Southern California Edison Company and FSE Blythe 1, LLC (RAP ID #5207), December 21, 2007, p. 4 and pp. 37-38.
[84] SCE, Advice Letters 2198-E/E-A/E-B, December 10, 2008, Attachment 2 (Dec. 1, 2008): Sedway Consulting, Independent Evaluation Report for Southern California Edison's 2007 Renewable Resource Solicitation at p. 7 (Dec. 31, 2007).
[85] *Id.* at p. 8.
[86] CPUC Resolution E-4157, Approval of RPS PPA FSE Blythe 1, LLC at p. 9 (July 10, 2008) ("This contract is below the 2007 MPR and will not be applied to SCE's cost limitation.").

MPR.[87] In the case of this PPA, selection based on best price appears to have been the primary driver for bid selection.

The energy price in the FSE Blythe 1 PPA is consistent with the publicly-stated pricing described by the developer, First Solar, at the time. First Solar was an active participant in the Renewable Energy Transmission Initiative ("RETI"), led by the California Energy Commission ("CEC"). The Commission was also an active party in RETI. First Solar identified a levelized cost-of-energy of $90/MWh as achievable in its April 4, 2008 comment letter in the RETI process.[88] This comment letter was written approximately three months after SCE and First Solar had signed a PPA for FSE Blythe 1 with an energy price of $89.625/MWh, and a TOD adjustment.[89,90]

The April 2008 First Solar PPA shows that solar PV was cost competitive as early as 2008 and outperforming solar thermal technology in pricing. First Solar challenged RETI contractor Black & Veatch's position that all solar PV technologies should have a similar cost of energy.[91] First Solar points out that approval of the cost-effective FSE Blythe 1 PPA was pending before the Commission.[92] Finally, First Solar summarizes recent studies of the cost of solar thermal projects with an average levelized cost-of-production of approximately $170/MWh.[93]

The intended effect of the LCBF framework—to guide reasonable and competitive procurement—was lost with the next solar PPA approved by the Commission, the 10 MW El Dorado solar project developed by Sempra Generation, which represented PG&E's first large-scale solar PPA. The El Dorado solar project uses the same PV technology (First Solar) as the FSE Blythe 1 project. The PPA was approved by Commission in June 2009, with an energy price of $139/MWh and a TOD adjustment. The El Dorado solar project was approved by the Commission six months after the Blythe solar project was approved, used the same solar PV technology as Blythe, but was priced $50/MWh higher than the Blythe PPA.

It was known at the time of contracting that the El Dorado project failed to perform well in the LCBF framework and that far more prudent investment opportunities existed. The project's location in Boulder City, NV put it outside the CAISO control area, and as such the project would have been classified in the lowest of the five merit order tiers established by SCE. The IE report noted numerous weaknesses in the El Dorado PPA (including that there was the appearance of favoritism toward Sempra Generation by PG&E and that the project ranked low

---

[87] *Id.*
[88] First Solar, Comments on the Renewable Energy Transmission Initiative (RETI) Phase 1A DRAFT Report at p. 1 (Apr. 4, 2008) [
[89] SCE-FSE Blythe 1 PPA at pp. 4, 84 (Dec. 21, 2007).
[90] The energy price also included a time-of-day ("TOD") price adjustment described on pp. 37-38..
[91] First Solar, Comments on the Renewable Energy Transmission Initiative (RETI) Phase 1A DRAFT Report at p. 1 (Apr. 4, 2008).
[92] *Id.* at p. 2.
[93] *Id.* at p. 3.

among the bids received), but concluded that since no other bidders were harmed by the PPA, the contract should be approved by the Commission.[94]

The IE report's executive summary states:[95]

> Arroyo (Seco Consulting) identified specific concerns regarding the process by which the El Dorado project was added to PG&E's short list after the list was finalized and provided to the CPUC on July 15, 2008. These concerns were communicated to PG&E's RPS RFO steering committee on August 8, 2008, as it considered, then made a decision to include El Dorado on the short list for negotiation. These specific concerns about how the El Dorado offer was treated, involving apparently preferential treatment of Sempra Generation by PG&E, create an appearance that the process that led to its inclusion in the short list, weeks after a short list was submitted to the CPUC, was less than fully fair."

The IE report notes that the RPS procurement process established by state legislation required that the PG&E procurement process use criteria for the selection of LCBF renewable resources.[96] However, it goes on to note that the process that PG&E used to select a short list of projects "makes greater use of subjective judgment to consider the import of non-valuation criteria, as opposed to relying on an objective analysis or on a quantitative weighing formula."[97]

The IE goes into some detail on the weaknesses of relying on subjective judgment to bid selection purposes:[98]

- Relying on subjective judgment to create the short list opens the risk that other considerations than those publicly identified within the Solicitation Protocol's stated list of non-valuation criteria may play a role in selecting or rejecting Offers for the short list. This risk is lower when a mechanical weighting approach or other objective process is used to incorporate the non-valuation criteria in creating the short list.
- The valuation methodology has some properties that, when combined with the specific elements of some Offers, may appear counterintuitive to some observers.

---

[94] PG&E, Advice Letters 3386-E and 3386-E-A, December 22, 2008, IE report, pdf. pp 20-72.
[95] CPUC Resolution E-4240, p. 7: PG&E did not receive Commission approval of its PPA with El Dorado Solar prior to taking deliveries under the PPA. In general, CPUC approval is required for generation under a PPA to be used for RPS compliance. p. 13: As a general rule, this Commission requires that a utility seek approval of long-term contracts prospectively. PG&E accordingly placed itself at some risk by incurring costs under the PPA, as the Commission could potentially deny or condition approval of the PPA. Under the specific circumstances of this case, the Commission concludes that advice letter should be approved, despite PG&E's "jumping the gun."
[96] *Id.* at pdf p. 31.
[97] *Id.* at pdf p. 35.
[98] *Id.* at pdf. p, 37.

Ultimately the IE report claimed that the contract was acceptable despite many flaws in the process, including the project scoring poorly relative to other bids and required wheeling through an out-of-state utility,[99,100] because no other bidder was injured by the PPA. This is an illogical conclusion. Other bidders were denied 10 MW of PG&E solar procurement awarded to Sempra Generation, and ratepayers were left with far higher costs than were reasonable for solar power at the time.

Approval of the El Dorado PPA based on purely qualitative criteria at a far higher price than the SCE Blythe solar project points to the problems inherent in a confidential PPA procurement process that relies too heavily on the independent evaluator and the Procurement Review Group to assure price reasonableness. The subjective process utilized by PG&E to select the Sempra Generation bid produced a poor result for ratepayers. The agreed upon energy price of $139/MWh was more than 50 percent higher than the $89.625/MWh energy price agreed upon in the FSE Blythe 1 contract approved by the Commission six months earlier, for the same solar technology and at a time when solar prices were declining rapidly.

The approval of this PPA pushed the cost of thin-film solar from demonstrably least cost into the same range as other forms of solar PV and solar thermal, and shifted the bid selection criteria from LCBF to "subjective and counterintuitive."

The approval of the El Dorado Solar PPA opened the door to an "anything goes" attitude toward solar and wind PPA pricing after 2008, with subsequent utility-scale RFO and bilateral solar and wind PPAs consistently 50 to 100 percent above verifiable competitive market pricing for the date the contracts were approved by the Commission. Table 5 includes only California IOU solar projects using First Solar panels to demonstrate how misaligned with LCBF principles the contract price of solar became following the approval of the PG&E-Sempra Generation El Dorado Solar PPA.[101]

Table 5. IOU PPA contract prices for solar projects using First Solar thin-film PV

Project[102]	IOU	Capacity, MW	PPA approval date by CPUC	Energy cost, $/MWh	TOD adjustment
FSE Blythe 1	SCE	21.5	January 2009	89.625	Y

[99] *Id.* at pp. 51-53 "Based on the valuation of the El Dorado PPA compared to other Offers as initially priced, and on the PPA's pricing compared to the proposed Market Price Referent, Arroyo's judgment is that the El Dorado contract ranks low in market valuation. . . The proposed project would impose the burden of a contract price that today appears to be both relatively high when compared to competing Offers, and absolutely high when compared to the proposed MPR, on ratepayers for twenty years. . . The handling of the El Dorado involved preferential concessions to Sempra Generation that tend to create the appearance of unfair treatment."

[100] *Id.* at p. 35. "PG&E had originally applied a TRCR (transmission) adder to the economics of the El Dorado offer . . . The physical location of the El Dorado substation (Southern Nevada) is far from PG&E's service territory."

[101] This is a partial list of California IOU solar PPAs where First Solar technology is utilized. The relevant pages from each PPA listed in Table 5 are included in **Attachment A**.

[102] SCE Advice Letter (AL) 4107-E at pp. 21-22, September 10, 2012.

				(no annual increase)	
Topaz Solar	PG&E	550	Feb 2009	104.00	Y
El Dorado	PG&E	10	July 2009	139.00	Y
Agua Caliente	PG&E	290	June 2010	147.50	Y
AV Solar Ranch	PG&E	230	March 2010	129.25	Y
Desert Sunlight	SCE	250	Sept 2010	119.50 (+1% per year)	Y
Campo Verde	SDG&E	139	May 2012	113.00	Y

Failure to prioritize the LCBF standard following the Commission's approval of the El Dorado PPA resulted in many high-cost, above-MPR PPAs, such as the 250 MW Mojave solar thermal project. Former Commissioner Mike Florio characterized the Mojave solar thermal project as burdening ratepayers with $1.25 billion in excessive life-of-contract costs.[103] It was a bid selection process failure that led to these inflated solar bids being awarded PPAs, and not a lack of competitively-priced bids that would have eliminated ratepayer exposure to above market contract costs.

2. TOD adders drove up contract prices even further

The inclusion of a TOD adjustment to California IOU solar PPAs, in addition to the already inflated contract price, inflated payments even further. The value of electricity varies throughout a 24-hour day relative to the electricity demand in those hours. The highest demand for electricity occurs on weekday afternoons in the summer months. Solar output is greatest at mid-day and early afternoon. As a result, the application of a TOD value adjustment increases the "all-in" price paid to the solar operator by about 20 percent on average. This is shown in Table 5 for a number of the large solar projects in SDG&E's portfolio.

[103] Forbes, *California Approves High-Priced Mojave Solar Project Over Objections*, November 10, 2011. "The PPA unnecessarily saddles ratepayers with extraordinary above-market costs - $1.25 billion," said Commissioner Mike Florio, who voted against the contract at Thursday's meeting. "We could probably get almost 500 megawatts of renewable energy for the price we're paying for this 250 megawatts." See: https://www.forbes.com/forbes/welcome/?toURL=https://www.forbes.com/sites/toddwoody/2011/11/10/california-approves-high-priced-mojave-solar-project-over-objections/&refURL=https://www.google.com/&referrer=https://www.google.com/.

Table 5. Impact of TOD adjustment on the unit price paid by SDG&E for utility-scale solar power[104]

Project	Capacity, MW	2016 MWh Production	Base contract price w/o TOD, $/MWh	Payment by SDG&E, $	Effective price w/ TOD,[105] $/MWh	Unit price increase w/TOD, %
Arlington Valley	127	364,397	108	44,445,979	122	13
Catalina Solar	110	269,372	113	34,954,456	130	15
CSolar IV South	130	292,750	126	43,930,768	150	19
Imperial Valley Solar	200	535,403	99	67,077,350	125	27

California IOUs pay a TOD adjustment to solar developers in addition to the contracted energy price. Other Southwestern IOUs, such as Public Service of New Mexico ("PNM") and NV Power, do not pay a TOD adjustment.[106,107]

The TOD adjustment is not inherently flawed. For example, it could be used to put a portion of a LCBF contract at performance risk, where full payment of a competitive contract price must be earned by maintaining the facility in top condition. That is how it appears to have been used by bids in the RAM procurement process, which achieves least-cost pricing with a TOD adjustment.[108] However, when added to the cost of contracts that already exceeded market value at the time, the TOD adder made these contracts even more expensive.

3. Low-cost RAM contracts derived from a competitive auction provide a benchmark to evaluate the imprudent component of solar PPAs

The Renewable Auction Mechanism ("RAM") procurement process for projects 20 MW and less, based on price-based competitive bidding and standard offer contracts, resulted in far lower PPA prices – one-half the price of utility-scale contracts in some cases–for smaller solar projects in SDG&E territory. This discrepancy is counter-intuitive, as economy-of-scale principles would anticipate lower prices for utility-scale projects. The discrepancy is due to the

[104] SDG&E, A.17-06-006 D. Sullivan 2016 ERRA Compliance Testimony, June 1, 2017, at pdf p. 1030 and pp. 1035-1036.
[105] Arlington Valley example: [(total SDG&E 2016 payment) ÷ [(energy price)(energy production)]] = $44,445,979 ÷ $39,354,876 = 1.129 (12.9 percent increase).
[106] New Mexico PRC Recommended Decision Case No. 12-00131-UT, In the Matter of PNM's Renewable Energy Portfolio Procurement Plan for 2013, November 7, 2012, p. 31.
[107] Nevada Power Company, Nevada Public Utilities Commission Application A.15-07---, Seeking Approval of a 100 MW PPA with SunPower and a 100 MW PPA with First Solar, July 1, 2015.
[108] SDG&E, RAM Power Purchase Agreement Between SDG&E and Cascade Solar, LLC, October 19, 2012.

fact that RAM auctions prioritize objective cost competitiveness while utility-scale solar PPAs were selected through the subjective and skewed process described above. RAM contracts, which represent the market value of solar PV projects at the time, provide a benchmark against which to assess the avoidable component of utility-scale PPA pricing.

In 2010, the Commission in D. 10-12-048 adopted the 1,000 MW RAM program to create "a simplified market-based procurement process for smaller RPS projects."[109] The first RAM auction closed on November 15, 2011.[110] The RAM program was "designed to reduce transaction costs by providing a streamlined contracting mechanism utilizing a standard contract while at the same time relying on market-based pricing."[111] It was "intended to complement the RPS Program by providing a procurement opportunity for smaller RPS-eligible projects which have not been able to effectively participate in the RPS solicitations."[112]

In its December 2012 advice letter to the Commission requesting approval of the 18.5 MW Cascade Solar project, SDG&E confirms that it "established an open, transparent and competitive process for the procurement effort."[113] The price to be paid by SDG&E was "[b]ased on Seller offer and adjusted by Time of Delivery ("TOD") factors as proposed in the RAM PPA."[114] In the case of Cascade Solar, the 2016 actual contract price, adjusted for TOD factors, was $75.13/MWh.[115]

These RAM projects were approved and built in the same time period that SDG&E was constructing its in-state utility-scale solar PPA projects.[116] Table 6 compares the unit cost of 2016 payments made by SDG&E to three RAM projects approved by the Commission in the second half of 2012 and first half of 2013 to the unit cost of SDG&E's 2016 payments to the 139 MW Campo Verde solar project, which uses First Solar panels and was approved by the Commission in mid-2012.

---

[109] RAM program: http://www.cpuc.ca.gov/Renewable_Auction_Mechanism/.
[110] *Id.*
[111] SDG&E, Advice Letters 2418-E and 2418-E-A, *Request for Approval of Standard Renewable Auction Mechanism Renewable Power Purchase Agreements with Cascade Solar LLC, ClearVista Energy LLC, MM San Diego LLC, Rugraw LLC and Supplemental Filing*, December 13, 2012, at p. 2.
[112] *Id.*
[113] *Id.* at p. 3.
[114] *Id.* at p. 7.
[115] SDG&E, A.17-06-006 D. Sullivan 2016 ERRA Compliance Testimony, June 1, 2017, at pdf p. 1030 and p. 1035. PPA terms: $64.81/MWh in 2013 escalating to $103.61/MWh in 2033 adjusted by TOD Factors. 2016 all-in energy price paid by SDG&E: $4,106,601 ÷ 54,660 MWh = $75.13/MWh.
[116] RAM program: http://www.cpuc.ca.gov/Renewable_Auction_Mechanism/.

Table 6. Comparison of actual unit cost of Campo Verde and RAM project(s) solar power[117]

Project	Capacity, MW	Date PPA signed	2016 production, MWh	2016 SDG&E payments, $	Unit cost of production, $/MWh
Campo Verde	139	May 2012	362,328	42,148,755	116.30
Cascade	18.5	Oct 2012	54,660	4,106,601	75.10
Calipatria	19.9	Dec 2012	47,438	3,541,070	74.60
Maricopa West	20	April 2013	52,566	3,403,504	64.70

All of the RAM PPAs were well under the MPR at the time. By contrast, many of the utility-scale solar and wind contracts entered into by SDG&E are above the applicable MPR.

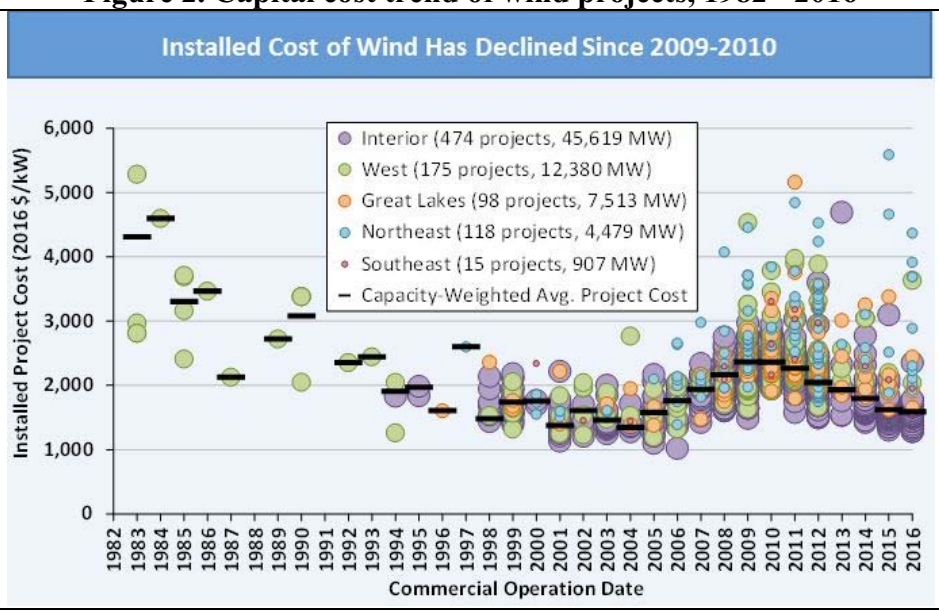
B. Wind Projects Case Study

SDG&E signed four in-state utility-scale wind power PPAs in the 2010-2012 time period that account for about 80 percent of SDG&E's contracted wind capacity. Three of these contracts were dramatically higher in price relative to those executed a few years before. The one exception is the 100 MW Manzana wind project. These four wind projects are discussed in turn below.

