

Docket No.: R.23-01-007

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Witnesses: Brian Dickman

**OPENING TESTIMONY OF BRIAN DICKMAN
ON BEHALF OF
THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION**

**RULEMAKING IMPLEMENTING SENATE BILL 846 CONCERNING
POTENTIAL EXTENSION OF DIABLO CANYON POWER PLAN OPERATIONS**

TABLE OF CONTENTS

I. INTRODUCTION AND SUMMARY OF TESTIMONY 1

II. CUSTOMERS PAYING FOR EXTENDED OPERATIONS SHOULD RECEIVE THE BENEFITS OF DCPD’S RA AND GHG-FREE ATTRIBUTES3

 A. Costs And Benefits of DCPD Extended Operations Should Be Aligned and Fairly Allocated to Customers4

 1. SB 846 Shifts The Financial Risk of Extending DCPD Operations to Customers, and They Should Benefit Accordingly4

 2. The Commission Should Follow The CAM Model To Allocate The Costs and Benefits of DCPD Extended Operations5

 B. DCPD RA Capacity Should Be Allocated to LSEs7

 1. Allocating DCPD RA To LSEs Will Avoid Artificially Understating Resources Available in A Constrained Market7

 2. Allocating DCPD’s Attributes Will Not Impact The State’s Long-Term Planning Goals 14

 C. The Commission Should Direct PG&E To Continue Offering Voluntary Allocations of DCPD’s GHG-Free Attributes To LSEs 17

III. PG&E SHOULD BE REQUIRED TO FILE A STAND-ALONE APPLICATION SEEKING APPROVAL OF THE FORECASTED NET COSTS OF DCPD CONTINUED OPERATION ON AN ANNUAL BASIS20

 A. A New Annual Application for The Recovery of The Forecasted Costs of DCPD Extended Operations Should Be Structured in The Same Manner As PG&E’s Annual ERRRA Forecast Proceeding20

 B. PG&E’s DCPD Forecast Application Should Include Detailed Support of The Projected Net Costs to Be Charged Customers23

IV. THE NET COSTS OF DCPD EXTENDED OPERATIONS SHOULD BE TRACKED IN A NEW BALANCING ACCOUNT AND RECOVERED THROUGH A NEW NBC INCLUDED IN IOU DELIVERY RATES29

 A. PG&E Has Already Developed A New Balancing Account to Record The Net Costs of DCPD Extended Operations30

 B. A New NBC Should Be Created and Charged to Customers in Jurisdictional IOUs’ Delivery Rates30

ATTACHMENTS

- ATTACHMENT A:** Curriculum Vitae of Brian Dickman
- ATTACHMENT B:** Select Data Request Responses

1 **I. INTRODUCTION AND SUMMARY OF TESTIMONY**

2 The California Community Choice Association (**CalCCA**) presents this opening
3 testimony in the *Rulemaking Implementing Senate Bill 846 (SB 846) Concerning Potential*
4 *Extension of Diablo Canyon Power Plant Operations*¹ (**DCPP OIR**). This testimony has
5 been prepared on behalf of CalCCA by Brian Dickman, Partner, NewGen Strategies and
6 Solutions, LLC. Mr. Dickman’s qualifications are set forth in Attachment A.

7 CalCCA has a particular interest in the Diablo Canyon Power Plant (**DCPP**)
8 extended operations and this DCPP OIR because SB 846 directs that certain costs of
9 extended operations will be recovered from customers of all load-serving entities (**LSEs**)
10 subject to the California Public Utilities Commission’s (**Commission**) jurisdiction,
11 including customers of community choice aggregators (**CCA**) that are members of
12 CalCCA. This testimony presents CalCCA’s proposals on certain issues falling within
13 Phase 1: Track 2 as established in the April 6, 2023, Assigned Commissioner’s Scoping
14 Memo and Ruling² (**OIR Scoping Ruling**). Specifically, CalCCA’s proposals address
15 three scoping items, listed below:³

- 16 1. If the Commission directs and authorizes extended operations at DCPP, what
17 are the new processes to authorize annual recovery of all reasonable DCPP
18 extended operation costs and expenses on a forecast basis, including allocation
19 of forecast costs among Commission-jurisdictional load-serving entities.
- 20 2. Whether additional cost recovery mechanisms, agreements, plans, and/or
21 orders are needed prior to the current retirement dates for Diablo Canyon
22 Units 1 and 2 (i.e., in 2024 and 2025, respectively).

¹ Rulemaking (**R.**) 23-01-007, *Rulemaking Implementing Senate Bill 846 Concerning Potential Extension of Diablo Canyon Power Plant Operations* (Jan. 12, 2023):

<https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M501/K368/501368884.PDF>.

² R.23-01-007, *Assigned Commissioner’s Scoping Memo and Ruling* (Apr. 6, 2023) (**Scoping Ruling**), at 5-6: <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M505/K462/505462882.PDF>.

³ CalCCA reserves the right to respond or comment on other matters within the scope of this proceeding at the appropriate time as included in the OIR Scoping Ruling or other scoping rulings during the course of the proceeding.

- 1 3. Whether and how the benefits of extended operations, including resource
2 adequacy and greenhouse gas-free attributes, should be allocated among the
3 LSEs and customers paying for extended operations.

4 As described further in my testimony, CalCCA recommends the following:

- 5 • The Commission should adopt the same process currently used for resources
6 subject to the Cost Allocation Mechanism (**CAM**) to allocate DCPD's resource
7 adequacy (**RA**) capacity to all LSEs contributing toward cost recovery. Capacity
8 should be allocated based on each entity's proportional contribution to the group's
9 combined 12-month coincident peak.
- 10 • The Commission should require DCPD's green-house gas (**GHG**)-Free attributes
11 be made available to all LSEs contributing toward cost recovery through a
12 voluntary allocation, similar to the current 'interim' approach approved for Pacific
13 Gas and Electric Company's (**PG&E**) large hydroelectric and nuclear facilities.
- 14 • The Commission should require PG&E to file a stand-alone application seeking
15 approval of the forecasted net costs of DCPD continued operations on an annual
16 basis. PG&E should be required to present detailed projections of all DCPD costs
17 and revenues in a format similar to the information provided in its general rate
18 case (**GRC**) and Energy Resource Recovery Account (**ERRA**) proceedings.
- 19 • Net DCPD costs that are to be recovered from customers of all jurisdictional LSEs
20 in the state should be allocated to investor-owned utility (**IOU**) service territories
21 based on the contribution to the group's combined 12-month coincident peak.
- 22 • The Commission should require PG&E to track the net costs of DCPD extended
23 operations in a new balancing account and recover those costs through a new non-
24 bypassable charge (**NBC**) included in each IOU's delivery rates.
- 25 • In sum, the ratemaking process for DCPD costs would be:
- 26 1. PG&E prepares an annual DCPD Forecast Application that is similar to
27 but separate from the ERRA Forecast Application.
- 28 2. A Commission decision in the DCPD Forecast Application sets the level of
29 the revenue requirement to be collected through the DCPD-specific NBC
30 in each IOU's service territory.
- 31 3. That revenue requirement is translated to a \$/kWh charge for eligible
32 customers in an IOU's service territory in November and December via
33 each IOU's consolidated rate change advice letter filing.

1 **II. CUSTOMERS PAYING FOR EXTENDED OPERATIONS SHOULD RECEIVE**
2 **THE BENEFITS OF DCPD'S RA AND GHG-FREE ATTRIBUTES**

3 There are two ways for the Commission to ensure customers benefit from the
4 value of a resource's attributes. *First*, the Commission might assign customers a credit
5 against retail rates. *Second*, the Commission might allocate resource attributes among the
6 LSEs serving those customers.

7 Currently, the Commission follows the first approach for DCPD. The costs to own
8 and operate DCPD are recovered from bundled and departed load customers in PG&E's
9 service territory through Power Charge Indifference Adjustment (PCIA) rates, which are
10 structured to recognize the value of DCPD's generation-related attributes as a credit
11 against retail rates. PG&E charges customers for DCPD's above-market costs, calculated
12 as the cost of the resource less the market value of its energy and capacity. Generation
13 output is sold into the CAISO market, and the market revenue is netted against DCPD
14 costs. The value of DCPD RA that PG&E retains to meet a portion of its bundled
15 customer RA requirement is reflected as a credit against DCPD costs and reduces PCIA
16 rates for customers. Revenue received from sales of DCPD RA, if any, to third parties is
17 also credited against DCPD costs.

18 Going forward, costs associated with extended operations at DCPD will not be
19 recovered through the PCIA. Instead, SB 846 allows PG&E to charge customers a new
20 NBC to recover all "reasonable costs and expenses necessary to operate [DCPD] beyond
21 the current expiration dates,"⁴ net of market revenue from DCPD operation. Under the
22 cost recovery regime described in SB 846, customer rates will no longer reflect a credit

⁴ Cal. Pub. Util. Code § 712.8(h)(1).

1 for the value of RA, nor will they reflect a credit to recognize the value of the GHG-free
2 attribute of the generation.

3 Consequently, the Commission would need to follow the second method to ensure
4 that customers that pay the cost of continued DCPP operation realize the value of
5 continued operations.

6 **A. Costs And Benefits of DCPP Extended Operations Should Be Aligned and**
7 **Fairly Allocated to Customers**

8 **1. SB 846 Shifts The Financial Risk of Extending DCPP Operations to**
9 **Customers, and They Should Benefit Accordingly**

10 SB 846 alters the cost recovery framework for DCPP during extended operations
11 and shifts the financial risk of extending operations to customers throughout California.
12 Pursuant to SB 846, PG&E will assess several new charges to customers to compensate
13 PG&E shareholders “in lieu of a rate-based return on investments and in acknowledgment
14 of the greater risk of outages in an older plant.”⁵ Specifically, PG&E will collect
15 \$13.00/MWh for each MWh generated by DCPP, plus a fixed payment of \$100 million
16 (\$50 million per unit) annually. Together, these fees collected in lieu of a rate-based return
17 total approximately \$320 million⁶ per year, compared to \$143 million in annual return on
18 rate base proposed by PG&E in its 2023 GRC. SB 846 entitles PG&E to recover from
19 customers the cost of replacement power during unplanned outage periods, *even if the*
20 *unplanned outage is the result of a failure by PG&E to meet the reasonable manager*
21 *standard.*⁷ In fact, PG&E is allowed to charge all customers up front to fund a \$300
22 million liquidated damages balancing account that can be used to cover the cost of

⁵ Cal. Pub. Util. Code § 712.8(f)(5) and § 712.8(f)(6).

⁶ Volumetric payments estimated based on actual generation output during 2021.

⁷ Cal. Pub. Util. Code § 712.8(i)(1).

1 replacement power during these imprudent outages. It is not reasonable for customers to
2 bear all of these costs, including more than doubling the payments to PG&E shareholders,
3 without realizing the corresponding benefits of the plant's extended operation.