There was some increase in the cost of building wind projects between 2006 and 2013, on the order of 10 percent, as shown in Figure 2.[118] The COD of the 50 MW Kumeyaay wind project was 2006. The PPA price is $51.75/MWh.[119] If the same project had been built later with a COD of 2013, it is reasonable to assume that, holding other variables constant, the PPA price would increase by about 10 percent to approximately $57/MWh.[120]

[117] SDG&E, A.17-06-006 D. Sullivan 2016 ERRA Compliance Testimony, June 1, 2017, pdf pp. 1029-1031 and pp. 1034-1036.
[118] Average installed cost ~$1,800/kW in 2006, average installed cost ~$2,000/kW in 2013. Increase in installed cost = $2,000 kW ÷ $1,800/kW = ~10 percent. Data from Lawrence Berkeley National Laboratory webpage, accessed March 30, 2018: http://newscenter.lbl.gov/wp-content/uploads/sites/2/2017/08/wind_2016_image_2.jpg.
[119] SDG&E, A.17-06-006 D. Sullivan 2016 ERRA Compliance Testimony, June 1, 2017, pdf p. 1036. PPA terms: $49/MWh in Year 1 and escalating to $51.75/MWh in Years 5-20.
[120] $51.75/MWh x 1.10 = $56.93/MWh.

Figure 2. Capital cost trend of wind projects, 1982 - 2016[121]



The analysis that follows evaluates the four utility-scale wind project PPAs SDG&E entered into between 2010 and 2012. Comparison between them reveals that that prices of three of the four projects were known, or should have been known, to be well above market at the time they were approved by the Commission.

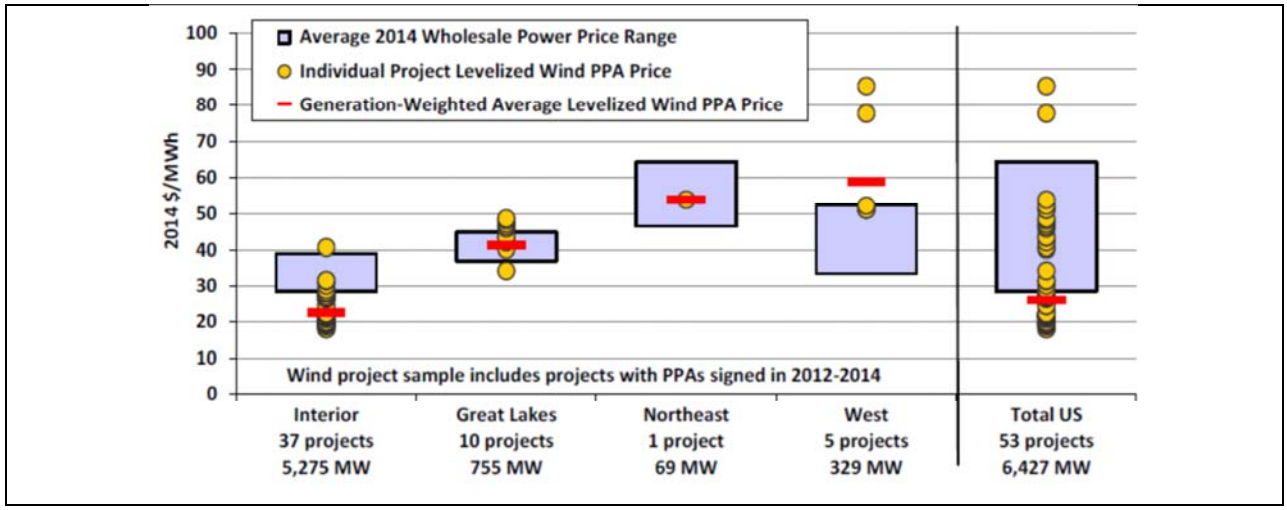
1. 265 MW Ocotillo Express

The 265 MW Ocotillo Express wind project is the largest project in SDG&E's portfolio at 265 MW and one of only four wind projects under contract over 100 MW. The installed capital cost of Ocotillo Express project of $2,088/kW,[122] as reported by SDG&E and with a COD of 2013, is approximately equal to the average installed cost of approximately $2,000/kW for wind projects reported by LBNL for wind projects with CODs in 2013.

Yet the average PPA contract price reported by NREL for wind projects with CODs between 2012 and 2014 was $60/MWh, compared to the $105/MWh price SDG&E pays for wind power from Ocotillo Express pursuant to its 2012 PPA and 2013 COD.[123]

[121] Lawrence Berkeley National Laboratory webpage, accessed March 30, 2018: http://newscenter.lbl.gov/wp-content/uploads/sites/2/2017/08/wind_2016_image_2.jpg.
[122] SDG&E, *California's Energy Future*, PowerPoint, 7th Annual Imperial Valley Renewable Energy Summit, March 12-14, 2014, p. 3 (public presentation).
[123] SDG&E, A.17-06-006 D. Sullivan 2016 ERRA Compliance Testimony, June 1, 2017, at pdf. p. 1036.

Figure 3. Average cost of wind power PPAs in West for projects with CODs in 2012-2014[124]



Despite these discrepancies, the Commission determined that the Ocotillo Express PPA would result in no above market cost burden on SDG&E ratepayers:[125]

Based on the 2012 commercial online date for the Ocotillo PPA, the 20-year PPA, as amended, is below the 2009 MPR. Thus, the Ocotillo PPA does not have any above-market costs.

The Commission's determination that the $105/MWh price tag for Ocotillo Express was not above market is contradicted by its evaluation of the 155 MW Sempra ESJ Wind project, discussed below. The Commission's 2012 resolution authorizing the ESJ contract determined that its price - $106.50/MWh, nearly identical to the Ocotillo price - was above market.[126]

2. 140 MW Pacific Wind

The 140 MW SDG&E Pacific Wind contract is a case study in unjustified PPA cost inflation. The initial PPA contract between SDG&E and Pacific Wind was approved by the Commission in 2006 for 205.5 MW at a contract price of $57/MWh,[127] identified by the Commission as below the 2004 MPR.[128] This 2006 contract price is consistent with SDG&E's

---

[124] Lawrence Berkeley National Laboratory, *2014 Wind Technologies Market Report: Summary*, August 2015, at p. 52.
[125] CPUC Resolution E-4458, January 12, 2012, at p. 9: http://docs.cpuc.ca.gov/word_pdf/FINAL_RESOLUTION/157540.pdf
[126] CPUC Resolution E-4467, March 22, 2012, at p. 29. "The ESJ PPA price of $106.50/MWh is above the applicable 2009 MPR." See: http://docs.cpuc.ca.gov/word_pdf/AGENDA_RESOLUTION/161368.pdf.
[127] SDG&E-Pacific Wind, LLC Power Purchase Agreement, October 12, 2005, at p. 6.
[128] Resolution E-3979, *SDG&E requests approval of the Pacific Wind renewable resource procurement contract. This contract is approved without modifications*, May 25, 2006, at p. 3. "On October 27, 2005, SDG&E filed Advice Letter (AL) 1734-E requesting Commission approval of one renewable procurement contract: Pacific Wind."

first in-state utility-scale wind PPA, the 50 MW Kumeyaay wind project. Kumeyaay came online in 2005 with a PPA price of $51.75/MWh.[129]

However, the Pacific Wind project was delayed, the PPA contract capacity adjusted downward to 140 MW to resolve local radar interference issues,[130] and the contract price increased from $57/MWh to $115.47/MWh.[131] The Commission noted in its September 2010 authorizing resolution for the Pacific Wind PPA that an independent engineer, R.W. Beck, had reviewed the project's original and revised financial proformas, and that the IE found Beck's analysis "credible and that the pricing of the amended and restated Pacific Wind PPA [was] reasonable in comparison to the market."[132] It concluded that the "amended and restated PPA is a bilateral contract for renewable generation that fits SDG&E's identified renewable resource needs."[133]

The case for Commission approval of the substantial increase in contract price rested largely on the R.W. Beck report. In its authorizing resolution, the Commission continues:[134]

> The Pacific Wind amended and restated contract price is above the market price referent (MPR) and is a new bilateral contract; thus, certain criteria outlined in E-4199 apply. . . As required, SDG&E explained why the contract change is needed and provided a showing which included relevant data and information to justify the change. . . Specifically, the amended and restated contract's price was compared to the projects that SDG&E is negotiating and to its most recent shortlist. Additionally, an independent engineer, R.W. Beck, reviewed the project's original and revised financial proformas. Specifically, R.W. Beck reviewed documentation from enXco showing the components of the price increase and reviewed data from other sources to confirm changes are reasonable from a market perspective."

POC requested the R.W. Beck report in a data request to SDG&E in an intent to understand the reasonableness of the Pacific Wind contract price increasing from $57/MWh to $115.47/MWh in less than five years. The R.W. Beck report was confidential Appendix H to SDG&E Advice Letter 2159-E, submitted to the Commission on April 30, 2010.[135] SDG&E responded to the POC data request stating that it did not have the R.W. Beck report.[136] This

---

[129] SDG&E, A.17-06-006 D. Sullivan 2016 ERRA Compliance Testimony, June 1, 2017, at p. DLS-22.
[130] CPUC Resolution E-4358, September 23, 2010, at p. 4: http://docs.cpuc.ca.gov/word_pdf/COMMENT_RESOLUTION/122269.pdf.
[131] SDG&E, A.17-06-006 D. Sullivan 2016 ERRA Compliance Testimony, June 1, 2017, at p. DLS-22.
[132] CPUC Resolution E-4358, September 23, 2010, p. 7.
[133] *Id.* at p. 8.
[134] *Id.* at pp. 6-7.
[135] SDG&E Advice Letter 2159-E, *Request for Approval of Third Amendment of Renewable Power Purchase with Pacific Wind, LLC*, April 30, 2010, at p. 5. Appendix H: RW Beck (IE) Price Increase Due Diligence. See: http://regarchive.sdge.com/tm2/pdf/2159-E.pdf.
[136] SDG&E Response to POC's Second Data Request in R.17-06-26, Response 9 at p. 10 (Mar. 16, 2018) ("SDG&E does not have the referenced report.").

response by SDG&E cannot be accurate, given the requested document is an attachment to an April 2010 SDG&E advice letter.

The dramatic price escalation of the Pacific Wind PPA in less than a five-year period is particularly striking when considered in light of the fact that the final amended PPA was executed only two years after the U.S. entered a major economic recession, which drove down equipment costs that had reached a post-2000 high point in 2008.[137]

3. 155 MW Energía Sierra Juarez

The 2012 SDG&E PPA with Sempra Generation for 155 MW of Energía Sierra Juarez ("ESJ") wind power in Mexico just over the border about 70 miles east of San Diego is an affiliate transaction. Affiliate transactions are subject to special reporting requirements by the Commission due to the potential hazard to ratepayers of IOUs contracting directly with their unregulated affiliates.[138] The sale by Sempra Generation of 556 MW Palomar Energy Center combined cycle project to SDG&E in 2006 was an affiliate transaction. The sale of 526 MW Desert Star Energy Center combined cycle project by Sempra Generation to SDG&E, in 2011, was also an affiliate transaction.[139]

Sempra Generation had made public statements prior to the 2012 signing of the ESJ PPA that it was developing projects in Mexico to take advantage of low labor costs, fast permitting, and less restrictive environmental laws.[140] Though Sempra Generation may have capitalized on a comparative lack of regulation and low labor costs in Mexico, the contract price for ESJ wind power, at $106.50/MWh, was more expensive than the $105/MWh contract for the Ocotillo Express project, sited in California about 100 miles east of San Diego.

4. 100 MW Manzana Wind PPA

SDG&E's 100 MW Manzana Wind PPA, with a contract price of $95/MWh,[141] is the sole utility-scale PPA it signed in the 2010-2012 timeframe that resulted in an actual contract payment in the range of the average PPA contract price for wind PPAs in the West for the 2012-2014 time period. SDG&E used a contract pricing formula unique among the utility-scale wind and solar contracts signed in the 2010-2012 timeframe. The average locational market price ("LMP") is subtracted from the contract energy price to arrive at a net payment price.[142] The net payment price in 2016 was $71/MWh. Although incrementally higher than the $60/MWh average wind PPA price for projects in the West

---

[137] Chemical Engineering (magazine), Chemical Engineering Construction Price Index (CEPCI), at p. 84, April 2012 edition. 2008 CEPCI = 575.4, 2010 CEPCI = 550.8.
[138] See SDG&E "Affiliate Transactions" webpage, accessed April 1, 2018: https://www.sdge.com/rates-and-regulations/other-regulatory-filings/affiliate-transactions.
[139] Resolution E-4465, August 2, 2012.
[140] Gas Turbine World, *Sempra Energy: Mexicali plant spurs surge of capacity*, at p. 36, April-May 2004.
[141] SDG&E, A.17-06-006 D. Sullivan 2016 ERRA Compliance Testimony, June 1, 2017, at p. DLS-21.
[142] *Id.*

in 2012-2014, the Manzana wind net price is much lower than the price paid by SDG&E for wind production from Pacific Wind, Ocotillo Express, and ESJ.

The Commission resolution approving the Manzana Wind PPA, was issued in August 2012. The Commission resolutions approving the Ocotillo Express and ESJ PPAs were issued in January 2012. These two PPAs are nearly 50 percent more expensive than the Manzana Wind PPA, as shown in Table 7.

Table 7. Actual price paid by SDG&E for wind power from Manzana Wind, Ocotillo Wind, and ESJ in 2016[143]

Project	Capacity, MW	2016 production, MWh	2016 SDG&E payment, $	Unit cost, $/MWh
Manzana Wind	100	283,511	20,180,686	71.2
Ocotillo Express	265	529,476	54,972,377	103.8
ESJ	155	423,308	44,282,091	104.6

SDG&E provides no explanation in its July 2017 ERRA testimony, which discussed the Manzana Wind contract structure, as to why it chose to use a pricing structure in the case of the Manzana Wind PPA that reasonably protects the interests of ratepayers but did not include this contract structure in two other large wind PPA contracts authorized the same year.

C. The IE and PRG are inadequate safeguards to assure PPA contracts are reasonably priced

The IE and PRG are an inadequate safety net to assure that SDG&E green power PPA contract pricing accords with LCBF principles. The excessively high cost of most of SDG&E's post-2008 utility-scale solar and wind contracts is testament to the inadequacy of the current contract review procedure. More rigorous scrutiny is particularly necessary in light of the self-dealing nature of much IOU procurement.

SDG&E's parent company is Sempra Energy. Sempra Renewables, an affiliate of Sempra Energy, has as its two largest solar clients PG&E and SCE.[144] These two IOUs have over 1,000 MW of solar capacity under contract with Sempra Renewables. As discussed above, SDG&E also heavily contracts with Sempra projects. Inflated solar PPA contract pricing directly benefits SDG&E's affiliate.

Neither the IE nor the PRG possess the independence or duty to safeguard load against self-dealing transactions. SDG&E used the same IE for all of its post-2008 in-state solar and wind PPAs, Jonathan Jacobs of PA Consulting. Mr. Jacobs was a PG&E executive, and PG&E

[143] SDG&E, A.17-06-006 D. Sullivan 2016 ERRA Compliance Testimony, June 1, 2017, at pp. 1030-1031 and pp. 1035-1036.
[144] See Sempra Renewables solar projects webpage: http://www.semprarenewables.com/energy-solutions/solar/solar-projects/.

affiliate company executive, for ten years prior to becoming a consultant. On his resume, he lists SDG&E and PG&E as primary clients.[145]

In addition, the IOUs have no obligation to address comments by PRG members, even if comments are received. This was underscored by SCE in the A. 14-11-012 evidentiary hearing,[146] during cross-examination of SCE witness Cushnie:[147]

> Q: Very good. And so how does it work? Is it evidentiary? Is it majority vote? If someone in the PRG says "I have an issue with how you structure your demand response contracts" for example, is there some formal process so that SCE incorporates that or does SCE just hear from someone on the PRG and you decide one way or the other whether you're going to incorporate or not that suggestion?
>
> A: So the Procurement Review Group process is a consultive process. There is no membership, per se. The entities that participate that are not Commission staff sign nondisclosure agreements. The Commission personnel participate under the Commission's confidentiality Public Utility Code requirements. And it is a process in which Edison as the utility puts forward its procurement recommendations and it seeks feedback from these participants. And it's an iterative process at times. It is certainly a dialogue. But at the end of the day, there's no vote taken. Edison takes the feedback that it gets under advisement, and then it moves forward.[148]

The PRG comes nowhere near the level of scrutiny achieved in an evidentiary process where independent parties can probe the validity of the facts at issue. The PRG process creates only the illusion of independent review.

VI. PCIA reliance on market value of resources is flawed and should be reformed.

The PCIA fundamentally conflicts with the objective that "bundled IOU customers should be neither worse off nor better off as a result of customers departing the IOU for other energy providers." The indifference concept imbedded in the current PCIA calculation is "indifference to the real-time market value of SDG&E's generation portfolio" using various PCIA assumptions regarding the market value of brown power, capacity, and green power, and not price indifference to the generation charge that SDG&E customers actually pay.