4 **2. The Commission Should Follow The CAM Model To Allocate The Costs**
5 **and Benefits of DCPD Extended Operations**

6 SB 846 extended the life of the DCPD plant for the benefit of all California's electric
7 customers while designating a single IOU, PG&E, as the operator. Public Resources Code
8 Section 25548.7 states, "Continued operation of the Diablo Canyon powerplant as provided
9 in this chapter is in all respects for the welfare and the benefit of the people of the state..."
10 Based on this rationale, SB 846 also alters the cost recovery framework for DCPD during
11 extended operations. SB 846 entitles PG&E to recover the reasonable and necessary costs to
12 operate DCPD beyond the current expiration dates, net of market revenue from DCPD
13 operation. With limited exceptions, SB 846 specifies that DCPD extended operations costs
14 are to be recovered from customers of all jurisdictional LSEs in California.

15 The rationale and framework for extending DCPD operations described in SB 846
16 is similar to the CAM concept originally established by the Commission in Decision (D.)
17 06-07-029. The Commission adopted the CAM as a mechanism to streamline
18 procurement of critical new resources for the benefit of multiple customer groups (e.g.,
19 bundled and unbundled customers). In D.06-07-029 the Commission stated, "[We] are
20 adopting a cost-allocation mechanism... that allows the advantages and costs of new
21 generation to be shared by all benefiting customers in an IOU's service territory. We
22 designate the IOUs to procure this new generation. The LSEs in the IOU's service
23 territory will be allocated rights to the capacity that can be applied toward each LSE's
24 RA requirements. The LSE's customers receiving the benefit of this additional capacity

1 pay only for the net cost of this capacity, determined as a net of the total cost of the
2 contract minus the energy revenues associated with dispatch of the contract.”⁸

3 As directed by the Commission, IOUs procure CAM resources for the benefit of
4 all customers in their respective service territories. CAM resource costs, net of revenues
5 from selling energy and ancillary services into the California Independent System
6 Operator (CAISO) market, are then recovered from all customers in each IOU’s service
7 territory through a volumetric NBC. PG&E’s CAM NBC is known as the New System
8 Generation Charge (NSGC).

9 Recognizing the similarities between CAM and DCPD extended operations, a
10 fundamental principle that should be followed here is that the allocation of costs and
11 benefits should be aligned and fairly distributed to customers. When establishing the
12 CAM, the Commission determined, “[a]ll RA counting benefits and net costs are spread
13 to the LSEs whose customers are allocated costs based on share of 12-month coincident
14 peak, adjusted on a monthly basis to facilitate load migration. The contract costs paid and
15 RA benefits received by [departed load] and bundled customers should be based on a
16 share basis equal to the credit share received.”⁹

17 The Commission should allocate the costs and benefits of DCPD extended
18 operations the same way it allocates the costs and benefits of CAM resources.
19 Specifically, net costs that PG&E will recover from customers of all jurisdictional LSEs
20 in the state, per SB 846, should be allocated to IOU service territories based on the
21 contribution to the group’s combined 12-month coincident peak.¹⁰ As I describe later in

⁸ D.06-07-029 at 7.

⁹ *Id.* at 31.

¹⁰ The 12-month coincident peak allocation should be consistent with the RA attribute allocation prepared by Energy Division to match costs and benefits.

1 my testimony, each IOU would recover the allocated DCPD costs from all customers in
2 its service territory through a new NBC included in delivery rates.

3 Each Commission-jurisdictional LSE should also receive a proportional share of
4 DCPD's RA attributes, based on a share of the 12-month coincident peak. At a high level,
5 following the CAM procedures already in place for the Commission's RA compliance
6 program, Energy Division should include an allocation of DCPD RA capacity in the RA
7 template for each LSE, reducing the System RA requirement for each LSE by its share of
8 DCPD capacity for compliance periods during extended operations. Below, I describe in
9 more detail how the Commission should allocate DCPD RA to LSEs.

10 **B. DCPD RA Capacity Should Be Allocated to LSEs**

11 **1. Allocating DCPD RA To LSEs Will Avoid Artificially Understating**
12 **Resources Available in A Constrained Market**

13 California LSEs face a constrained RA market, despite the fact that DCPD
14 remains in operation. Several different analyses have now concluded that, unless recent
15 weather patterns shift back to "normal," to avoid significant capacity shortages until
16 unprecedented amounts of new resources can be brought online, DCPD should continue
17 to operate. As LSEs seek to procure sufficient resources to meet their obligations under
18 the Commission's Resource Adequacy program they are *already* faced with year-over-
19 year price increases, price spikes in high demand summer months, and a lack of capacity
20 available in the market. Ignoring DCPD in the RA market, especially when it is still
21 operating and providing system capacity, will only exacerbate the market constraints and
22 artificially increase rates.

23 The California Energy Commission (CEC) staff report on Diablo Canyon Power
24 Plant Extension (**CEC Report**) published in March 2023 recommends the CEC determine

1 that it is prudent for the state to pursue extension of DCPD due to the risk that sufficient
2 resources may not be built in time to reach procurement targets ordered by the Commission
3 and to address potential grid demands in extreme heat events.¹¹ The CEC Report relies on a
4 deterministic resource stack analysis to evaluate capacity needs through 2032 assuming
5 DCPD units are retired. The analysis indicates that under planning, or ‘normal,’
6 circumstances the CAISO market should have sufficient capacity to meet demand.
7 However, the report demonstrates that deviations from normal conditions, such as the heat
8 waves experienced in California during 2020 and 2022, will put significant strain on the
9 available capacity and result in resource shortages during critical summer months.