As a consequence, the PCIA currently enables IOUs to shed over-priced contracts, allowing them to reduce generation charges for bundled customers while placing the above-market component of those projects on the backs of departing load. That is, it effectively requires

[145] J. Jacobs resume.
[146] A.14-11-012, Evidentiary Hearing, May 6, 2015,Volume 2 at pp. 323-324.
[147] B. Powers, A.14-11-012 Opening Brief of Powers Engineering, June 10, 2015, pp. 8-9.
[148] Testimony of Colin Cushnie, A.14-11-012, Application of Southern California Edison Company (U 338-E) for Approval of the Results of Its 2013 Local Capacity Requirements Request for Offers for the Western Los Angeles Basin.

departing load customers to subsidize non-departing load customers in a "treadmill" effort to have non-departing load generation charges track current real-time market value rates of brown power, capacity, and green power. The PCIA thus enables a substantial reduction in the generation charge paid by non-departing load relative to what non-departing load actual pays now. This is not cost indifference. This is a cost subsidy by departing load to non-departing load customers.

The PCIA must be fundamentally reformed to meet the Commission's objectives and guiding principles. The average SDG&E retail generation charge in 2015 and 2016 was approximately $0.10/kWh, or $100/MWh. The indifference concept, applied to SDG&E customers in 2018, means non-departing load customers should not be subject to a generation charge greater than ~$100/MWh. Brown power CAM project costs should be passed through directly and not added to the PCIA. Any SDG&E green contract obligation under $100/MWh should not contribute to the PCIA, as it is at or below the generation charge that SDG&E customers currently pay.

At the same time, the Commission should adjudicate what portion of the price of high cost solar and wind contracts was reasonably avoidable, and it should instruct the utilities to absorb this cost. The Commission can use the market price referent and/or RAM contract pricing as a benchmark for evaluating this avoidable component. No SDG&E solar or wind contract that was significantly above the applicable market price referent (or the benchmark set by RAM contract pricing) was reasonable at the time it was signed. The contract terms were confidential and subject to little arms-length scrutiny. The Commission accepted, with its 2009 approval of the 10 MW El Dorado Solar PPA between PG&E and Sempra Generation, that PPA terms were subject only to qualitative weighing based on the IOU's expertise, effectively nullifying the primacy of LCBF as a deciding factor in bid selection and opening the door to the IOUs contracting for solar and wind at virtually any price for any reason.

The upshot of this analysis is that the PCIA, rather than escalating in price, should be approaching zero. The removal of brown power CAM projects will eliminate one of the most significant slices of the PCIA, and the upcoming ineligibility of wholesale brown power contracts will eliminate another slice. Adoption of the average generation charge as the MPB eliminates the vast majority of green power contracts. Solar contracts being signed by SDG&E under demonstrably more transparent contracting regimes, like the RAM standard offer auction mechanism, were signed at substantially lower cost than $100/MWh. As a consequence, most costs above $100/MWh on any SDG&E solar or wind contract should be borne by shareholders.

985039.9

Decision 18-10-019 October 11, 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

TABLE OF CONTENTS

Title **Page**

DECISION MODIFYING THE POWER CHARGE INDIFFERENCE ADJUSTMENT METHODOLOGY 1
1. Summary 2
2. Background 4
1.1. Procedural Background 10
3. Issues Before the Commission 12
2.1. Proposals 16
2.1.1. Joint Utilities: Green Allocation Methodology and Portfolio Monetization Mechanism 16
2.1.2. AReM/DACC 17
2.1.3. CalCCA 18
2.1.4. Commercial Energy 20
2.1.5. TURN 23
4. Framework for Preparing this Decision 25
3.1. Statutory Framework 26
3.2. Evidentiary Standards, the Burden of Proof, and the Burden of Production 30
5. Cost Shifts Under the Current Methodology 32
4.1. "Brown Power" Market Price Benchmark 34
4.2. RA Capacity Value 36
4.3. Renewable Resources 38
4.4. The Costs at Issue in this Proceeding 39
6. Scope of PCIA-Eligible Resources and Costs 44
5.1. Legacy Utility-Owned Generation 45
5.1.1. Positions of the Parties 45
5.1.1. Discussion 51
5.2. 10-Year Limitation on Recovery of Post-2002 UOG Costs 54
5.3. 10-Year Limitation on Recovery of Energy Storage Resource Costs 60
7. Adopted Portfolio Valuation and Allocation Methodologies 61
6.1. Positions of the Parties 62
6.2. Discussion 72
6.2.1. Revised Methodology for Calculating the Market Price Benchmark 73
7.2.1.1. New Reporting Requirements 74

TABLE OF CONTENTS
Con't

Title **Page**

6.2.2. Annual True-up 79
6.2.3. Caps, Floors, Collars and Sunsets 80
7.2.1.2.6.2.3.1. Sunset of the Obligation to Pay the PCIA 80
7.2.1.3.6.2.3.2. Should the Commission "Cap" the PCIA rate? 82
6.2.4. Prepayment 88
6.2.5. Review of Other Proposals 92
7.2.1.4.6.2.5.1. Joint Utilities 92
7.2.1.5.6.2.5.2. CalCCA 96
8. 7 Phase 2 of this Proceeding: Portfolio Optimization and Cost Reduction 96
7.1. General observations 97
7.2. Forecasting 104
7.3. Optimization 106
7.4. Securitization 107
7.5. Buydown/buyout 110
7.6. Discussion 111
9. 8. Other Issues 117
8.1. Tariffs and Bill Presentation 117
8.2. Remaining Issues 119
10. 9. Implementation 120
9.1. Calculation of the Revised PCIA 120
9.2. Rate Design 122
9.3. Annual True-up 124
11. 10. Conclusion: The Guiding Principles 127
12. 11. Comments on Alternate Proposed Decision 130
13. 12. Assignment of Proceeding 153
14. Findings of Fact 153
15. Conclusions of Law 156
ORDER 159

Appendix 1 Revised Formula for the Power Cost Indifference Adjustment (PCIA) Market Price Benchmark (MPB)

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 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.); codified at Water Code section 80000.

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 AB 117, which authorized the creation of Community Choice Aggregators (CCAs). CCAs are governmental entities formed by cities, counties, or a

---

[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.

combination of cities and counties, 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 investor-owned utility (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[8] and 366.3[9] 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:[10]

---

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

[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.

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

[10] Stats. 2015, ch. 547.

These statutory developments 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.[11] 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].[12]

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 decision. First, D.11-12-018 adopted a revised capacity adder and increased the market price benchmark by adding a renewable procurement standard (RPS)

---

[11] *See,* D.06-07-030.

[12] *Id.* at 25.

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.[13]

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.[14] 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.[15] The working group met a number of times and submitted its final report on April 5, 2017.[16] Many of the participants in the working group are parties in this rulemaking.

---

[13] D.14-10-045, Ordering Paragraph 1.

[14] D.16-09-044 at 19.

[15] *Id.*, at 20 and Ordering Paragraphs 7 and 8.

[16] 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

Footnote continued on next page

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.[17] 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 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

---

common PCIA calculation workpaper template in the IOUs' ERRA Forecast proceedings. The Commission adopted this template in D.17-08-026.

[17] 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.

(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.[18] That motion is hereby granted.

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 (CSD), the California Manufacturers & Technology Association (CMTA), EPUC, the Independent Energy Producers Association (IEP), Los Angeles Community Choice Energy (LACCE), Coachella Valley Association of Governments (CVAG) and the Western Riverside Council of Governments (Joint CCAs), Joint IOUs,

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

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.[19]

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.

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?

[19] 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.

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?[20]
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.

[20] 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 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.

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.

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 "derived from statutory instructions, prior Commission decisions, and participation of a variety of stakeholders in other proceedings and Commission forums.":[21]

[21] Scoping Memo at 11.

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;
   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 (PPAs) 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 Electric Service Provider (ESP), those benefits and costs follow the customers to their new Load Serving Entity (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."[22]

Under GAM, the Renewables Portfolio Standard (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, ancillary service (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 Renewable

[22] Joint Utilities opening brief at 43.

Energy Credit (REC) attributes of those resources are allocated pro rata to the LSEs serving departing load customers.[23]

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 immediately implementable and scalable for all potential levels of departing (and returning) load."[24]

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 Platts Portfolio Content Category (PCC) 1 REC indices; and (3) a revised capacity adder should be developed that

[23] *See*, Section 6.1, *infra*, for further discussion.

[24] Joint Utilities opening brief at 42-43.

is "tied to a Commission determination as to whether new capacity resources are needed within the next three years:"[25]

- 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."[26] CalCCA's fundamental point is that long-term resources should be valued using long-term valuation measures:

> 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.[27]

CalCCA contends that "the Joint Utilities underestimate the value of the bundled portfolio by failing to recognize valuable attributes and ignoring

---

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

[26] CalCCA opening brief at 10.

[27] CalCCA opening brief at 42, citing Pub. Util. Code § 366.2(f)(2) and § 366.2(g).

long-term portfolio characteristics and value."[28] 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;
- Adding a component to account for the value of greenhouse gas (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 Department of Energy (DOE) value component.

In order to correct the cost side of the equation, CalCCA proposes to remove Legacy Utility-Owned Generation (UOG) costs from CCA cost responsibility.

[28] *Ibid.*

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.[29]

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,

[29] CalCCA opening brief at 9.

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 (CTAs):

> 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.[30]

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

[30] Commercial Energy opening brief at 4.

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 RA and RECs 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."[31] 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."[32]

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' standard, while taking other steps toward longer-term reforms (we discuss the latter proposals below).[33]

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

---

[31] *Id.* at 5.

[32] *Ibid.*

[33] Exhibit TURN-2 at 2.

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.[34]

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."[35] 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.[36]

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 market price benchmark (MPB).[37]

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

---

[34] Exhibit TURN-1 at 9.

[35] *Ibid.*

[36] *Id.*, footnote 22.

[37] Exhibit TURN-1 at 9.

> 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.[38]

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.[39] TURN makes this recommendation based on its observation that "current, annually-fluctuating PCIA charges complicate individual 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."[40]

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.

---

[38] TURN opening brief at 15, citing Exhibit TURN-1 at 8-10.

[39] Exhibit TURN-1 at 11.

[40] *Ibid.*

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 in order to establish the necessary context for the findings and conclusions we reach in this decision.

In CalCCA's view "the Legislature has tasked the Commission with ensuring the success of its vision"[41] and in realizing that vision, the Commission must do the following (we have replaced CalCCA's paraphrasing with statutory language so as to provide a more 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 SB 790 establish a code of conduct, associated rules, and enforcement procedures, applicable to electric utilities "in order to facilitate the consideration, development, and implementation of CCA programs, to foster fair competition, and to protect against cross-subsidization by ratepayers;"

[41] *Id.* at 4.

- 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 an electrical corporation;"[42]
- Adhere to the requirement of § 366.2(a)(5) 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,

    > (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."

[42] 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."

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

CalCCA also calls attention to the wording of Sections 366.2(f) and (g):[43]

(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 <u>estimated net unavoidable electricity purchase contract costs attributable to the customer</u>, as determined by the commission, for the period commencing with the customer's purchases of electricity from the community choice aggregator, through the expiration of all then existing electricity purchase contracts entered into by the electrical corporation.

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

The Scoping Memo's guiding principles acknowledge that any methodology adopted by the Commission to prevent cost shifting for either bundled or departing load "should allow alternative providers to be responsible

[43] Emphases added.

for power procurement activities on behalf of their customers, except as expressly required by law."[44]

We note that there are already topics for which the Legislature has directed this Commission to be involved in a CCA's generation procurement activities. Examples include:

- Resource Adequacy;[45]
- Renewables Portfolio Standard;[46]
- Bioenergy;[47]
- Integrated Resource Planning;[48] and
- Energy Storage.[49]

CalCCA cites one of the legislative findings and declarations at the beginning of SB 790, adopted by the Legislature in 2011:[50]

---

[44] Scoping Memo at 14, Guiding Principle 1.f.

[45] Pub. Util. Code § 380(e), "Each load-serving entity shall be subject to the same requirements for resource adequacy and the renewables portfolio standard program that are applicable to electrical corporations pursuant to this section, or otherwise required by law, or by order or decision of the commission. The commission shall exercise its enforcement powers to ensure compliance by all load-serving entities."

[46] Pub. Util. Code § 399.12(j)(2), "A community choice aggregator shall participate in the renewables portfolio standard program subject to the same terms and conditions applicable to an electrical corporation."

[47] Pub. Util. Code § 399.20.3(f), "The commission shall ensure that the costs of any contract procured by an electrical corporation to satisfy the requirements of this section are recoverable from all customers on a nonbypassable basis."

[48] Pub. Util. Code § 454.51(d), "If the commission finds this need is best met through long-term procurement commitments for resources, community choice aggregators shall also be required to make long-term commitments for resources."

[49] Pub. Util. Code § 2838(a)(2), "By January 1, 2021, each load-serving entity shall submit a report to the commission demonstrating that it has complied with the energy storage system procurement targets and policies adopted by the commission pursuant to subdivision (a) of Section 2836."

> 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.[51]

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."[52] By juxtaposing § 451 and § 366.2(f)(2) CalCCA asserts that "consequently, the Commission must ensure that the utilities minimize portfolio costs for all customers and exclude avoidable costs from recovery through the PCIA."[53]

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

---

[50] 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, whichAuthority, which launched California's first Community Choice Aggregation program, Marin Clean Energy.

[51] Stats. 2011, Ch. 599 Sec. 2(h) (emphasis added).

[52] CalCCA opening brief at 10, citing § 366.2(f)(2).

[53] *Ibid.*

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."[54] 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'."[55] In short, in typical ratesetting proceedings the applicant must present more 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 double regarding the utility's position, the utility has not met its ultimate burden of proof.[56]

---

[54] Pub. Util. Code § 454.

[55] *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).

[56] D.87-12-067, 27 CPUC2d 1, 22.

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.

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:

Formula:	*Definition of terms:*
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:

Total Portfolio Costs – Market Value of Portfolio = 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 Combined Heat and Power 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.[57]

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 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)."[58]

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" MPB.

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."[59] CLECA recommends that no revision to this benchmark is necessary. AReM/DACC's

---

[57] Exhibit TURN-1 at 5.

[58] *Ibid.*

[59] CLECA opening brief at 9, citing Exhibit TURN-2 at 4.

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 be reasonable and that market forwards, taken as close to the end of the year as practical, should continue to be used."[60]

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.[61]

We do not dismiss the analysis and contentions of POC and other parties regarding the question of whether the current benchmarks completely capture

---

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

[61] POC opening brief at 6, citing the following:

- D.07-01-030 at 13; Exhibit AD-01 at 9;
- Reporter's Transcript (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).

the long-term value of portfolio resources. At the same time, these parties have had difficulty proving that this is the case. We are left to base our 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."[62] 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."[63]

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."[64] TURN speaks for most parties in stating that this estimate "has very little

---

[62] Exhibit TURN-1 at 6.

[63] *Ibid.*

[64] *Ibid.*, citing Commission Resolution E-4475, Exhibit A at 2.

relationship to the actual market prices at which all LSEs buy and sell RA capacity."[65] TURN cites the following examples:

- 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:[66]
  - 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.[67]

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."[68]

---

[65] *Ibid.*

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

[67] *Ibid.*, and Attachment C to Exhibit TURN-1.

[68] *Id.* at 7.

4.3. Renewable Resources

TURN also claims the data used to estimate the market benefits of the IOU renewable resources are inadequate, because they "do not reflect the actual benefits an IOU would earn selling such resources in the market."[69]

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).[70] 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."[71]

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."[72] Second, TURN notes that the DOE has

---

[69] *Ibid.*

[70] *Ibid.*, citing Commission Resolution E-4475, Exhibit A.

[71] *Ibid.*

[72] *Id.* at 8, emphasis added.

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."[73]

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 Memo also drew a distinction between "revisiting" prior Commission

[73] *Ibid.*

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.[74] 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.[75]

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.[76] We summarize information from those responses below. We also acknowledge that not all parties agree with the responses provided by the Joint Utilities.

---

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

[75] November 22, 2017 Ruling Confirming Scoping Memo Issues at 10.

[76] Exhibit IOU-5.

Again, our purpose here is to establish context showing the magnitude of the challenges we are addressing in this decision.[77]

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.[78]

2. How has the PCIA rate changed over time?

   The Joint Utilities provide the following response to this question:

   > 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

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

[78] Exhibit IOU-1 at 1-10 to 1-11.

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?

In response to this question, the Joint Utilities simply cite 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 additional 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.[79]

Commercial supports its recommendations with the following summary of the data in Exhibit IOU-5:

- 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.

[79] Commercial Energy opening brief at 6-7.

- 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."[80]

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.

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.[81] Third, CalCCA opposes proposals in this proceeding to exempt

---

[80] CalCCA opening brief at 1, quoting Exhibit CalCCA-1 at 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.

[81] "Legacy" UOG is utility-owned generation installed before 2002.

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.

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

5.1.1. Positions of the Parties

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."[82] The Commission responded by establishing the "Competition Transition Charge" and stated "[w]ith 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."[83]

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"[84] and, "[m]oreover, the Legislature made clear its

[82] Cal. Pub. Util. Code §367.

[83] D.95-12-063 at 119.

[84] CalCCA opening brief at 31.

intent *not* to recover the costs from CCA departing load customers in AB 117."[85] CalCCA contends that the Legislature "carefully prescribed the scope of costs that must be recovered from CCA departing load to prevent a cost shift to bundled customers."[86] These costs are listed as:

- 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.[87] Finally, CalCCA asserts that no statute passed since that time has imposed Legacy UOG costs on CCAs or any other departing load customer class.[88]

CalCCA relies on "a well-settled canon of statutory interpretation in California law" to support its position: *Expressio unius est exclusio alterius* – "the

[85] *Ibid.*

[86] *Ibid.*

[87] *Ibid.*

[88] *Ibid.*

expression of one thing implies the exclusion of others."[89] CalCCA argues that, because the Legislature specified in AB 117 the costs that were to be borne by 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.[90]

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 the led to Commission decisions to include utility generation in departing load charges, and seeks to demonstrate 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.[91] 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.[92] 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.