10 The CEC also recognizes that its analysis relies on aggressive assumptions,
11 including the “ability to build new clean energy resources at a pace not seen before and in
12 the face of supply chain, interconnection, and permitting delays.”¹² In fact, when the CEC
13 considered resource delays and summer temperatures equivalent to those experienced in
14 2022, the stack analysis demonstrates anticipated capacity shortfalls exceeding 2,000
15 MW through 2029.

16 The relevance of this conclusion is underscored by the Joint Agency Reliability
17 Planning Assessment (**Joint Agency Report**) published by the CEC and the Commission
18 in February 2023. The Joint Agency Report details that climate driven events had a
19 significant impact on CAISO system reliability *in each of the last three years*:

20 Climate change is causing substantial variability in weather patterns
21 and an increase in climate-driven natural disasters, which is
22 resulting in more challenges to maintaining grid reliability. In 2020,
23 a west-wide heat event resulted in rotating outages August 14 and
24 15. In 2021, dry conditions resulted in a wildfire in Oregon that
25 impacted transmission lines that California depends on for

¹¹ CEC Report at. ii.

¹² *Id.* at 25.

1 reliability, resulting in a loss of 3,000 megawatts (MW) of imports
2 to the California Independent System Operator (California ISO)
3 territory and 4,000 MW of overall import capacity to the state. In
4 2022, California experienced record high temperatures between
5 August 31 and September 9. On September 6, 2022, the California
6 ISO recorded a new record peak load at 52,061 MW, nearly 2,000
7 MW higher than the previous record, despite significant efforts to
8 reduce load during this peak period.¹³

9 As part of its reliability assessment, the Joint Agency Report concluded that if DCPD is
10 retired by 2025, capacity shortfalls of 500 MW to 3,800 MW are expected between 2023
11 and 2027 unless the heat events that occurred in 2020 and 2022 are aberrations and not
12 part of the ‘new normal’ Californians face.¹⁴

13 The CEC Report also acknowledges the shortcomings of a deterministic stack
14 analysis approach, stating, “It is difficult to articulate the probability of the outcomes
15 contained in the results from a deterministic stack approach. Thus, the actual probability of
16 the outage risks associated with different supply and demand balances are uncertain,
17 especially when looking far into the future.”¹⁵ Notably, the CAISO conducted a probabilistic
18 production cost modeling analysis to support the Commission IRP process, inform summer
19 preparedness activities, and support the CEC’s evaluation of the prudence of extending
20 DCPD operation. The CAISO analysis found capacity shortages between approximately 750
21 MW and 1,285 MW are expected in 2025 and 2026, even after considering new resource
22 additions identified in the IRP or as ordered by Commission procurement decisions.¹⁶

23 CalCCA witnesses Eric Little and Andrew Mills sponsor testimony in this
24 proceeding to present an analysis of the constrained RA market published by CalCCA in

¹³ Joint Agency Reliability Planning Assessment at 7 (Feb. 2023).

¹⁴ *Id.* at 50.

¹⁵ CEC Report at 16.

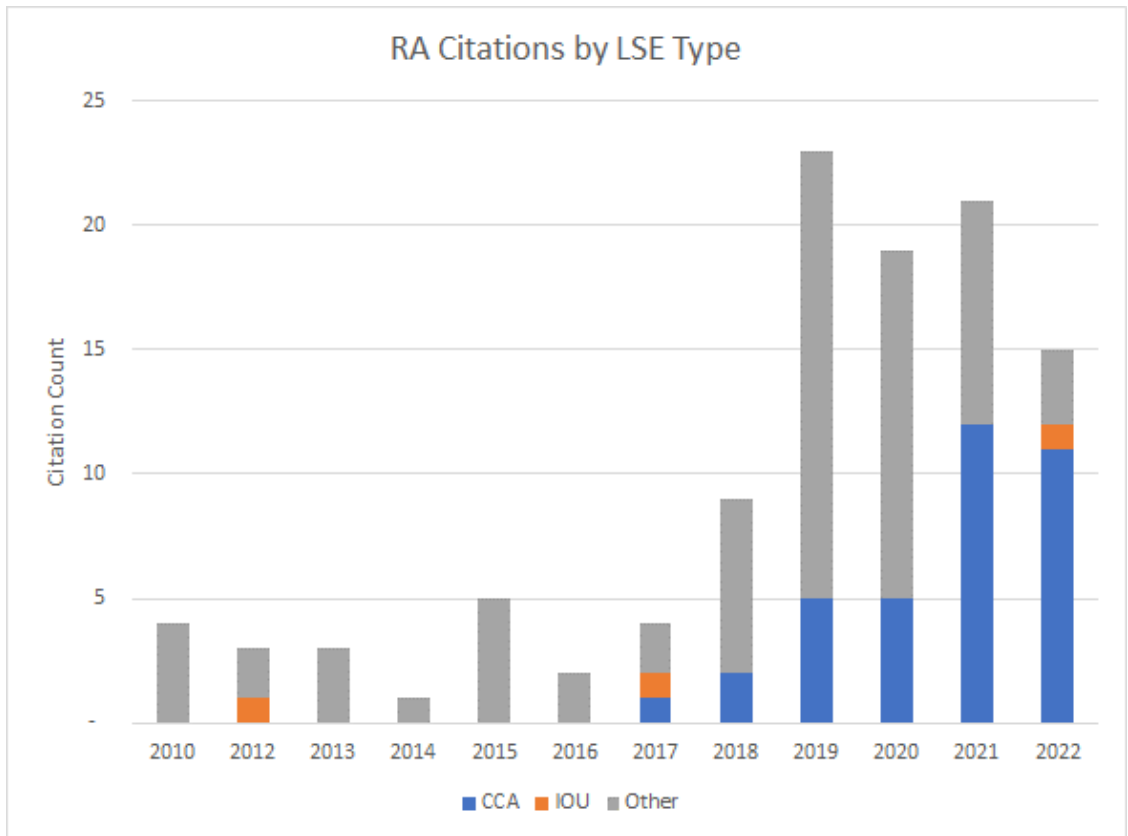
¹⁶ February 2, 2023 Letter to CEC Vice Chair, available at <http://www.aiso.com/Documents/Jan2-2023-Letter-CaliforniaEnergyCommissionViceChair-CAISOReliabilityModeling.pdf>.

1 March 2023 (**CalCCA Stack Analysis**), updated to include recent information regarding
2 the status of the RA market. The CalCCA Stack Analysis concurs with the CEC's
3 analysis, finding that certain conditions similar to those considered in the CEC analysis
4 are contributing to RA shortfalls including extreme weather conditions, declining hydro
5 resource availability due to drought, delays bringing new resources online, increasing
6 capacity needs across the Western region, and restrictive regulatory requirements. Based
7 on its updated analysis, CalCCA anticipates a 433 MW shortage for 2023, growing to a
8 1,258 MW shortage in 2025.

9 All of these assessments point to the same conclusion: capacity is scarce, it will
10 remain scarce, and DCPD provides needed System RA. One symptom of the constrained
11 RA market is that many LSEs have been unable to meet their System RA requirements
12 despite being willing to pay. The Enforcement Actions Spreadsheet updated by the
13 Consumer Protection and Enforcement Division in February 2023 tracks RA citations
14 issues to various entities from October 2009 through November 2022. As shown in
15 Figure 1, there was a sharp increase in the number of citations in 2019, and elevated
16 levels continued through 2022.

1

Figure 1



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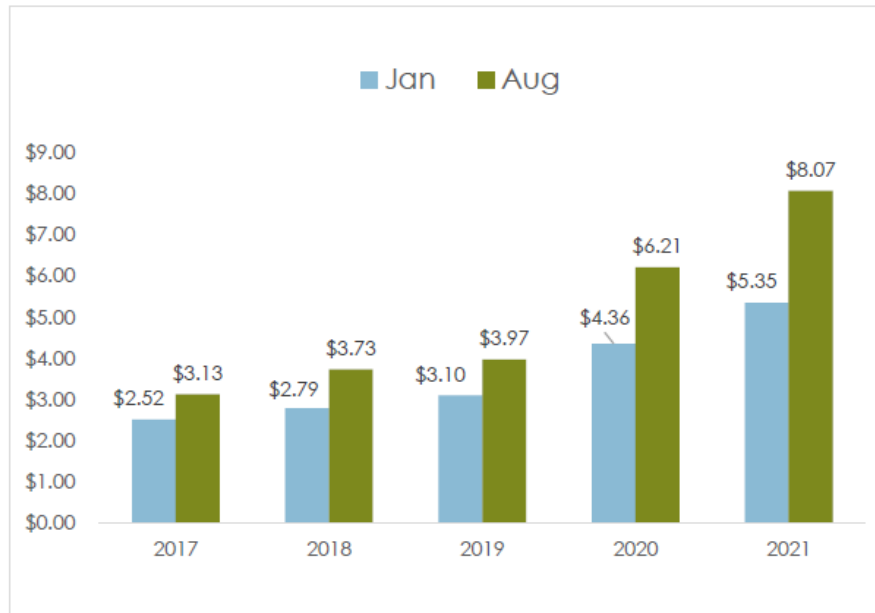
Another symptom of the constrained market is the steadily increasing price of System RA. Figure 2 below reproduces Figure 4 from the 2021 Resource Adequacy Report,¹⁷ showing the rise in RA prices from 2017 to 2021.

¹⁷ 2021 Resource Adequacy Report: https://webproda.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2021_ra_report_040523.pdf.

Figure 2

2021 Resource Adequacy Report

Figure 4: Weighted Average Price of System RA (\$/kW-month), January and August 2017- 2021



Source: 2017-2021 price data submitted by LSEs.

2

3 As the figure shows, Energy Division’s 2021 Resource Adequacy Report illustrates that the
 4 average price of System RA transactions executed for August 2021 was 158% higher than
 5 for August 2017.¹⁸ The RA market price benchmarks calculated by Energy Division in
 6 September 2022 report that System RA prices in 2022 averaged \$8.11/kW-month over the
 7 entire year, and the forecast for average System RA prices in 2023 is \$7.39/kW-month.