---

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

[90] *Ibid.*

[91] CalCCA opening brief at 33, citing D.02-11-022 at 23.

[92] *Ibid.*, citing D.08-09-012 at 49-52.

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 consistently uneconomic, contributing $545 [million] in uneconomic costs to PG&E's 2018 PCIA."[93]

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."[94] 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.'[95]

---

[93] *Id.* at 34.

[94] *Id.* at 35-36.

[95] *Id.* at 36. Section 728 provides, in pertinent part, "[w]henever 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."

The Joint Utilities' oppose CalCCA's proposal. First, the Joint Utilities assert that "if the Legislature wanted to exclude Legacy UOG 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.[96]

The Joint Utilities argue that the fact that Legacy UOG was not listed in Section 366.2(f) is immaterial because the Legislature did not specifically exclude Legacy UOG, 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 electricity purchases. Legacy UOG, by definition, is not a prospective "generation procurement arrangement."[97]

---

[96] Joint Utilities reply brief at 84.

[97] *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

Footnote continued on next page

Third, the Joint Utilities assert that CalCCA's reliance on *expressio unius est exclusion 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 **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.[98]

---

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 Examiner*s, 17 Cal.4th 763, 776 (1998)].

[98] *Id.* at 86.

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."[99]

CLECA asserts that "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."[100]

TURN, on the other hand, considers Legacy UOG a category of "additional costs of the electrical corporation recoverable in commission-approved rates."[101] TURN further points to the cost shifting prohibitions in AB 117 and elsewhere as explicit provisions that prevent consideration of CalCCA's proposal to prevent cost recovery for Legacy UOG from CCA customers.[102]

5.1.1. Discussion

Regarding Legacy UOG, we find the statutory arguments offered by CalCCA to be unconvincing: the Legislature provided, both in AB 117 and SB 350, that we should prevent cost shifts between customers as a result of customer departure. CalCCA would have us infer not only that the Legislature's list of costs for which a CCA customer "shall reimburse the electrical corporation

---

[99] *Id.* at 86.

[100] CLECA reply brief at 3.

[101] TURN reply brief at 11 (citing Pub. Util. Code §366.2(f)(2).

[102] TURN reply brief at 12.

that previously served the customer"[103] is exclusive, but also that Section 366.2(f) overrides the Legislature's direction "to prevent any shifting of recoverable costs between customers."[104] That position would read part of Public Utilities Code Sections 366.2(f) and 365.2[105] out of the law.[106] Such a reading of Section 366.2(f) would render the statute inconsistent with its own subdivision (g), thus violating the "cardinal rule of statutory construction that . . . a statute must be read and considered as a whole, in order that the true legislative intention may be determined."[107] In light of SB 350's cost shifting language, CalCCA's reading of Section 366.2(f) would also subordinate a later-in-time statute to an earlier-in-time one -- another conflict with the principles of statutory construction.[108] We do not read section 366.2(f) as an exclusive list of PCIA-eligible costs.[109]

---

[103] Pub. Util. Code §366.2(f).

[104] Pub. Util. Code §366.2(d)(1).

[105] Added by SB 350 (2015).

[106] *And see*, Pub. Util. Code §365.1(c)(2).

[107] *People v. Moroney* (1944) 24 Cal. 2d 638, 642. *See also*, *Clean Air Constituency v. State Air Resources Board*, 11 Cal.3d 801, 814 (1974) (courts "should construe every statute with reference to the entire scheme of law of which it is part so that the whole may be harmonized and retain effectiveness.").

[108] *See e.g.*, *People v. Moody* (2002) 96 Cal. App. 4th 987, 993.

[109] *Cf. Association of California Ins. Companies v. Jones* (2017) 2 Cal.5th 376, 398:

> Invoking the maxim *expression unius est exclusion alterius*, the Association contends that the Legislature's decision not to specifically designate incomplete replacement cost estimates as misleading statements must be viewed as a conscious choice by the Legislature. The Commissioner, in [the Association's] view, was therefore precluded from promulgating a regulation on the topic of replacement cost estimates. The Association has misconstrued the maxim as well as the interplay between the Commissioner and the Legislature. . . . [T]he fact that the Legislature

Footnote continued on next page

Prior Commission Decisions implementing AB 117 included legacy UOG as costs to be recovered from CCA customers.[110] And we permitted recovery of then-new UOG from all customers.[111] In addition, the Legislature elsewhere clearly contemplated and accepted that CCA customers could pay for UOG-related costs.[112]

> defined as unfair or deceptive a detailed list of specific unfair claims settlement practices . . . does not signal an intent to exempt any particular category of misleading statements from the broad prohibition on such statements in section 790.03, subdivision (b). [] Rather, it means only that the Legislature did not itself choose to specify the types of statements that *must* be deemed misleading and entrusted that determination instead to the Commissioner's expertise.

[110] D.04-12-046 at 24 ("AB117 requires the CCA CRS to include a variety of costs incurred on behalf of CCA customers prior to their transferring to the CCA. Such costs include . . . (2) utility power costs, including those of utility retained generation, purchased power and other commitments in approved resource plans.").

[111] D.04-12-048 at 229-30, COL 16.

[112] Pub. Util. Code §365.1(c)(2).

> [I]n the event that the commission . . . orders, in the situation of utility-owned generation, an electrical corporation to obtain generation resources that the commission determines are needed to meet system or local area reliability needs for the benefit of all customers in the electrical corporation's distrubution service territory, the net capacity costs of those generation resources are allocated on a fully nonbypassable basis consistent with departing load provisions as determined by the commission to all of the following:
>
> . . . .
>
> (iii) Customers of community choice aggregators.

Further, it would be anomalous to find that CCAs "do not appear to have similarly benefitted"[113] from Legacy UOG. Assets built to serve load that later departs was, of course, benefitting those customers.

We cannot find a principled justification to exclude those costs for CCA customers because they are now above-market. Exclusion of those above-market costs amounts to an invitation to shift costs to bundled customers that were incurred to serve CCA customers who later departed. We agree with TURN that AB 117 clearly intends to "prevent any shifting of recoverable costs between customers."[114] Recoverable costs clearly encompasses Legacy UOG in addition to PPAs.

Based on our review of the positions of the parties and their briefing of this issue, we conclude that the costs of Legacy UOG are within the scope of costs that can be allocated to CCA departing load customers.

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."[115] Therefore, the Joint Utilities contend that the 10-year limit must be

---

[113] CalCCA opening brief at 34.

[114] TURN reply brief at 11 (*quoting* Pub. Util. Code 366.2(d)(1)).

[115] Joint Utilities opening brief at 29.

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.

TURN shares the Joint Utilities' view, arguing that "[t]he key flaw in CalCCA's argument is the assumption that IOUs should have previously forecasted a wave of departing load that would effectively strand most of their supply portfolio."[116]

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 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.[117]

CalCCA also supports retaining the 10-year limitation, arguing that the Joint Utilities' "seeming inability to tailor a portfolio to reasonable expectations

---

[116] TURN reply brief at 13.

[117] 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.

over the past decade is not a sufficient reason to permit continued cost recovery."[118]

Neither Commercial Energy nor CalCCA adequately recognize that their policy position regarding alleged portfolio mismanagement of post-2002 UOG would simply place the burden of cost recovery solely on bundled customers after the 10-year limit expires. Portfolio optimization will be the subject of this proceeding's second phase; the task before us here is an equitable division of the portfolio costs incurred to serve customers who have since departed. Nearly 15 years have passed since the Commission established the 10-year limitation for Edison's Mountainview plant,[119] and revisiting the assumptions of a post-energy crisis Commission is warranted. Indeed, the first CCA started serving load more than five years after D.03-12-059.

In its 2004 decision implementing AB 117, the Commission stated:

> 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) <u>and promote good resource planning by the utilities</u>.[120]
>
> …
>
> We do not agree . . . that the CRS should exclude any energy commitments entered into following passage of AB 117. As long as the utilities have made reasonable assumptions about future electricity demand, the <u>CRS must include all stranded costs that occur when customers transfer their accounts to the CCA</u>. Although

[118] CalCCA reply brief at 9.

[119] D.03-12-059 at 32 (*see* TURN's opening brief at 13-14).

[120] D.04-12-046 at 29, emphasis added.

> some cities and counties have formed CCAs or expressed an interest in forming CCAs, the utilities have had little basis on which to forecast reductions in load that would occur as a result of AB 117.
>
> On the other hand, SCE's proposal to include in the (vintage) CRS all contract costs incurred up to the date customers transfer to the CCA is not consistent with the law. There will surely be circumstances where contracting for more energy, assuming all CCA load, would be 'avoidable' and where those commitments would not be 'attributable to the customer.'
>
> 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.[121]

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.[122] That

---

[121] *Id.* at 30.

[122] R.04-04-003, *Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning*.

decision also addressed the effect of departing load on utility procurement, noting that parties representing potential departing 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."[123] 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."[124] 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."[125] 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."[126]

---

[123] D.04-12-048 at 18.

[124] *Id.* at 57.

[125] *Id.* at 59.

[126] *Id.*, Ordering Paragraph 9.

PG&E's Humboldt plant illustrates the peril of imposing post-2002 UOG on bundled customers alone after 10 years. The Humboldt plant was built for local reliability.[127] The local area now includes a CCA. With a ten year limitation on post-2002 UOG eligibility for the PCIA, customers in the local area who now take service from a CCA would be exempt for paying for a power plant built for their own local reliability needs. Meanwhile, customers in Bakersfield or Stockton—who have no choice but to stay with the utility—would pay for that plant's above-market costs.

The parties seeking to retain the 10-year limit have suggested that it creates an incentive for IOU portfolio management and that ten years is sufficient time for utilities to adjust their portfolios to reflect load changes.[128] As noted by TURN, assigning the financial consequences of these resources to bundled customers does not "hold IOUs accountable for poor performance,"[129] it punishes bundled customers.

Recognizing that parts of the IOU portfolio are in excess of bundled customers' needs, phase two of this proceeding will work toward portfolio optimization and cost reduction. But the cost allocation mechanism we establish here must equitably distribute stranded costs among customers for whom those costs were incurred. We see no justification to continue a 10-year limit on recovering costs for post-2002 UOG from departing load—a limitation that does not exist for either post-2002 PPAs or for pre-2002 UOG.

---

[127] TURN PD comments at 7 (*citing* D.06-11-048 at 8).

[128] *See*, *e.g.*, AReM/DACC APD comments at 12.

[129] TURN PD comments at 8.

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

The Joint Utilities make similar arguments to eliminate the 10-year limitation on recovery of PCIA-eligible energy storage costs as they made in support of elimination of the more general 10-year limitation on recovery of post-2002 UOG. In D.14-10-045, the Commission placed a 10-year limitation on PCIA cost recovery on resultant energy storage contracts in recognition of the nascent state of the market, and of the need to further develop the methodology for establishing above-market costs of energy storage projects.[130] As part of the decision, the Commission also directed the IOUs to file an Application for a proposed "Joint IOU Protocol" to determine the above-market stranded cost of bundled service storage for inclusion in the PCIA, concluding that other venues such as workshops or OIRs should be considered to help resolve the outstanding PCIA treatment issues.[131] The Joint IOU Protocol was later addressed through adoption of D.16-09-004, which approved a method for incorporating the costs and value of energy storage contracts into the calculation of PCIA rates, but did not reconsider the 10-year PCIA limitation.

Similar to the conclusions above regarding post-2002 UOG costs, we find that PCIA-eligible energy storage resources should be treated in the same manner as other resources in the IOU portfolio and should not be subject to a 10-year limitation on cost recovery. We reach this conclusion for several reasons.

First, as we found in the preceding section, customer indifference requires the equitable distribution of all stranded costs among customers for whom those

---

[130] D.14-10-045 at 88.

[131] *Id.*, Conclusions of Law 31 and 32.

costs were incurred. Portfolio optimization and cost reduction will be the focus of phase two of this proceeding.

Second, the Commission's decision to impose a 10-year limitation on PCIA cost recovery for the initial 2014 storage solicitation was predicated on the nascent stage of the market, and the need to further develop the above-market costs and value of energy storage projects to incorporate into the PCIA calculation. Since that time, the Commission has adopted a methodology for incorporating above-market energy storage costs and values into the PCIA calculation, while the energy storage market has grown considerably, with a total amount of Commission-approved and currently pending energy storage applications under review exceeding the 1.325 gigawatt Energy Storage Procurement target established in D.13-10-040.[132] For all of these reasons, we conclude that PCIA-eligible energy storage resources will not be subject to a 10-year limitation on cost recovery.

6. Adopted Portfolio Valuation and Allocation Methodologies

In this section, 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

[132] Progress towards the 1.325 gigawatt energy storage target is reported on the Commission's energy storage webpage, here: http://www.cpuc.ca.gov/general.aspx?id=3462.

> 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 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: 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 to ensure that any forecast-related errors in the annual PCIA are reconciled and cost-shifting is prevented.

6.1. Positions of the Parties

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."[133] As CalCCA's securitization proposal, AReM/DACC would support Commission direction to consider the VAAC 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.

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:"[134]

> 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.[135]

---

[133] AReM/DACC opening brief at43-44.

[134] CalCCA opening brief at 8.

[135] *Ibid.*

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.[136] 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 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.[137]

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

---

[136] Commercial Energy opening brief at 2.

[137] *Ibid.*

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."[138] 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 argues 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 states that the Joint IOU proposal to allocate unbundled RECs to satisfy certain RPS requirements is not consistent with the law or Commission policy. CUE offers no means of reconciling this problem in time to implement the GAM/PMM in 2019.[139]

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."[140]

---

[138] CUE opening brief at 17.

[139] *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.

[140] CMTA opening brief at 6.

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

The CSD asserts that the Joint Utilities have not met their burden with respect to the GAM/PMM proposal, so it should not be adopted. In addition, CSD 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."[141] For these reasons, CSD recommends that PCIA reform begin with "relatively simple changes to the PCIA" identified by AReM/DACC and others.[142] For CSD, 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 assert it is the best alternative to the current PCIA because it addresses customer indifference through a modified status quo, with the ability for long-term re-structuring 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.

---

[141] CSD opening brief at 8, citing Exhibit AD-02 at 23-24 (Compare Figures 2 and 4 to Figure 3).

[142] *Id.* at 9.

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."[143]

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

> 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.[144]

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.[145] 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."[146]

---

[143] 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.

[144] ORA opening brief at 13.

[145] *Id.* at 9-12.

[146] *Id.* at 6.

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.[147] 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 where contract rights cannot be assigned.[148] 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 states 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.[149]

---

[147] POC opening brief of at 26, citing Exhibit UCAN-01 at 9.

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

[149] POC reply brief at 5.

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."[150] UC support the types of incremental changes proposed by AReM/DACC and oppose the Joint IOUs' GAM because it is inconsistent with and disruptive to UC's Portfolio Management Strategy:

> 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.[151]

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."[152] For Shell, then, a key consideration in the PCIA

---

[150] UC opening brief at 5.

[151] *Id.* at 7.

[152] Shell Energy opening brief at 3-4, citing Exhibit CalCCA-l at 2A-1.

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 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.'[153]

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.[154]

SEA recommends that the Commission retain the existing PCIA framework with necessary modifications, instead of adopting the GAM and PMM proposals. SEA 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. SEA raises concern that the GAM and PMM proposals are new and untested; like CSD Diego, SEA 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

---

[153] *Id.* at 4, citing Exhibit CalCCA-1 at 2A-4.

[154] *Id.* at 5.

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."[155]

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 GAM 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;

---

[155] SEA opening brief at 8. SEA 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 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."

3. RECs;
4. option and hedge value; and
5. a long-term GHG adder.

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 the inputs thereto, while opening 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 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 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 9 below.

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, in the beginning of November each year.

Second, we adopt TURN's approach for estimating the RPS Adder. We appreciate TURN's frank acknowledgement of 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 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").[156] 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).[157] A zero or *de minimis* price shall be assigned for capacity expected to remain unsold.[158] As with the RPS Adder, we find that TURN's approach to reconciling limited

---

[156] Exhibit TURN-1 at 9.

[157] *Ibid.*

[158] *Id.* at 10.

sources of transparent price data and developing as accurate an estimate as possible is credible.

We also adopt CLECA's proposal that the RA Adder be changed to reflect the three types of RA capacity: system, local, and flexible.[159]

- 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.

[159] 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.

6.2.1.1.1. Positions of the Parties

AReM/DACC, Shell and Commercial Energy take the position that the Commission cannot require ESPs or CCAs to reveal contract/price information.[160] These parties make two primary arguments; section 380(f) limits the information the Commission can require from the ESPs and CCAs, and section 394(f) prevents the Commission from regulating the rates ESPs charge or are paid.[161] Section 380(f) provides:

> The commission shall require sufficient information, including, but not limited to, anticipated load, actual load, and measures undertaken by a load-serving entity to ensure resource adequacy, to be reported to enable the commission to determine compliance with the resource adequacy requirements established by the commission.

Section 394(f) provides:

> Registration with the commission is an exercise of the licensing function of the commission, and does not constitute regulation of the rates or terms and conditions of service offered by electric service providers. Nothing in

[160] AReM/DACC, comments on PD p. 8; AReM/DACC, comments on APD p. 10; Shell Energy comments on PD, pp. 4-6; Commercial Energy, comments on PD, pp. 4-6.

[161] Ibid.

> this part authorizes the commission to regulate the rates or terms and conditions of service offered by electric service providers.

Discussion

AReM/DACC, Shell and Commercial Energy's arguments fail for several reasons. Mostly they conflate the Commission's inability to set their prices with our duty to collect that price information. This Decision makes clear that the cost information will be used as part of setting a departing fee charge; it does not attempt to set any price or cost metrics or parameters for ESPs. The argument, moreover, ignores our comprehensive jurisdiction and statutory responsibilities and that the information is already required to be provided to the Commission.