8

9

10

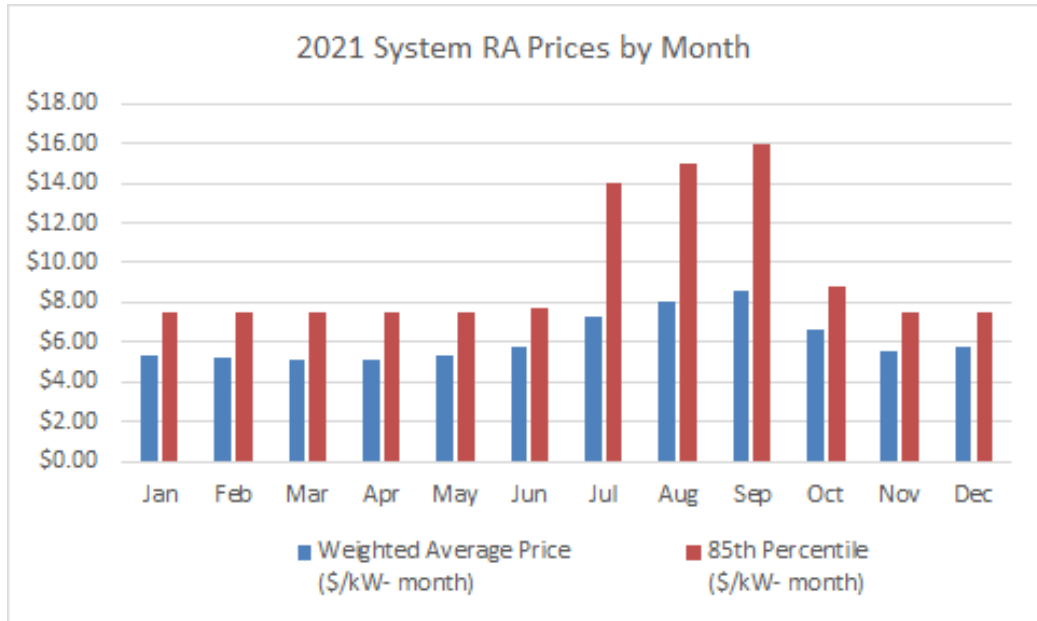
Energy Division’s data also shows that variation in RA prices during 2021 was
 significantly greater during high-demand summer months relative to other periods; prices
 for 15 percent of transactions exceeded \$14/kW-month during July – September 2021.¹⁹

¹⁸ *Id.* at 28-29.

¹⁹ *Id.* at 27-28.

1 The CalCCA Stack Analysis concurs, finding “Resources that garnered \$3.63 kilowatt
 2 (kW)-month in 2019 rose to prices as high as the mid-\$40 kW-month for summer 2023
 3 and are increasingly unavailable at any price.”²⁰ Figure 3 below presents Energy
 4 Division’s monthly price data for 2021 in graph form.

5 **Figure 3**



6
 7 Price spikes such as these in the short-term RA market simply create a windfall for
 8 existing generation owners at the expense of retail consumers. There is no incremental
 9 reliability benefit to the system from these increased costs.

10 Withholding DCP’s 2,280 MW of capacity from the RA market would worsen the
 11 market constraints causing such spikes. Further squeezing the RA market by ignoring DCP
 12 will increase costs for customers by over \$200 million²¹ annually as they are required to
 13 procure RA rather than count the DCP capacity they pay for during extended operations.
 14 There will be no incremental reliability benefit accompanying this dramatic rate increase.

²⁰ CalCCA Stack Analysis at 2. Internal citation omitted.
²¹ 2,280 MW * \$7.39/kW-month * 1,000 * 12 = \$202.2 million.

1 **2. Allocating DCPD’s Attributes Will Not Impact The State’s Long-Term**
2 **Planning Goals**

3 Regardless of the cause of the scarcity in the RA market, and the resulting high
4 prices, California will need more resources to contribute to meeting the Commission’s
5 RA requirements until new zero-carbon reliability resources can be built. Recognizing
6 this need, SB 846 describes the purpose of extending DCPD operation: “Preserving the
7 option of continued operations of the Diablo Canyon powerplant for an additional five
8 years beyond 2025 may be necessary to improve statewide energy system reliability and
9 to reduce the emissions of greenhouse gases while additional renewable energy and zero-
10 carbon resources come online, *until those new renewable energy and zero-carbon*
11 *resources are adequate to meet demand.*”²²

12 In Reply Comments on the Order Instituting Rulemaking to establish this
13 proceeding, PG&E argued, “RA allocation to reduce RA compliance procurement activity is
14 in conflict with Legislative direction that the state act with urgency to bring clean
15 replacement energy to support reliability and achieve California’s landmark climate
16 goals.”²³ This position ignores the difference between the Integrated Resource Planning
17 (IRP) process and the Commission’s procurement focused decisions, which drive the
18 construction of new resources, and RA compliance, which drives near-term LSE
19 procurement to optimize the use of already-existing resources. California’s IRP process for
20 Commission-jurisdictional LSEs comprises two parts: 1) identifying an optimal portfolio for
21 meeting state policy objectives, and 2) aggregating the LSEs’ collective efforts for planned

²² PRC § 25548(b). Emphasis added.

²³ R.23-01-007, *Reply Comments of Pacific Gas And Electric Company (U 39 E) on Administrative Law Judge’s Ruling Requesting Comments on Phase 1: Track 1 Issues* (May 31, 2023) (**PG&E Reply Comments**), at 8: <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M510/K286/510286991.PDF>.

1 and contracted resources to compare to the optimal system. The Commission IRP process
2 requires jurisdictional LSEs to submit plans every two years to ensure they can meet GHG
3 reduction targets while maintaining system reliability.²⁴ In the IRP planning track, the
4 Commission adopts a preferred system plan identifying the optimal portfolio spanning over
5 a ten-year forecast period, and then sets requirements for LSEs to plan toward that future.
6 “To the extent that the CPUC orders procurement in the IRP proceeding, it is generally to
7 meet a reliability or GHG reduction need identified in the planning track.”²⁵

8 The purpose of the Commission’s RA program is to ensure capacity resources are
9 contracted for and available to meet California demand in the short term. The
10 Commission describes that the RA program “guides resource procurement and promotes
11 infrastructure investment by requiring that LSEs procure capacity so that capacity is
12 available to the CAISO when and where needed.”²⁶ The RA program has two types of
13 filings: annual and monthly. On an annual basis, LSEs are required to demonstrate that
14 they have procured 90% of their System RA obligation for the five summer months of the
15 coming compliance year. On a monthly basis, LSEs must demonstrate they have procured
16 100% of their monthly System RA obligation. LSEs can demonstrate compliance with
17 their RA obligations either through long-term procurement (i.e., pursuant to the IRP and
18 Commission procurement decisions) or through purchases of RA capacity from third
19 parties in the bilateral market.

20 PG&E also argued in its Reply Comments that allocated RA capacity from DCP
21 to LSEs for RA compliance purposes “would in effect provide a procurement reprieve to

²⁴ Joint Agency Report at 25.

²⁵ *Id.* at 26.

²⁶ <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage>, accessed May 23, 2023.

1 LSEs, thus, countering the incentive for LSEs to engage in incremental procurement to
2 improve reliability of the state’s electrical system...[T]he Commission is currently
3 considering extended operation through 2030 and, if LSEs assume RA and GHG-free
4 energy from DCPD through 2030, that could impact whether they enter into contracts
5 today for delivery in the late 2020s.”²⁷

6 This is not true. The Commission’s IRP process and ensuing procurement
7 decisions will continue to dictate the pace of long-term resource procurement even if
8 DCPD RA counts toward jurisdictional LSEs’ RA compliance obligations in the near
9 term. SB 846 prohibits LSEs from including DCPD energy, capacity, or GHG-free
10 attributes in their resource planning and requires the state to continue to act with urgency
11 to bring clean replacement energy online.²⁸ As discussed earlier, however, long-term
12 resource planning differs from short-term RA compliance procurement. Furthermore,
13 LSEs are already acting to bring new capacity online from 2021 through 2026 pursuant to
14 procurement requirements in D.19-11-016 and D.21-06-035, although the Commission
15 recognized in D.23-02-040 challenges related to procuring long-lead time resources. The
16 Joint Agency Report confirms, “Between 2020 and late 2022, the CPUC’s IRP
17 procurement orders and prior LSE procurement resulted in over 11,000 MW of new
18 nameplate energy resources, equivalent to over 6,000 MW of new Net Qualifying
19 Capacity (NQC) that can count toward RA capacity obligations.”²⁹

20 Even after accounting for resource additions ordered or planned through the IRP
21 process, the Joint Agency Report found that, under extreme weather conditions, capacity

²⁷ PG&E Reply Comments at 8-9.

²⁸ PRC § 25548(c).

²⁹ Joint Agency Report at 29.

1 shortfalls are expected to continue throughout DCPD extended operations. Factoring in
2 possible delays in planned procurement due to supply chain challenges only increases the
3 expected shortfalls. In short, the risk of insufficient or delayed resource procurement
4 *drives* the need to extend DCPD operations; extension of operations is not the *cause* of
5 delayed procurement.

6 DCPD RA should be allocated among all LSEs whose customers will pay for the
7 cost of extended operations to avoid artificially understating available resources in an
8 already constrained RA market. The IRP and Commission procurement directives will
9 ensure new resources will be built over the long term. The Commission designed the RA
10 program to ensure resources are under contract and available to meet peak demand in the
11 short term. Removing DCPD from the pool of resources available to count toward System
12 RA requirements will artificially constrict the market, despite DCPD's continued operation.

13 **C. The Commission Should Direct PG&E To Continue Offering Voluntary**
14 **Allocations of DCPD's GHG-Free Attributes To LSEs**

15 In R.17-06-026, the Commission has been evaluating whether it should
16 incorporate a credit for GHG-Free attributes into the PCIA to reflect the premium value
17 of GHG-Free energy as an offset to resource costs. Analysis of historical market
18 transaction data led Energy Division to conclude in September 2022 that "there is
19 currently a premium for GHG-Free resources" in California and to recommend the value
20 be recognized in the PCIA.³⁰ GHG-Free energy has value to LSEs because it impacts

³⁰ R.17-06-026, *Administrative Law Judge's Ruling Requesting Comments on GHG-Free Resources Staff Proposal and Other Issues* (Sept. 12, 2022), Attachment A, "GHG Free Data Analysis and Staff Proposal" (**September 12 Staff Proposal**), at 5:
<https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=496874129>.

1 LSEs’ carbon intensity for the purpose of their Power Content Label.³¹ Receiving GHG-
2 Free energy also impacts LSEs’ marketing efforts. On May 4, 2023, the Commission
3 issued a proposed decision in R.17-06-026 (**PCIA OIR Proposed Decision**) finding that
4 there was sufficient data to support a “heightened value for GHG-Free resources, which
5 can be attributed to [Power Content Label] value or meeting an individual LSEs’ GHG
6 reduction goals more broadly.”³²

7 The Commission should require PG&E to offer allocations of DCP’s GHG-Free
8 attributes to LSEs whose customers will pay for extended operations. Doing so simply
9 requires the Commission to continue the *status quo*, with a few modifications. Resolution
10 E-5111 approved PG&E’s current ‘interim’ allocation process which allocates GHG-Free
11 attributes from resources in PG&E’s PCIA portfolio.³³ PG&E offers LSEs within its
12 service territory an allocated amount of GHG-Free energy generated by specified
13 facilities corresponding to each LSE’s “Allocation Ratio.”³⁴ Once a year PG&E offers
14 each LSE its Allocation Ratio which, after execution of a Sales Agreement, corresponds
15 to an allocated quantity of GHG-Free energy sold to the LSE during the delivery year.
16 Under this framework, LSEs that accept the allocations may report the corresponding

³¹ Under the CEC’s Power Source Disclosure program, LSEs must disclose to their customers the mix of sources used to provide electricity service during the previous calendar year, and the greenhouse gas emissions intensity of their portfolio. The annual disclosure is made on an LSE’s “Power Content Label.”