The Commission has jurisdiction over long term procurement of energy resources that will supply energy service when and where needed.[162] The Commission is also charged with developing Demand Response products encouraging distributed generation.[163] This jurisdiction is so comprehensive that it includes questions of public health and safety arising from our duty to assure that customers receive adequate utility services at just and reasonable rates and justifies our direction that LSEs must provide the information to the Commission. (See Cal. Const, Art. 12; Public Utilities Code §451; *P.G.&E. Corporation v. Public Utilities Commission* (2015) 237 Cal.App.4th 812.)

In addition to that comprehensive jurisdiction, this Commission is obligated to study the RA market and to report to the legislature costs relating to the RPS program. Public Utilities code section 380(b)(1) requires the Commission to:

---

[162] Pub. Util. § 454.5, et seq.

[163] Pub. Util. § 380, § 769.

> (b) In establishing resource adequacy requirements, the commission shall achieve all of the following objectives:
>
> > (1) Facilitate development of new generating capacity and retention of existing generating capacity that is economic and needed.

The Commission needs price information to understand the RA market in furtherance of "[f]acilitating development of new generating capacity and retention of existing generating capacity" in addition to maintaining needed existing resources that will dispatch pursuant to a Resource Adequacy must offer obligation or economically bid into CAISO markets. Because the information sought by this Decision is needed to satisfy the Commission's obligation to comply with section 380(b)(1), among other obligations, the ESPs and CCAs already have a duty to provide it.

These same parties are also required to provide RPS cost data to enable "the commission [to] release to the Legislature for the preceding calendar year the costs of all electricity procurement contracts for eligible renewable energy resources, … ."[164] More specifically, the "Director of Energy Division is authorized to require retail sellers to submit appropriate documentation, <u>including but not limited to copies of renewables portfolio standard procurement contracts</u>, to support the information in any report submitted."[165] And the Director of Energy Division has, in fact, required submission of those contracts.[166] Again, given the information sought by this Decision is needed to satisfy the

---

[164] Pub. Util. §913.3(a).

[165] D.12-06-038, Ordering Paragraph 41, emphasis added.

[166] See, *Portfolio Content Category Classification Review Process Handbook*, p. 8, available at: http://cpuc.ca.gov/General.aspx?id=3856 [4th link down the page].

Commission's obligation to comply with the RPS program, among other obligations, the ESPs and CCAs already have a duty to provide this information.

Contrary to the position that the Commission has no jurisdiction to obtain pricing information or is attempting to "expand [the Commission's] regulatory control over the activities of ESPs," the duties imposed on the Commission are separate and apart from a CCAs' or ESPs' ability to set their own prices paid or charged. In other words, the Commission's requiring the data, and the ESPs' and CCAs' providing the data, has nothing to do with setting ESPs' or CCAs' retail rates. Actual contract prices provide the most accurate and timely indications of current and forward energy supply conditions, which are clearly within the Commission's jurisdiction to require.

Based on the Commission's comprehensive jurisdiction over the state's long term energy supply portfolio, AReM/DACC, Shell and Commercial Energy's position that the Commission cannot require ESPs or CCAs to reveal contract/price information is requires a crabbed and incomplete reading of the Public Utilities Code.

The confidentiality concerns expressed by Shell, Commercial Energy and AReM/DACC have already been addressed in the Commission's discussion of the public's need for this information balanced with the LSE's need to protect market sensitive data. As we said in the past:

> All reports and information required to be submitted to the Director of Energy Division by this [RPS] decision, including any supplemental material requested by the Director of Energy Division, is submitted subject to the Commission's confidentiality rules. … We noted in D.06-06-066 that, owing to the public importance of the RPS program, there should be greater public access to RPS data than to many other types of data. The Commission expects all retail sellers to ensure the

> greatest public accessibility possible of their RPS compliance reports and other RPS information, consistent with the Commission's confidentiality rules.[167]

We recognize that the data to be collected here includes market-sensitive information. Within the context of the PCIA calculation, we expect this data will be protected under General Order 66-D.[168] We do not alter, here, confidentiality rules applicable to RPS contracts under D.12-06-038.

6.2.2. Annual True-up

TURN notes that "the Commission has long used true ups to reconcile discrepancies between forecast and actual values."[169] With respect to procurement costs, the Commission's ERRA 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 ERRA 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 … ."[170]

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 resources minus the revenues such resources earn in relevant markets [footnote: … this year-end reconciliation would also effectively true-up forecasted

---

[167] D. 12-06-038, at p. 78, footnote omitted.

[168] Adopted in D.17-09-023.

[169] TURN opening brief at 15.

[170] *Id.* at 16, citing Exhibit TURN-2 at 1.

> 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' ERRA Compliance applications."[171]

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.

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

[171] ORA opening brief at 12.

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."[172]

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.[173]

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."[174]

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 choice aggregator, through the expiration of all then existing electricity purchase contracts entered into by the electrical corporation'."[175]

Shell Energy supports a sunset and/or a fixed "cap" on a departing customer's PCIA cost responsibility.

---

[172] CalCCA opening brief at 141.

[173] Commercial Energy Opening brief at 36.

[174] CUE opening brief at 26.

[175] Joint Utilities opening brief at 80.

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 "[t]he 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."[176] 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 1.5 cents/kWh. If annual increases in the PCIA rate remain below that level, no cap would be applied.[177]

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."[178] AReM/DACC recommends that the Commission adopt a PCIA rate collar

---

[176] TURN opening brief at 33.

[177] *Id.* at 34.

[178] AReM/DACC opening brief at 38.

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.[179] 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."[180]

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 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."[181] 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

---

[179] AReM/DACC reply brief at 15-16.

[180] *Id.* at 16.

[181] Brightline opening brief at 11-12.

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.[182]

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."[183] 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 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. 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

---

[182] *Id.* at 12.

[183] CLECA opening brief at 6.

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."[184] 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."[185]

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."[186]

Parties offered further commentary on a cap and collar in comments,[187] and we conclude that a cap should be adopted in this decision, with some modifications in response to comments.

We find that the potential for volatility supports adoption of a PCIA cap in this decision. Such a cap should reduce extreme PCIA price spikes, and bill impacts, but not enable a continual state of significant undercollection. This proceeding corrects an outdated and flawed methodology for forecast year 2019, and the risk of substantial and immediate undercollections using a cap structure

---

[184] CUE reply brief at 22.

[185] CUE opening brief at 26.

[186] Joint Utilities opening brief at 70-71.

[187] *See* section 11, *infra*.

based on the prior methodology justifies waiting until forecast year 2020 to initiate the cap.

We affirm that a cap protects against volatility in the PCIA. The scenarios described by the Joint Utilities and Commercial Energy illustrate the potential for PCIA volatility: significant annual swings in energy prices leading to significant annual swings in the PCIA rate.[188] The CCAs indicated in comments that such swings make their resource planning extremely challenging, and the dismissal of those concerns by the Joint Utilities or Commercial Energy is unpersuasive.

Each utility shall establish an interest-bearing balancing account that shall be used if 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.

Starting with the ERRA forecast for 2020, the cap shall limit the PCIA's upward movement to 0.5 cents/kWh from the prior year's PCIA. We will monitor PCIA collections and balancing accounts closely and will provide oversight through a "trigger" mechanism as recommended by Brightline and ORA. The basis for our adopted trigger mechanism is the ERRA trigger mechanism established in D.02-10-062, modified as follows:

1. The PCIA trigger threshold is 10% of the forecast PCIA revenues.
2. If PG&E, SDG&E or SCE reach 7%, and forecast that the balance will reach 10%, they shall, within 60 days, file expedited

[188] Joint Utilities reply comments on the PD and APD at 8. ("Third, the PCIA mechanism has a self-stabilizing effect, because it is inversely correlated with market prices. As such, to the extent departing load customers pay a higher PCIA rate in a given year, they will pay less for the generation procured in the market to serve them that same year…)"

applications for approval in 60 days from the filing date when the balance reaches 7%.

3. The application shall include a projected account balance as of 60 days or more from the date of filing depending on when the balance will reach the 10% threshold.
4. The application shall propose a revised PCIA rate that will bring the projected account balance below 7% and maintain the balance below that level until January 1 of the following year, when the PCIA rate adopted in that utility's ERRA forecast proceeding will take effect.
5. The IOUs are authorized to notify the Commission through advice letter filing, instead of expedited application, when the PCIA balance exceeds its trigger point and the IOU does not seek a change in rates, if the IOU reasonably believes the balance will self-correct below the trigger point within 120 days of filing. The advice letter filing shall include necessary documentation to support the IOU's conclusion that the PCIA balance will self-correct below the trigger point within 120 days and that a rate change is not needed.

We base this trigger mechanism and process on the ERRA trigger process because it is a system that has been in place for some time and proven to be able to accomplish the same goals sought by the trigger implemented here.

We further affirm our conclusion that repayment of undercollections with interest is consistent with our statutory obligation to protect against cost shifts. Commenters arguing that the cap violates indifference do not demonstrate that interest paid on an undercollection balance fails to protect indifference. [189]

---

[189] Most parties agree. *See* POC opening comments at 14, ("because any undercollections will be repaid by departing load with interest, a cap achieves these goals without compromising customer indifference"). *See also* TURN opening brief at 34-35, ("The mere fact that undercollections are carried for more than a single year should not be the basis for determining that bundled customers are not held indifferent. Adopting an interest rate that fully

Footnote continued on next page

We revise the cap mechanism to remove the floor. We agree with comments by Brightline and TURN that the PCIA should be able to go negative and should credit departing customers when IOU portfolio value exceeds costs.

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."[190] For these reasons, AReM/DACC recommends that DA customers be permitted to pre-pay their PCIA obligations, conditioned upon the following specific terms:

- Prepayment would be based on a mutually acceptable forecast of that customer's future PCIA obligation;
- Prepayment could be either (a) one-time; or (b) a series of levelized payments over 2-5 years;
- Prepayment 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

---

compensates bundled customers for the risk and time value of money would ameliorate any concerns that mechanism results in a subsidy"). We acknowledge that TURN advocates a higher interest rate than we adopt in this decision to protect indifference.

[190] AReM/DACC opening brief at 36-37.

- Once paid, the customer could switch among competitive retail sellers without incurring any new PCIA obligation.

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,[191] and (2) commercial customers in other states have prepaid bundled service obligations when departing utility service.[192] 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.[193]

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."[194]

---

[191] 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."

[192] *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).

[193] CLECA opening brief at 18-19.

[194] Commercial Energy opening brief at 36.

UC cites the prepayment option as the type of measured,[195] opt-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."[196]

TURN strongly disagrees with permitting one-time prepayment "given the significant uncertainty associated with any forecast of long-term above-market costs."[197] 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.[198]

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:

---

[195] UC opening brief at 5.

[196] *Id.* at 6.

[197] TURN reply brief at 35, citing Exhibit TURN-2 at 23.

[198] *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).[199]

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. Furthermore, AReM/DACC effectively rebutted the Joint Utilities' expressed concerns about forecast-related market risk, volumetric risk, and regulatory risk.[200] 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.[201] The parties that best know the concerns and 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

---

[199] Joint Utilities opening brief at 87, citing Exhibit IOU-3 at 7-16 through7–17.

[200] AReM/DACC opening brief at 34-35.

[201] *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.

determine the best course of action based on the risk and economic preferences of that customer" (UC). Therefore, DA customers and CCAs, on behalf of their customers, will be permitted to pre-pay their PCIA obligations after resolution of additional issues surrounding the prepayment process in phase two.

As another means of mitigating any risks that may emerge as this provision is implemented, in the future we will require that any prepayment arrangements be submitted to the Commission via application, so that we may review the arrangements on a case-by-case basis.

6.2.5. Review of Other Proposals

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.

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.

The Joint Utilities request a "clarification or interpretation" of Portfolio Content Category 1 RECs as contained in 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 "[i]t 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."[202] 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.[203]

The Joint Utilities' proposal and request for Commission clarification are opposed by CalCCA, CUE, POC, UC, SEA and, most thoroughly, TURN.[204]

---

[202] ORA reply brief at 2-3.

[203] Brightline reply brief at 6.

[204] *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, SEA reply brief at 2-6 and TURN opening brief at 17-25 and reply brief at 24-29.

TURN asserts that the Joint Utilities' proposal fails because the LSE receiving the allocation does not actually receive any energy to serve its customers—that energy is retained by the IOU. TURN argues that, "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."[205]

TURN also raises 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.[206]

TURN also counters 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:

> 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

---

[205] TURN reply brief at 26, citing D.11-12-052 at 55.

[206] *Id.* at 27-28.

> 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.[207]

In addition to these policy concerns, as indicated above, SEA cites evidence that these proposals would result in substantially different departing load charges in different IOU territories. AReM/DACC believes that a modified PCIA would be significantly more predictable, understandable and transparent than new proposals such as the Joint IOUs' GAM/PMM proposal.

Beyond these specific objections to the Joint Utilities' GAM proposal with respect to categorization of PCC 1 RECs, a number of parties contend that the GAM/PMM is contrary to law because it "invades the procurement function reserved for CCA programs," a position opposed by the Joint Utilities.[208]

We decline to resolve the parties' conflicting views of the legal issues here because we reject GAM/PMM on policy grounds and thus render moot the

---

[207] *Id.* at 28-29.

[208] SEA reply brief at 1.

questions of statutory interpretation. GAM/PMM and PAM are both offered to resolve twin issues before us: 1) allocation of stranded costs among bundled and departing load, and 2) excess resources in the Joint Utilities' portfolios to serve a declining customer-base. This Commission will not pursue a policy scheme of mandatory portfolio allocation to CCAs and EPSs to resolve the problem of excess resources in the Joint Utilities' portfolios. We decline to adopt the Joint Utilities' GAM or PMM proposals for the policy reasons indicated above.
In phase two of this proceeding, we will explore voluntary, market-based solutions.

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 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 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, addressing optimization of IOU portfolio management, remaining alternatives to the PCIA framework, and forecasting of the PCIA.

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 to establish a 'working group' process to enable parties to further develop proposals regarding portfolio optimization and cost reduction for future consideration by the Commission.

7.1. General observations

AReM/DACC 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 if this phase 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."[209]

[209] AReM/DACC opening brief at 30.

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.

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 for possible securitization.

CSD 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."[210] CSD 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)

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

[210] CSD opening brief at 10-11.

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.[211]

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 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."[212]

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

---

[211] 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.

[212] ORA opening brief at 15, citing Exhibit ORA-1 at 9.

Commission, including that the PCIA only include legitimately unavoidable costs."[213]

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." Yet the Joint Utilities fail to show that the PRG and IE are accomplishing these objectives, and the record suggests they are not.[214]

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 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 to address the implementation details of the adopted measure(s), *e.g.*, an auction process, an

---

[213] POC opening brief at 27.

[214] POC opening brief at 28.

IOU procurement contract renegotiation process, and/or a procedure for securitizing IOU UOG assets.

SEA 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.[215]

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

[215] SEA opening brief at 11.

> with the allocation, sale and auction proposals that may be adopted in this proceeding.[216]

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.
- 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

[216] TURN opening brief at 16.

elimination of related PCIA charges.[217] 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.

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.[218]

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

---

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

[218] CalCCA opening brief at 97 and 142-144, respectively.

should question the added value of and necessity for an additional forum for assessing forecast demand and departing load.[219]

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.[220]

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 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."[221] 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;

[219] IEP opening brief at 4.

[220] Commercial Energy opening brief at 37.

[221] Joint Utilities opening brief at 80-81.

- Public data should be used to the greatest extent possible; and
- If confidential data are required, such data should be aggregated.[222]

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:

> 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.*

[222] *Id.* at 81.

- '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 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.[223]

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.

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

[223] AReM/DACC opening brief at 32-33.

high-priced RPS contracts.[224] 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 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

[224] 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.

savings. TURN recommends that the Commission endorse the concept and urge Legislative action in the current session and offers its assistance in that task.[225]

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 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

---

[225] 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.

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.[226]

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.[227]

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 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.

For these reasons, we find that a second phase should be opened in this proceeding. The second phase's purpose is to develop structures, processes, and rules governing portfolio optimization going forward. Portfolio optimization proposals should include voluntary auction frameworks. Although we decline to endorse any one voluntary auction proposal at this time, we remind parties that any proposals should be consistent with the guiding principles in this

---

[226] ORA opening brief at 14-15.

[227] TURN opening brief at 30-31.

decision. We anticipate the use of a working group process to develop these optimization proposals further. Some of the proposals offered by parties thus far in this proceeding would, if adopted, require coordination with other Commission proceedings, including the Integrated Resource Planning (IRP), Resource Adequacy (RA), and Renewable Portfolio Standard (RPS) proceedings. The second focus of phase two will be to minimize further accumulation of uneconomic costs. The Commission will consider further guidance and standards for more active management of the utilities' portfolios in response to departing load in the future, and improvements in forecasting of departing load by all LSEs. Phase two will also consider shareholder responsibility for future portfolio mismanagement, if any, so that neither bundled nor departing customers bear full cost responsibility if utilities do not meet established portfolio management standards. Utilities are of course required to manage their portfolios prudently. Imprudent management would justify disallowing recovery of portfolio costs, and could be considered in ERRA or General Rate Case (GRC) proceedings.

We note that there are already several regulatory venues that evaluate utility prudence in portfolio management. Public Utilities Code section 454.5(a-c) requires each IOU to follow a procurement plan approved by the Commission. ERRA proceedings routinely consider prudent management, including Standard of Conduct 4, which states "utilities shall prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner."[228] We further evaluate utility procurement through quarterly advice letters filed with

[228] D.02-10-062 at 52.

the Energy Division, which review "the type of any product purchased or sold, together with the bidding or other transaction procedure followed, and the contract's terms and price."[229] And pursuant to Public Utilities Code sections 454.51 and 454.52, we analyze procurement proposals and "authorize procurement, where appropriate, to meet the targets and needs identified in the IRP process."[230]

On the topic of departing load forecasts, we recognize that uncertainty can be a factor in forecasting customer departures. Prospective (or potentially expanding) CCAs must evaluate the energy markets, anticipate possible "opt-out" scenarios, and must work through certain systems (like utility billing) that they do not control. And utilities must weigh risks of CCAs delaying service, as Desert Community Energy did in the summer of 2018. While these forecasts may not become perfect, we hope through phase two to improve upon existing forecast practices, where possible, even if a degree of uncertainty remains.

We must caution that no easy solutions have arisen for these issues during the course of this proceeding. There remains a significant degree of uncertainty regarding what further portfolio optimization and management tools will be possible and effective. Nonetheless, we support further inquiry into these issues and expect all parties to participate in phase two in earnest, and with good faith. Given the range of complexities, ttopics will not necessarily have the same timeline. Some topics, like improved forecasts for departing load and further guidance and standards for active portfolio management in response to departing load may be resolved on a relatively abbreviated timeline. Other

[229] D.02-10-062 at 47, 50, COL 7; *see also* D.03-06-067 at 8-10.

[230] D.18-02-018 at 2.

topics involve the creation or transformation of energy markets, and these topics will likely require extensive coordination with other proceedings and careful consideration of appropriate rules and structure for such potential solutions. We will use the 'working group' process referenced below to further refine workplans and deliverables.

We appreciate parties' interest in reducing overall portfolio costs through financing strategies such as securitization. However, we are cautious about the feasibility of this strategy given recently adopted legislation regarding the securitization of wildfire liability costs.[231] It is unclear how additional utility securitizations would interact, and what implications there would be for overall utility borrowing costs. Given those uncertainties, we direct parties to focus on the abovementioned issues first.

Although we will consider the above-mentioned issues in phase two, we acknowledge that any resulting structures and rules developed must be coordinated and integrated with the IRP, RA, and RPS proceedings. In phase two, we will hold a prehearing conference to initiate that process. Phase two will also use a working group-based process to develop a record-based true-up for RA and RECs, and to provide further detail surrounding the prepayment option.[232]

In order to ensure that Phase 2 proceeds efficiently and results in the submittal of timely, actionable proposals to the Commission, we establish a framework based on a "working group" approach—as explained below, this approach has been successful in the past and we find that it will address parties'

---

[231] SB 901.

[232] *See* section 9.1, *infra*.

concerns regarding the need for Phase 2 to proceed based on clear guidance from the Commission, from the outset.

In 1995, when the Commission adopted market restructuring policies in its "Preferred Policy Decision" it stated "While this decision provides necessary policy guidance in our transition to competitive markets , the task of working to craft the necessary details and the pursuit of these objectives will be complicated and draw on the talents and cooperation of all stakeholders." The Commission subsequently issued its "Roadmap Decision" (D.96-03-022), which directed the formation of a number of "working groups" to be made up of interested stakeholders, to assist with the resolution of many implementation concerns. The group formed to address "consumer choice" issues such as direct access and consumer safeguards was named the Direct Access Working Group (DAWG). The DAWG's final report presented a compendium of ideas from the DAWG members regarding various consumer choice issues, and how those issues could be addressed in order to achieve the goals expressed by the Commission in its Preferred Policy Decision.

The Commission addressed the DAWG's recommendations in D.97-05-040 and ordered the Energy Division to conduct additional workshops to refine implementation details prior to market start-up. The workshops quickly led to the formation of five new working groups, whose ultimate recommendations were addressed by the Commission in five decisions: D.97-10-031 (Customer Information Data Base), D.97-10-086 (Load Profiling), D.97-10-087 (Direct Access Implementation Plan/Tariffs), D.97-12-048 (Meter and Data Communications), and D.97-12-090 (Retail Settlements and Information Flow).

The approach described above was effective because, while the process was facilitated and loosely coordinated by the Energy Division with the backing

of the Commission's authority, it was left to the directly interested stakeholders to work together to develop and recommend functional solutions to the challenges before them: to develop the rules and business practices that would govern to the soon-to-open direct access market. Make no mistake: the working group process was challenging, with the early stages marked by utility reluctance to collaborate clashing with private sector over-expectations regarding the services the utilities could provide. Nevertheless, as the Commission reminded stakeholders of its own expectations for a successful process, and as experts on both sides began to directly engage with each other, participants found common ground and, as noted, the Commission was able to quickly issue five decisions addressing highly technical matters, all within 5-7 months of the initiation of the working group process.

We are confident that a similar process can serve as the organizing framework for Phase 2 of this proceeding, and produce similar successes—albeit on a somewhat less compressed schedule. Our goal is to act on as many Phase 2 proposals as possible before the end of 2019, to allow us to take the final steps toward resolving the issues in this proceeding before 2020 begins. To that end, based on parties' comments and reply comments on the PD, we find that working groups should be established to address:

1. Benchmark true-up
    a. RA
    b. RPS
2. Prepayment
3. Portfolio Optimization and Cost Reduction
4. Allocation and Auction

The Commission and parties should further refine in a future prehearing conference and scoping memo, the number of working groups and process for formation. We anticipate that organizational workshops will facilitate refinement of the working groups scope, and that all participants shall assist with the preparation of a workplan for each working group, including a specific list of deliverables, and the schedule for completing the working group's self-assigned tasks by the end of October, 2019.

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.[233] 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.[234]

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,

---

[233] Exhibit AD-1 at 34.

[234] *Ibid.*

issues such as identifying the necessary substantive changes and conducting customer outreach will need to be addressed.[235]

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).

---

[235] Exhibit IOU-3 at 7-15.

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

CLECA supports greater transparency, but agrees with the Joint Utilities that the Commission should consider such changes in connection with GRCs: the Commission should defer the billing issues to the GRCs and direct the utilities to propose more transparent billing formats in their next Phase 2 proceedings.[236]

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

[236] CLECA opening brief at 30.

departing load (CGDL).[237] We are unaware of any such proposal in this proceeding, and we affirm that we leave existing treatment of CGDL undisturbed in this decision.

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, Commercial Energy, 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

[237] Opening brief of the Energy Producers and Users Coalition at 1-3.

use the PCC 1 REC index value ("California Bundled REC (Bucket 1)")[238] proposed by AReM/DACC.[239] The RPS adder for each utility will be the sum of the Platts PCC 1 REC index value and its brown power index. Energy Division shall use Platts' most recently published California Bundled REC (Bucket 1) mid value as of November 1, 2018. Due to the administrative burden of collecting RPS contract data and the limited time remaining for a 2019 ERRA forecast, we find the use of AReM/DACC's proposal preferable for the 2019 forecast. This will be an interim reliance on the Platts index to facilitate timely implementation, and we share TURN's concerns about reliance on Platts' index for a final market value for PCC 1 resources.[240]

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.

---

[238] On S&P Global Platts' Megawatt Daily: https://www.spglobal.com/platts/en/products-services/electric-power/megawatt-daily. *See* https://www.platts.com/IM.Platts.Content/Downloads/PDFs/FactSheetRECAssmnt.pdf for further information on Platts renewable certificate assessments.

[239] AReM/DACC opening brief at 23.

[240] TURN reply brief at 7.

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."[241]

Several parties opposed the Joint Utilities' proposal. CLECA states that it understands the concern that these costs be allocated in a similar way to 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."[242] Commercial Energy opposes the

[241] Exhibit IOU-1 at 4-65.

[242] Exhibit CLECA-1 at 26.

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.[243]

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

[243] Exhibit IOU-CLECA-1 at 3, statement of fact number 8.

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 be parties in those proceedings. For all 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

The PD and the APD found that the Joint Utilities' ratemaking proposal in Exhibit IOU-1 provides general concepts that could be used to implement the annual true-up process. We contemplated directing 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.

In comments, the Joint Utilities stated that the PD's discussion of the PABA ratemaking proposal omitted the Joint Utilities' proposals regarding portfolio-vintaged sub-account billed revenues, incremental costs, and associated market revenues. The Joint Utilities stated their intention to address this issue in detail in their comments on the APD (we note that the PD and the APD contain identical language regarding the PABA).

Turning then to the Joint Utilities' comments on the APD, they recommend eliminating the tracking of costs by the three components, as directed by the PD and the APD.[244] The Joint Utilities explain that few contracts, and no UOG generation assets, distinguish costs by specific attributes (i.e., energy, renewable or RA). Instead, many contracts have a single "per unit" price and generation resource costs are "cumulative."[245]

On the other hand, the Joint Utilities state that market revenues are more easily tracked and segmented according to the brown power index, RPS Adder and RA Adder, given the structure of the market price benchmark and the PD and APD's proposed true-up to actual market values for these components.[246] The Joint Utilities thus recommend that the PABA include subaccounts by vintage, with cost and revenue tracking as outlined in the Joint Utilities' testimony, but modified to include recording of REC sales revenues, monthly REC value at the adopted MPB, and an annual true-up entry for RECs to align with actual sales-weighted values compiled for the year.[247] According to the Joint Utilities, a vintaged subaccount approach is necessary for several reasons:

- to maintain "indifference" between different vintages of departing load customers;
- to differentiate the treatment of REC market value in the cost recovery mechanism;

---

[244] Joint Utilities comments on the APD at 14.

[245] *Ibid.* The Joint Utilities do not explain their statement that "generation resource costs are cumulative."

[246] *Ibid.*

[247] *Ibid.*

- to ensure the proper allocation and tracking of billed revenues, as well as generation resource revenues and costs for the true-up mechanism.[248]

The Joint Utilities also propose that both the PD and the APD be revised to require each utility to file a Tier 2 implementation advice letter 60 days after the issuance of the Commission's final decision. The advice letter would include each utility's proposed PABA preliminary statement and modifications to the ERRA and other generation-related balancing accounts needed to implement the final decision's directives. The advice letter would also include (1) a proposal regarding the timing and regulatory proceeding where the annual true-up entries would be presented for review, (2) details regarding how the true-up formula would capture the REC and RA attributes used for bundled service customer compliance, and (3) sales-weighted REC and RA true-up for attributes in the Joint Utilities' respective portfolios that are in excess of those needed for bundled service customer compliance.[249]

We have revised the true-up to be consistent with the conceptual approach recommended by the Joint Utilities, albeit without provisions to true up the RA and REC components, which we determined should not be subject to true-up at this time. If the Joint Utilities' proposed balancing account structure would aid in collecting information necessary to eventually true up those components, we authorize each utility to establish the necessary structure.

RPS and RA true up should be included in the scope of Phase 2 of this proceeding. The true-up does not need to be fully resolved immediately, and we

---

[248] *Id.* at 15.

[249] *Ibid.*

anticipate that a working group process will facilitate the development of a record-based true-up process for RA and RPS, with the goal of developing a true-up process for RA and RPS by the end of 2019.

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 ERRA 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 PPAs 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 Alternate Proposed Decision

The alternate proposed decision of Commissioner Peterman 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 or before September 6, 2018 by AReM/DACC, SEA, PCE, CalCCA, MCE, CLECA, Commercial Energy (CE), Joint Utilities, 350 Bay Area, TURN, POC, and Public Advocates Office (Cal PA, formerly known as ORA). Reply comments were filed and served on September 13, 2018 by SEA, AReM/DACC, Joint Utilities, MCE, SCP, UCAN, San Jose Clean Energy (SJCE), PCE, TURN, Shell, Cal PA, CLECA, East Bay Community Energy (EBCE), POC, CalCCA, Brightline, CUE, CE, and Independent Energy Producers Association (IEPA). These comments have been considered, and changes in response to those comments are found in this revised alternate proposed decision. A subset of issues raised in party comments are further described below. As noted by CE, Rule 14.3 provides that "Comments shall focus on factual, legal, or technical errors in the proposed or alternate decision and in citing such errors shall make specific references to the record or applicable law. Comments which fail to do so will be accorded no weight."[250]

---

[250] Rules of Practice and Procedure; *see* CE reply comments at 9-10 (asserting that comments by CCA parties make claims about the financial and policy impact of the

Footnote continued on next page

Cap

Parties' comments on the cap ranged from strong support to strong opposition.

Several parties raised concerns with the use of a 25% collar commencing in 2020.

350 Bay Area asserted that a 25% collar is too large to provide cost certainty and advocated a 10% collar insead.[251]

The Joint Utilities argued against the institution of a collar at all, claiming that it is arbitrary and would shift costs.[252]

AReM/DACC asserted that the collar mechanism provides inadequate protection when needed and protection when unneeded.[253] AReM/DACC stated that the PD's collar structure, with a starting amount set at the maximum current PCIA would be superior.[254]

CUE supported a collar with an up or down fluctuation of 25% from the prior year's PCIA starting in 2020.[255]

SEA opposed a cap starting in 2020 and argues that a 25% year-over-year increase "fails to provide meaningful cost control because it could easily result in large increases over a relatively short period of time and would allow

---

PCIA without record evidence of the facts underlying the financial claims made in those comments).

[251] 350 Bay Area APD comments at 7.

[252] Joint Utilities APD comments at 5-10.

[253] AReM/DACC APD comments at 14 (illustrating a 25% collar with a 0.04 cents/kWh PCIA and with a 4 cents/kWh PCIA).

[254] AReM/DACC APD comments at 14-15.

[255] CUE reply comments at 9.

discrepancies among the PCIA charges imposed by the different IOUs to persist."[256]

CE supported the 25% rate collar.[257]

Brightline proposed eliminating any PCIA floor and argued that any cap should have a review mechanism, like a trigger in case undercollections exceed a certain amount.[258]

CalCCA requested adoption of a fixed 0.3 cents/kWh collar on the PCIA.[259]

TURN proposed a 0.5 cents/kWh limit on PCIA increases, with an undercollection interest rate established at the rate of the Weighted Average Cost of Capital and a net credit to departing load if the IOU portfolios are below market.[260]

PCE opposes a 25% rate collar starting in 2020, preferring a 2019 cap at 2.2 cents/kWh and a permanent floor of 0.0 cents/kWh.[261]

POC supports the PD's proposal to set a cap on the PCIA equal to 2.2 cents per kWh, although in reply comments POC states that it is also amenable to AReM/DACC's revised proposal to set the initial PCIA cap at the maximum 2018 PCIA rates.[262] In either case, POC recommends that the PD be revised to

---

[256] SEA APD comments at 6.

[257] CE APD comments at 1.

[258] Brightline reply comments at 5-6.

[259] CalCCA reply comments at 10.

[260] TURN APD comments at 5-6; TURN reply comments at 10.

[261] *See* PCE APD comments at 13.

[262] POC opening comments on the PD and APD at 13; POC reply comments at 1, footnote 3.

treat the adopted level as a "hard" or "absolute" cap, with no built-in escalation provisions. If the PCIA were to exceed the hard cap, any undercollections would roll over to be collected with interest from departing load in future years. POC acknowledges that "scalars" do provide some protection against year-to-year rate volatility, but contends that they would introduce unnecessary uncertainty into PCIA charges,

> impeding CCAs' ability to forecast and plan for PCIA obligations. Stability and predictability in departing load charges is particularly important for new and emerging CCAs, which invest significant resources in designing rates to incorporate expected PCIA charges.[263]

POC also notes that "unlike the proposed scalars [in the PD and the APD], an absolute cap has also already been vetted in Commission practice through the CRS, where it proved to be a durable mechanism to stabilize rates."[264] Finally, POC notes that "because any undercollections will be repaid by departing load with interest, a cap achieves these goals without compromising customer indifference."[265]

We are persuaded that a change to the collar mechanism is appropriate. As described in section 6.2.3.2 above, a cap on upwards PCIA changes shall be instituted for forecast year 2020, limiting PCIA increases to 0.5 cents/kWh over the prior year. This proceeding corrects an outdated and flawed methodology for forecast year 2019, and the risk of substantial and immediate undercollections

---

[263] POC opening comments on the PD and APD at 13-14, (*citing* the Opening Brief of LACCE, CVAG, and WRCOG at 7-8, Opening Brief of Solana Energy Alliance at 11).

[264] *Ibid.*, citing Exhibit AD-1 at 29 "(testifying that the CRS cap did not change)" and D.03-07-030 at 106

"(retaining the 2.7 cents/kWh cap level for the period on an after July 1, 2003)."

[265] *Ibid.*

using a cap structure based on the prior methodology justifies waiting until forecast year 2020 to initiate the cap. We also adopt a trigger based on the ERRA trigger mechanism established in D.02-10-062.

Legacy UOG

CalCCA and several other parties[266] reiterate arguments against the inclusion of legacy UOG for CCA PCIA cost recovery. Several parties oppose that position, supporting the continued inclusion of legacy UOG in the PCIA, including TURN, ORA, Commercial Energy, CLECA, and the Joint Utilities. CLECA offered additional bases and authority for including legacy UOG in the PCIA for CCAs, some of which has been added to section 5.1, above.[267]

In addition to the statutory interpretation arguments discussed in section 5.1 of this Decision, CalCCA argues that capital investment and operating costs are continuing for legacy UOG, are incurred after load departure, and represent a benefit to bundled customers. In support of this position, CalCCA cites its testimony about the value of utility plants and to the 2014-2016 PG&E General Rate Case (GRC) Decision.[268]

Marin Energy Authority (now MCE), and AReM/DACC were parties to the cited GRC. Neither of those parties offered comment in A.12-11-009 suggesting that continued plant investments are not attributable to departing load. CalCCA's testimony on this subject urges us to recognize additional value that CalCCA purports UOG to provide or to remove ongoing costs for certain

---

[266] *See*, *e.g.*, SEA APD comments at 2, 350 Bay Area APD comments at 6, UCAN APD comments at 2-4.

[267] *See* CLECA APD comments at 3-6.

[268] CalCCA APD comments at 14.

plants[269] from PCIA recovery. Indeed, CalCCA's testimony suggested that retaining legacy UOG in the PCIA could be reasonable if the Commission were to: 1) attribute a premium value to GHG-free resources . . ., 2) securitize UOG assets . . ., and 3) provide CCAs and other bidders with access to GHG-free resources."[270]

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

10-year limit on post-2002 UOG

Several parties oppose the termination of the 10-year limit on PCIA recovery of post-2002 UOG, including CalCCA, UCAN, and AReM/DACC.[271] Parties including TURN, Cal PA, CUE, Brightline, and the Joint Utilities support

---

[269] Diablo Canyon, Humboldt, Pebbly Beach, Helms, and Eastwood, *see* CalCCA Testimony at 2B-17-2B-18.

[270] CalCCA Testimony at 2B-20.

[271] *See*, *e.g.*, CalCCA APD comments at 14-15, UCAN APD comments at 4-5, AReM/DACC APD comments at 12-13.

terminating the 10-year limit on PCIA recovery.[272] While positions vary, the line of argument for keeping the 10-year limit is illustrated by the position of AReM/DACC, which stated, "ten years is more than sufficient time for a utility to adjust its portfolio to reflect changes in its load. . . . '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.'"[273] The parties opposing the termination of the 10-year limit have demonstrated no factual, legal, or technical error in their comments on the subject. Recovery from bundled customers mutes—if not outright eliminates—any purported incentive to manage portfolios more aggressively; thus we initiate a second phase in this proceeding aimed at portfolio optimization and cost reduction.

Phase II

Numerous parties requested further description of Phase II in their comments. The Joint Utilities suggested that Phase II should include proposals to improve forecasts of departing load, including making the Binding Notice of Intent mandatory for CCAs to commence service.[274] The Joint Utilities also argued that new rules for IOU market activities should transition to the Integrated Resource Plan (IRP) or a new rulemaking proceeding after development through a workshop process.[275] The Joint Utilities further suggest

---

[272] *See*, *e.g.*, Brightline reply comments at 3, CUE reply comments at 7-8, TURN APD comments at 4.

[273] AReM/DACC APD comments at 12 (*quoting* PD at 59).

[274] Joint Utilities APD comments at 22.

[275] Joint Utilities APD comments at 23.

that Phase II focus exclusively on going-forward solutions to portfolio optimization and not revisit previously approved procurement.[276]

350 Bay Area asserts that the parties to Phase 2 may need an independent mediator to avoid slowing progress.[277]

UCAN urges the Commission to consider locational cost shifts embedded in cost of service, rate design, and energy markets in Phase II.[278]

SCP argues that Phase II can only be successful if it is made clear that the Joint Utilities failed to follow Commission rules to minimize ratepayer costs and that the Joint Utilities' portfolio management is subject to reasonableness review.[279]

SJCE asserts Phase II should determine "whether and to what extent utility [PPAs] are above market."[280]

CE requests clear guidance and principles for Phase II, specifically asking for clarification that Phase II will implement a solution that includes a voluntary allocation and auction clearinghouse.[281]

We have added description of phase II in section 7.6, above.

True up

Several parties commented on the PCIA true-up. As explained below, in response to parties' comments, we have revised the PCIA true-up.

---

[276] Joint Utilities APD comments at 24-25.

[277] 350 Bay Area APD comments at 5.

[278] UCAN APD comments at 5-7.

[279] SCP reply comments at 7.

[280] SJCE reply comments at 4.

[281] CE APD comments at 4.

CalCCA, after reiterating some of its true-up concerns, suggested a limited true-up for "(1) total generation quantities and costs; (2) energy purchase and sales revenues; (3) reasonably forecast RA purchase and sales revenues; and (4) reasonably forecast RPS purchase and sales revenues. The forecast portfolio value, or benchmarked market value, would not be subject to true up."[282]

AReM/DACC argued for the elimination of a true-up, or in the alternative for a true-up of brown power costs only.[283] AReM/DACC faulted the true-up, contending that there is insufficient information in Exhibit IOU-1 to provide guidance to the IOUs regarding how to implement an annual true-up of all three of the PCIA elements (brown power, RPS Adder and RA Adder). AReM/DACC note that Exhibit IOU-1 only addresses the brown power element of the true-up. More importantly, AReM/DACC assert that "the flaw is that analogous 'actual' pricing for RPS values and RA do not exist."[284] AReM/DACC recommend omission of a true-up altogether. However, if the Commission does adopt a true-up, AReM/DACC recommend that it be modified so that only the brown power costs are trued up. Such a true-up would be based on "the difference between the forecast and actual market prices, sales volumes and PCIA revenue collections."[285] Finally, AReM/DACC recommend that any further discussion of an RPS or RA true up should be included in the scope of second phase of this proceeding.[286]

---

[282] CalCCA APD comments at 16.

[283] AReM/DACC APD comments at 11-12.

[284] AReM/DACC PD comments at 9.

[285] *Id.* at 10.

[286] *Ibid.*

CUE supported a true-up to reconcile forecasted and actual costs and recorded market transactions to provide for the value of IOU resources.[287] Brightline similarly supported a true-up based on market data.[288]

CalCCA faults the true-up for reasons similar to AReM/DACC: "truing up initial forecasts of proxy value with a later estimate of the proxy value does not increase accuracy and could magnify existing uncertainties or flaws in the underlying methodology."[289] CalCCA opposes updating the RA, RPS and (if adopted) GHG-free proxy prices used for the MPB:

> Unlike the other elements of CalCCA's proposed true-up, these proxies do not reflect actual transactions to buy or sell the portfolio attributes, actual bundled customer costs and tariff sales revenues, or verifiable market values for these portfolio attributes. Quite simply, a significant portion of the portfolio is not transacted in the market in auctions, bilateral contracts, or other mechanisms. The benchmarks for these attributes thus represent only estimates of the value bundled customers would otherwise pay for these resources in the market.[290]

For these reasons, CalCCA also recommends that any true-up be limited to brown power, and contends that its own proposal reaches essentially the same result as the AReM/DACC proposal. CalCCA supports a true-up of only the inputs to the PCIA calculation that are also a part of the standard ERRA true-up calculation:

1. quantities of generation, fuel, and purchased power; and

---

[287] CUE reply comments at 2-3.

[288] Brightline reply comments at 4.

[289] CalCCA reply comments at 7, emphasis added.

[290] *Id.* at 6-7.

2. costs of fuel, operations and maintenance expenses and purchased power.

In addition, CalCCA clarifies that in order to be used for the PCIA true-up, the ERRA standard practice must also be modified to address benchmark values; CalCCA supports a limited, after-the-fact update of the following:

i. the brown power component of the MPB, substituting recorded CAISO market-clearing energy and ancillary services prices for those set on a forecast basis using Platts forward prices for the purchase and sale of all non-UOG resources and actual revenues for UOG resources; and
ii. an update of the quantities of the resources represented in the MPB.

The Joint Utilities oppose the AReM/DACC and CalCCA proposals, asserting that all portfolio components and market outcomes must be trued up to actual results because "anything less results in prohibited cost shifts."[291] Specifically, the Joint Utilities contend that their long RPS positions should be trued-up for actual market results, including a zero value for RECs that they are unable to sell, because RPS-eligible contracts represent the majority of above-market costs in the Joint Utilities' portfolios; thus, correctly valuing the Joint Utilities' long RPS positions is "crucial" to maintaining bundled service customer indifference.[292] Regarding RA, the Joint Utilities state that the PD (and the APD) "correctly recognize that an excess product only has value to the extent which, and for the amount that, it can be sold. Ascribing any additional 'value' is contrary to economic principles and would result in cost-shifting to bundled service customers."[293]

---

[291] Joint Utilities reply comments at 3.

[292] *Id.* at 4.

[293] *Ibid.*

TURN suggests that CalCCA's proposal would "eviscerate" the purpose of a true-up; TURN also asserts that CalCCA's proposals are disconnected from the determination of bundled customer cost responsibility under the ERRA process.[294]

We have carefully reviewed the parties' criticisms of the PD and APD regarding the true-up, and we have revised this APD to reflect our conclusion that, at least initially, only brown power costs should be trued up. We agree with AReM/DACC and find that we do not have sufficient record evidence to explain in detail how RPS or RA should be trued up. The material provided by the Joint Utilities in comments and reply comments does not cite to our record. We also agree with AReM/DACC and CalCCA that merely truing up initial forecasts of a proxy value with a later estimate of the proxy value would not necessarily increase accuracy and could lead to unknown consequences. In this regard, the PCIA true-up differs from the ERRA true-up because the ERRA true-up is self-contained in a manner that excludes cost-shifting as a concern: bundled ratepayers pay the forecast ERRA rate for a year, the actual costs and revenues are tracked, and the same ratepayers pay a new ERRA rate the next year that is adjusted for any forecast-related variances in the prior year. The PCIA, at this time, cannot be relied upon to have the same result if RPS and RA are included in the true-up: the recorded "actuals" do not reflect the untransacted capacity used for bundled customer compliance or the untransacted RECs either used for compliance or banked for future use.

[294] TURN reply comments at 5.

For these reasons, we conclude that we should adopt, at least for now, only the limited true-up proposed by AReM/DACC. However, even truing up only the Brown Power component of the PCIA is, methodologically, a significant advance compared to our current practices. If not for the compressed schedule of this proceeding, we are confident that further advances are possible.

For that reason, we also agree with AReM/DACC that further discussion of an RPS or RA true up should be included in the scope of Phase 2 of this proceeding with the goal of developing a true up process for RA and RPS by the end of 2019. While a true-up of all attributes of utility portfolios would provide the most accurate PCIA, there are complexities with a true-up of untransacted capacity and RECs that need further record development to resolve. The true-up does not need to be resolved immediately, and we anticipate that a working group process, to start no later than sixty (60) days after the adoption of this decision, will facilitate the development of a record-based true-up process for RA and RPS. We encourage those parties who believe that RPS and RA can be accurately trued up to work with other parties in Phase 2 and present us with evidence that demonstrates this is the case.

Prepayment

Several parties commented on the prepayment option. Cal PA, TURN, and Brightline urged the Commission to eliminate the prepayment option.[295] In essence, comments opposing the prepayment option argued that such a mechanism would not protect indifference because forecasts will deviate from the future realities of the IOU portfolios and the energy markets.

---

[295] Brightline reply comments at 4-5; Cal PA APD comments at 2-3; TURN reply comments at 6-7.

Other parties offered supporting comments for the prepayment option, including the Joint Utilities, SCP, and AReM/DACC.[296]

As discussed in section 6.2.4, above, prepayment is intended to provide departing load an option to manage its portion of the above-market costs in the utility portfolio in a manner that aligns with the entity's procurement needs and goals. The application process provides sufficient fact-finding and administrative process to protect indifference for affected interests who are not party to any particular prepayment negotiation.

If further guidance is needed on the prepayment process, we will consider addressing it in phase two.

The Joint Utilities modified the position taken in their briefs and described above, now stating that while they continue to have concerns regarding the risk to bundled service customers inherent in the prepayment of the PCIA, they "acknowledge that the prepayment option provides simplicity and predictability to departing load customers, and may be appropriate in certain instances."[297] Accordingly, the Joint Utilities support the guidelines proposed for prepayment with limited clarifications.

AReM/DACC continue to support a prepayment option and assert that the proceeding record provides no support for the contentions of prepayment opponents that prepayment does not ensure indifference. AReM/DACC recommend use of a Tier 3 advice letter process rather than one-time

---

[296] AReM/DACC reply comments at 5; Joint Utilities reply comments at 10; SCP reply comments at 5-6;

[297] Joint Utilities comments on the APD at 17.

applications, because this would still permit interested parties to file comments either in opposition or support.

CalCCA supports prepayment, reiterating that a primary challenge associated with the PCIA is the volatility combined with lack of transparency and, for that reason, there is significant value to be gained by a known, one-time prepayment of charges. However, CalCCA also asserts that prepayment is unlikely to succeed as written. Each of the Joint Utilities currently has a "New Municipal Departing Load" tariff that includes the option to negotiate bilateral agreements to resolve PCIA and other departing load obligations. According to CalCCA, CCAs have not had any success in working with IOUs to make use of the existing provisions in IOU tariffs to negotiate prepayment. Therefore, CalCCA recommends revision as follows:

- Require utility forecasts, on an ongoing basis, of the each vintage's departing load obligations; and
- Require the utilities to offer a prepayment calculated using the forecast of obligations, as specified by AReM/DACC.[298]

SCP supports the proposed prepayment for a number of reasons:

- The proposal "properly rejects the argument that any prepayment without a true-up would somehow violate principles of indifference;"[299]
- The proposal recognizes that any true-up or refund following a prepayment would essentially prevent financing because it would destroy the very certainty the prepayment is intended to provide.[300]
- The proposal acknowledges the importance of flexible payment terms (e.g. one-time or levelized over multiple years).[301]

---

[298] *See* CalCCA PD comments at 15-16.

[299] SCP PD comments at 10.

[300] *See* SCP PD comments at 10-11.

Still, SCP agrees with CalCCA that the prepayment structure does not establish a framework that is likely to result in prepayments.[302] SCP references examples of successful prepayments in other jurisdictions, and emphasizes that success requires a context in which both parties willingly worked together to develop terms for prepayment.[303] SCP thus recommends three revisions regarding prepayment:

(1) Require that IOUs forecast departing load obligations;
(2) Utilize Commission-approved values and standards for measuring indifference; and
(3) Move beyond mere "good faith obligations" to order IOUs to offer prepayment on terms that maintain the Commission-defined indifference, such that a failure to do so by an IOU is independently enforceable.[304]

SCP suggests that a Tier 3 Advice Letter is an appropriate procedural vehicle for the Commission to review and approve pre-payments, although use of Tier 2 Advice Letters could be considered if the Commission more fully developed the terms of acceptable pre-payment in phase two.[305] Finally, SCP recommends that in order to encourage interest in pre-payment by CCAs, partial pre-payments should be allowed.[306]

---

[301] SCP PD comments at 8.

[302] SCP PD comments at 9.

[303] SCP PD comments at 9-10.

[304] SCP reply comments at 4.

[305] SCP reply comments at 4-5.

[306] SCP reply comments at 5.

Turning to parties that oppose adoption of a prepayment option, Brightline recommends that the Commission eliminate this option, asserting that prepayment would deliver certainty to departing load customers at the expense of equity as well as the Overall Goal of this proceeding: customer indifference.[307]

Cal PA also opposes prepayment, contending that allowing Direct Access and CCA customers to pre-pay their PCIA obligation carries the risk of inaccurately accounting for their full cost responsibilities.[308]

Finally, as noted above, the Joint Utilities have modified their position since briefs were filed and served and now support the guidelines proposed in the APD (which mirror the PD), with limited clarifications regarding issues that should be addressed in phase two of this proceeding. Primarily, like CalCCA and SCP, the Joint Utilities note that the Commission must provide guidance regarding criteria to evaluate the reasonableness of a proposed prepayment amount.

As described below, we have revised the prepayments section to address issues raised in comments. In doing so, we reiterate that one of the guiding principles in this proceeding is that any PCIA methodology adopted by the Commission "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 affirm that principle by preserving the determination that prepayment arrangements should be allowed. Just as importantly, however, we also acknowledge concerns that any prepayment proposals must leave us confident that the obligation to be prepaid has been

[307] Brightline reply comments at 4-5.

[308] Cal PA APD comments at 2-3.

forecast and calculated as accurately as possible, given inherent market uncertainties. We agree with CalCCA, SCP and the Joint Utilities that more direction and detail is necessary before we can begin to consider prepayment proposals, but we find that parties should work together to recommend the proper criteria. We have revised so that applications for prepayment will not be accepted until additional direction and detail are resolved in phase two. Among the topics interested parties should discuss in the context of prepayment will be whether to require the IOUs to develop and maintain, on an ongoing basis, a forecast of departing load obligations for each vintage of departed load. Within that discussion, parties should resolve issues surrounding any market-sensitive forecasts of future prices in energy markets. Therefore, we modify the PD as follows:

1. The references to "good faith negotiations" have been removed from this final decision.
2. We will direct the Energy Division to facilitate the formation of a "Prepayment Working Group" to be comprised of interested parties, and tasked with developing and submitting a final prepayment mechanism to the Commission for its consideration, approval and implementation.
3. The working group shall develop and provide to the Commission a consensus recommendation regarding the criteria that should be used to evaluate the reasonableness of any proposed prepayment amounts.
4. After phase two provides further direction and detail for prepayment proposals, we will accept Applications for the approval of negotiated prepayment agreements.

Finally, as is true of many aspects of the next phase of this proceeding, the success of the working group we describe here will depend on the active and collaborative participation of the Joint Utilities. In their reply comments, the Joint Utilities identified two additional issues they suggest be considered in

phase two: confidentiality rules governing procurement data used to determine the prepayment amount, and "a threshold showing by CCAs and DA customers on their financial ability to secure prepayment funds, in order to ensure that negotiations are entered into in good faith."[309] We state here that the second item on this list should not be a condition precedent to developing a prepayment framework, and that we expect the Joint Utilities and all other interested parties to move with all deliberate speed as part of the working group that brings us the proposals identified above.*PCIA Benchmarks*

A number of parties offered comments on the PCIA benchmarks.

In connection with concerns about requiring ESPs to submit contract information to the Commission, Commercial Energy urged the use of *Platts* RPS indices on a permanent basis for an RPS adder, and to rely solely on IOU data for an RA benchmark.[310]

CCAs argued for a GHG-free benchmark and argued that the RA Report undervalues capacity.[311] These parties assert that there is a value in GHG-free energy retained by bundled customers that is not captured by the proposed PCIA benchmarks. Regarding capacity, these parties assert that there are long-term reliability and price hedging values in the IOU portfolios, which the RA Report does not capture. CalCCA's view is that a capacity benchmark should consist of:

> *System RA.* The Energy Division RA Report's "85% of MW at or below" price for

---

[309] Joint Utilities reply comments at 10.

[310] Commercial Energy reply comments at 8.

[311] *See*, *e.g.*, CalCCA reply comments at 2-6, 8-10; EBCE reply comments at 7-10; PCE APD comments at 3; SEA APD comments at 10; SJCE reply comments at 3.

> System RA would be selected and used in the weighted average System RA price calculation in proportion to the percentage of compliance products represented by the reported transactions. For example, if 25% of all system RA compliance requirements are met through these short-term transactions, the RA Report "85% of MW at or below" System RA price would be weighted 25% in the system RA capacity benchmark, while the remaining 75% of the System RA capacity would be valued at the short-run "going forward" operating costs of a combustion turbine, as valued by the CEC ("going forward" cost); this value is comparable to (albeit, still lower than) the avoidable cost the bundled customers incur for the provision of RA from UOG fossil resources.
>
> *Local RA.* The Energy Division RA Report's "85% of MW at or below" price for Local RA would be selected and used in the weighted-average Local RA price calculation in proportion to the percentage of compliance products represented by the reported transactions. If, for example, 25% of all system RA compliance requirements are met through these short-term transactions, the RA Report "85% of MW at or below" Local RA price would be weighted 25% in the Local RA capacity benchmark, while the remaining 75% of the Local RA capacity would be valued at the weighted average CAISO CPM price.
>
> *Flexible RA.* Because there are no clear, liquid benchmarks or referents for flexible capacity, all flexible capacity should be valued at the existing "going forward" RA benchmark.[312]

TURN and the Joint Utilities, on the other hand, support the proposed benchmarks.[313]

Other parties had alternative views. AReM/DACC proposed using the *Platts* index on a permanent basis to value RPS resources, and using the existing benchmark for capacity unless new capacity resources are needed within three years, in which case a combustion turbine's cost of new entry should be used (drawn from the CEC's Cost of New Generation Report).

POC opposes the use of a zero or *de minimis* value for unsold RA, arguing that such products have values for hedging to meet current or future compliance obligations.

CLECA opposes the use of a GHG-free adder.[314]

---

[312] CalCCA PD comments at 13-14.

[313] Joint Utilities reply comments at 5-8; TURN reply comments at 1-4.

Shell proposes "the use of IOU transaction data, commercial indices, and a robust electronic bulletin board [] to develop an estimate of market prices for brown power, resource adequacy [] capacity, and renewables portfolio standard [] energy."[315]

We first address the GHG-free adder proposed by CalCCA. CalCCA did not demonstrate the need for a separate GHG-free adder (which would apply to hydroelectric and nuclear power) in this proceeding. CalCCA's position in testimony was that we should administratively apply the RPS adder to all GHG-free generation.[316] This approach is untethered to any reliable, observable market premium. While CalCCA's advocacy on alternative amounts for such an adder has shifted, there remains a paucity of evidence in this proceeding supporting an observable, reliable market premium for this category of energy resources.

A market premium attributable to GHG-free resources, to the extent it exists, will be captured in our true-up—a true-up which CalCCA would only support if it did not true-up for any premium value achieved by GHG-free resources, among other conditions.[317] The Joint utilities noted that

> [d]ispatched GHG-free resources command the same market-clearing prices as all other resources, but do not have a corresponding GHG compliance cost. Accordingly, the delta between their costs and awarded revenues is larger than a fossil resource. . . . This value is already pro-ratably shared with

---

[314] CLECA reply comments at 5-6.

[315] Shell reply comments at 2.

[316] Ex. CalCCA-1 at 2B-11.

[317] CalCCA reply comments at 6.

> departing load customers, as it is captured in the PCIA's 'brown' MPB when trued-up for actual market revenues.[318]

Moreover, applying a GHG-free adder amid scarce data on GHG-free resource transaction premiums is unwarranted. CalCCA's proposed $6.14/MWh (itself a substantial reduction from the $24.16/MWh for PG&E and $25.11/MWh for SCE that CalCCA proposed in testimony)[319] is not tied to any market transactions.[320] TURN offered the limited transaction price data in the record—a $2/MWh premium estimate reported by Sonoma Clean Power in February 2017.[321] The Joint Utilities noted that, for planning purposes, the City of San Diego assumed $3.50/MWh was the GHG-free adder used by the City of San Diego in July 2017 in their the Short-Term Cost of Service Model included in their CCA Feasibility Study.[322] Neither of these GHG values represent a reliable market value on which to base an additional GHG-free benchmark that would apply to the hydroelectric and nuclear resources in the IOU portfolios.

---

[318] Joint Utilities reply comments at 5. *See also* TURN reply brief at 18.

[319] *See* CalCCA opening brief at 66, *citing* Exhibit CalCCA-1 at 2B-11:13-19.

[320] TURN reply brief at 18.

[321] TURN reply comments at 1, *citing* Exhibit IOU-2 (IOU rebuttal testimony) at 2-25 (which points to Sonoma Clean Power's Community Advisory Committee Minutes: https://sonomacleanpower.org/uploads/documents/Final-Signed-Minutes-2017.02.14.pdf).

The linked minutes state (at page 2):

> CM Williamson asked for a general idea of the current cost of energy procured. Director Emerson stated that carbon free was less than *$2 per MWh*. CEO Syphers explained that this is the premium above the cost of general energy. Director Emerson stated that category 2 was less than $6 and category 1 was less than $19. (emphasis added)

[322] IOU Rebuttal Testimony, p. 2-25, lines 13-15.

If market changes demonstrate a consistent heightened value for GHG-free resources in the coming years, then it might be appropriate to re-evaluate the need for a GHG-free adder to reduce the gap between a forecast PCIA and a trued-up PCIA.

We turn next to the RPS adder. While several parties have urged the use of the *Platts* RPS index on a permanent basis, we decline to do so. The *Platts* PCC 1 REC index is new and it is proprietary. The index lacks a track record sufficient to justify relying on it to forecast the market value of RECs in California.

Many parties have acknowledged the challenges inherent in determining a benchmark for capacity. We are not persuaded that any of the alternatives proposed represent a better capacity benchmark than the RA Report.

Reporting Requirements

Commercial Energy, Shell, and CLECA argued that new reporting requirements are beyond the Commission's jurisdiction, lack legal basis, and risk the exposure of highly confidential information. We have modified section 6.2.1.1 of this Decision to address their arguments.

Non-Vintaged Departing Load Charge

In comments, citing earlier testimony in this proceeding, the Joint IOUs advocate for the institution of a non-vintaged departing load charge for procurement mandates like Renewable Market Adjusting Tariff, Bioenergy Market Adjusting Tariff, Renewable Auction Mechanism, and the Public Utility Regulatory Policies Act program.[323] Other parties oppose this charge.[324]

---

[323] Joint Utilities APD comments at 15.

[324] *See*, *e.g.*, CLECA reply comments at 2-4; POC reply comments at 10.

We are not persuaded to render these broad swathes of procurement non-vintaged here. Cost recovery for these and potential future procurement programs is best addressed in proceedings approving such procurement.

Pre-2009 Direct Access

AReM/DACC urges explicit clarification that the pre-2009 customers' obligations will be addressed in A.16-04-018, and not in this proceeding.[325] The record in this docket is inadequate to disrupt the status quo for pre-2009 Direct Access customers' treatment under the PCIA, and we decline to alter it without prejudice to any decision resolving the issue in A.16-04-018 or other Commission proceedings.

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

[325] AReM/DACC APD comments at 5.

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. Allocating RECs to an LSE without providing the associated energy is not identical to a forward sale of bundled renewable energy.

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

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

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

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

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

14. 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.

15. A true-up mechanism will increase the accuracy of the PCIA cost allocation between bundled and departing load customers.

16. The record in this proceeding is only sufficient to develop a true up to account for the costs and revenues associated with the Brown Power Index at this time.

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

18. A PCIA cap will limit the change of the PCIA from one year to the next. A cap that limits the change of the PCIA from one year to the next promotes certainty and stability for all customers within a reasonable planning horizon.

19. A "trigger" process for the PCIA rate similar to the existing ERRA trigger mechanism provides flexibility to avoid excessive undercollections.

20. The PCIA rate can produce a credit to departing load if a utility portfolio provides positive net market value as demonstrated through actual recorded market transactions and realized revenues.

21. 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.

22. 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.

23. 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.

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

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

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

27. 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. 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.

7. The RA Adder and RPS Adder methodologies proposed by CalCCA should not be adopted.

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

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

10. The Legislature intended, in AB 117, "to prevent any shifting of recoverable costs between customers."

11. In SB 350, the Legislature directed that "[b]undled retail customers of an electrical corporation shall not experience any cost increase as a result of the implementation of a community choice aggregator program. The commission shall also ensure that departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load."

12. Including the costs of pre-2002 Legacy UOG within the PCIA is consistent with AB 117 and SB 350.

13. There is no justification to continue a 10-year limit on recovering costs for post-2002 UOG from departing load, a limitation that does not exist for post-2002 PPAs or for pre-2002 UOG.

14. PCIA-eligible energy storage resources will be treated the same as other resources in the IOU portfolio, and will not be subject to a 10-year limitation on recovery.

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 for the Brown Power Index to reflect actual values realized in market transactions for the subject year should be adopted to ensure

that bundled and departing load customers pay equitably (i.e., pro rata) for non-RA, non-RPS 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 cap should be adopted to limit the change of the PCIA from one year to the next.

20. Starting with forecast year 2020, the cap level of the PCIA rate should be set at 0.5 cents/kWh more than the prior year's PCIA, differentiated by vintage.

21. The PCIA framework should allow for a net credit to departing load customers if utility portfolios provide positive net market value as demonstrated through actual recorded market transactions and realized revenues.

22. 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 ERRA balancing account. The year-end balances in the balancing accounts should be incorporated into the PCIA calculation for the following year.

23. The PCIA cap will not violate the cost-shifting provisions of Sections 365.2, 366.2 and 366.3 because any balances in the cap balancing account will be repaid to bundled customers with interest.

24. A trigger mechanism should be adopted in order to enable the Commission to act quickly to address undercollections in the cap balancing account.

25. 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, after phase two of this proceeding develops the necessary detail to analyze prepayment applications.

26. 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 renewable procurement standard (RPS) Adder, and (3) the resource adequacy (RA) adder.

    a. The Brown Power Index shall continue to be calculated using the methodology adopted in Decision (D.) 06-07-030.

    b. The RPS Adder shall be calculated using reported prices from purchases and sales of renewable energy by the investor-owned utilities (IOUs), Community Choice Aggregators (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 forecast only, the Energy Division shall use the most recently published Platts Portfolio Content Category (PCC) 1 REC index mid value ("California Bundled REC (Bucket 1)") as of November 1, 2018. The RPS Adder for each utility will be the sum of the Platts PCC 1 REC index value and its brown power index.

    c. The RA Adder shall be calculated using reported purchase and sales prices from IOU, CCA, and Electric Service Provider(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 Renewables Portfolio Standard Adder, and the Resource Adequacy 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 meet and confer to develop a uniform common spreadsheet template for the calculation of each of their PCIA rates and submit it to Energy Division within ten days of the effective date of this order.

4. 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.

5. The Commission establishes new transaction reporting requirements for all Load Serving Entities, including Community Choice Aggregators and Energy Service Providers, to ensure that the Renewables Portfolio Standard 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 Power Charge Indifference Adjustment 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, 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.

6. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, shall annually true-up their PCIA rates to reflect actual values realized in market transactions for the subject year for the Brown Power Index.

7. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each file a Tier 2 Advice Letter within 60 days to establish a Portfolio Allocation Balancing Account (PABA) with subaccounts for each vintaged portfolio to account for billed revenues, generation resource costs, net California Independent System Operator market revenues associated with energy and ancillary services, and revenues associated with the renewable energy Adder and the Resource Adequacy capacity in each vintaged portfolio.

8. Each utility shall also modify its Energy Resource Recovery Account (ERRA) balancing account and any other balancing accounts, as necessary, to be consistent with the PABA vintaged subaccount structure adopted in this decision. Only the year-end undercollection or overcollection related to the Brown Power Index in the vintaged PABA subaccounts shall be incorporated into the vintaged Power Charge Indifference Adjustment rate calculation in the following year, as part of each utility's ERRA forecast proceeding. The accuracy

of the entries in the vintaged PABA subaccounts shall be reviewed in each utility's annual ERRA compliance proceeding.

9. Power Charge Indifference Adjustment (PCIA) cap is adopted and shall be structured as specified below:

a. Starting in forecast year 2020, the cap level of the PCIA rate is set at 0.5 cents/kWh more than the prior year's PCIA, differentiated by vintage.

b. 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 Energy Resource Recovery Account balancing account.

c. 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.

10. A "trigger" mechanism for the PCIA cap is adopted and shall function as follows:

a. The PCIA trigger threshold is 10% of the forecast PCIA revenues.

b. If PG&E, SDG&E, or SCE reach 7%, and forecast that the balance will reach 10%, they shall, within 60 days, file expedited applications for approval in 60 days from the filing date when the balance reaches 7%.

c. The application shall include a projected account balance as of 60 days or more from the date of filing depending on when the balance will reach the 10% threshold.

d. The application shall propose a revised PCIA rate that will bring the projected account balance below 7% and maintain the balance below that level until January 1 of the

following year, when the PCIA rate adopted in that utility's ERRA forecast proceeding will take effect.

e. The IOUs are authorized to notify the Commission through advice letter filing, instead of expedited application, when the PCIA balance exceeds its trigger point and the IOU does not seek a change in rates, if the IOU reasonably believes the balance will self-correct below the trigger point within 120 days of filing. The advice letter filing shall include necessary documentation to support the IOU's conclusion that the PCIA balance will self-correct below the trigger point within 120 days and that a rate change is not needed.

11. Following further development of the prepayment option in phase two of this proceeding, Direct Access customers and Community Choice Aggregators, on behalf of their customers, shall be permitted to pre-pay their Power Charge Indifference Adjustment (PCIA) obligations, which shall be determined within the following framework:

a. The prepayment shall be based on a mutually acceptable forecast of that customer's future PCIA obligation;

b. 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;

c. The prepayment shall not be trued-up;

d. Once the prepayment has been made, the customer shall not receive any refunds if it returns to bundled service; and

e. After prepayment is finalized, the customer may switch among competitive retail sellers without incurring any new PCIA obligation.

12. Any prepayment agreement reached between counterparties pursuant to Ordering Paragraph 10 of this decision will be submitted for Commission approval by the utility counterparty via an application.

13. 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 Power Charge Indifference Adjustment obligations received pursuant to agreements reached pursuant to Ordering Paragraph 10 of this decision. Each utility shall describe its proposed disposition of the balances in these accounts in its advice letter.

14. A second phase of this proceeding is opened 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.

15. Rulemaking 17-06-026 remains open.

This order is effective today.

Dated October 11, 2018, at San Francisco, California.

MICHAEL PICKER
President
CARLA J. PETERMAN
LIANE M. RANDOLPH
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
Commissioners

I reserve the right to file a concurrence.

/s/ CLIFFORD RECHTSCHAFFEN
Commissioner

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) x Brown Adder + (RPS% V) x RPS Adder + RA Adder V } x (LOSSES)

Market Value V = MPB V x (Brown Energy V + RPS Energy V)

Or

Market Value V = (Brown Energy V x Brown Adder + RPS Energy V x RPS Adder + NQC V x RA Adder) x (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

This has been a highly contested and controversial matter, with strong and thoughtful engagement by many parties. It is not, as some have framed it, about undermining the Community Choice Aggregation programs (CCAs) or about enriching the utilities or their shareholders, who will not benefit from our decision here. Rather, this decision is about allocating costs between different ratepayers: CCA customers on one hand and customers of traditional utilities on the other. The Legislature has expressed a strong view that local governments should be able to form CCAs. Close to twenty CCAs are now up and running, giving them more control over their communities' energy mix. I will continue to support CCAs as healthy competition to the IOUs, as well as other options for customer choice that can drive positive change in electricity markets and help us meet our State's climate goals.

I support Commissioner Peterman's Alternate Proposed Decision (APD) because it updates what all parties agree has become a stale Power Charge Indifference Adjustment (PCIA) methodology, and moves us closer to the statutory directive to avoid cost shifts between bundled and departed customers. I agree with the inclusion of utility-owned generation built prior to 2002 and utility-owned generation costs for facilities built after 2002, without a time limit. These generation facilities were approved by the Commission as necessary to serve existing customers and meet statutory mandates, and the customers on whose behalf those costs were incurred should pay for them. Importantly, Phase 2 of this proceeding will have a strong focus on optimizing utility management of their portfolios, including consideration of shareholder responsibility for portfolio mismanagement, if such a finding is made.

While I support the APD as the correct result, I want to acknowledge the potential impacts the decision will have on CCAs. As a result of this decision, CCAs will face changes to the PCIA that will affect their overall budgets beyond what they may have planned for, including those CCAs that launched after careful deliberation. For some that are just starting, the decision may affect their ability to obtain financing, at least in the short run. The total impact of the decision, however, is limited by the fact that the PCIA is typically no more than 15% of a customer's bill, and therefore bill impacts for most customers should be relatively small.

I am encouraged that the decision adds a true-up to reflect real market costs for the brown power value of the resources included in the PCIA, and that our goal is to develop a true up process for Resource Adequacy and Renewables Portfolio Standard values by the end of 2019. In my view the sooner that this can be done, the better.

I also support the decision's cap on future PCIA increases of 0.5¢/kWh per year. I would have preferred that the cap start in 2019 rather than in 2020, to allow CCAs to more time to adjust to the new PCIA methodology. On the other hand, for most customers in at least PG&E and SCE territories, it appears that any bill increases next year from the PCIA will be less than the 0.5¢ cap anyway, so the delay in implementing the cap will not make a material difference.

I also would have preferred that we had been able to make further progress in developing a metric for including the value of GHG-free resources that may not be captured in the brown power component of the PCIA methodology, although I also recognize that we lacked market information to guide us here. It is my hope and expectation that Phase 2 will seriously consider developing such a metric.

In the end, this decision should provide much greater certainty for both utility customers and departing customers, and a path forward in Phase 2 for finding more durable, market-based solutions to resolve these issues.

I respectfully concur in the decision.

Clifford Rechtschaffen, Commissioner