³² R.17-06-026, Proposed *Decision Addressing Greenhouse Gas-Free Resources, Long-Term Renewable Transactions, Energy Index Calculations, and Energy Service Providers’ Data Access* (issued May 4, 2023), at 17: <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M508/K069/508069560.PDF>.

³³ Allocation of PG&E’s GHG-Free resource was first approved in Resolution E-5046, which adopted Appendix P to PG&E’s 2014 Bundled Procurement Plan specifying the terms under which GHG-Free attributes would be allocated. Resolution E-5111 approved several modifications to Appendix P based on experience with the allocation process to that point.

³⁴ The Allocation Ratio is defined as the LSE’s monthly load forecast used in PG&E’s ERRA Forecast Application compared to the total forecasted load for customers responsible for the costs of the resources. Because allocation of DCP’s GHG-Free attributes during extended operations would involve LSE outside of PG&E’s service territory, the CEC’s California Energy Demand forecast, as updated annually, could be used to determine the applicable Allocation Ratio.

1 GHG-Free energy on their annual Power Content Label under the CEC’s Power Source
2 Disclosure Program.

3 PG&E should continue to offer voluntary allocations of the GHG-free attributes
4 associated with DCP. ³⁵ PG&E’s existing allocation process needs only minor
5 modifications to conform to DCP’s extended operations. PG&E should modify its
6 Bundled Procurement Plan (**BPP**) Appendix P to accommodate an annual allocation and
7 offer process for DCP as a stand-alone specified resource. Under my proposal, PG&E
8 would calculate DCP GHG-Free generation separate from PG&E’s other resources, and
9 would expand eligibility to receive an allocation of DCP generation to all California
10 LSEs subject to the DCP NBC, including PG&E and other IOUs. LSEs can confirm
11 their acceptance of an allocation by executing a sales agreement with PG&E subject to
12 the conditions in PG&E’s BPP Appendix P. Unclaimed allocations, if any, would be
13 unused for that delivery year and would not be reported on any individual LSE PCL or
14 other communications.

15 Continuing voluntary allocations is a reasonable approach to ensuring that cost-
16 responsible customers continue to have the option of receiving the benefits of DCP’s
17 GHG-free energy.

³⁵ The PCIA OIR Proposed Decision adopts a GHG-Free allocation or Market Price Benchmark process for large hydroelectric resources, and allows, but does not require, the IOUs to continue to offer allocations of GHG-Free attributes from PCIA-eligible nuclear resources on a voluntary, annual basis. The PCIA OIR Proposed Decision ties this framework to the PCIA and eliminates it once the PCIA sunsets. It does not address the continuation of voluntary allocation under a non-PCIA rate mechanism.

1 **III. PG&E SHOULD BE REQUIRED TO FILE A STAND-ALONE APPLICATION**
2 **SEEKING APPROVAL OF THE FORECASTED NET COSTS OF DCP**
3 **CONTINUED OPERATION ON AN ANNUAL BASIS**

4 **A. A New Annual Application for The Recovery of The Forecasted Costs of DCP**
5 **Extended Operations Should Be Structured in The Same Manner As PG&E’s**
6 **Annual ERRA Forecast Proceeding**

7 PG&E currently establishes the annual cost to operate DCP through a
8 combination of its GRCs, annual ERRA proceedings, and other filings to address specific
9 issues such as employee retention and decommissioning costs.³⁶ PG&E recovers DCP
10 costs from bundled and departed load customers in its service territory through PCIA and
11 Nuclear Decommissioning rates.³⁷ SB 846 directed the Commission to authorize PG&E
12 to recover the net cost of DCP extended operations through a new proceeding structured
13 similarly to its annual ERRA Forecast proceeding.³⁸

14 For the period of DCP extended operations, PG&E should present for approval a
15 single application with an annual forecast of all DCP-related costs eligible for recovery
16 from ratepayers (**DCP Forecast Application**). As California Public Utilities Code Section
17 712.8(h)(1) suggests, the DCP Forecast Application should follow a similar process as the
18 ERRA Forecast proceeding, *i.e.*, an initial application presenting PG&E’s forecast of net
19 costs for the subsequent year, followed by a period of party review and opportunities to file
20 testimony. PG&E should also be required to submit an update to forecasted costs, during the
21 pendency of the annual forecast proceeding, to capture the most recent market conditions
22 available prior to establishing the final net cost forecast.³⁹ The Commission should require

³⁶ PG&E Response to CalCCA Data Request 1.01.

³⁷ PG&E Response to CalCCA Data Request 1.02.

³⁸ Cal. Pub. Util. Code § 712.8(h)(1).

³⁹ In PG&E’s annual ERRA Forecast proceedings, PG&E files a “Fall Update” in October providing updated forecasted costs.

1 PG&E to prepare its annual DCPD Forecast Application based on the same forecast
2 assumptions used to develop the ERRA Forecast for the corresponding period (including,
3 for example, forecasted market revenues, fuel costs, generation output, and other variables),
4 and procedural milestones in the DCPD Forecast Application should follow a timeline that
5 runs in parallel with the ERRA Forecast proceeding.

6 Despite the similarity between the two filings, the DCPD Forecast Application
7 should be a standalone application to facilitate participation from all affected
8 stakeholders in the state without complicating PG&E's ERRA Forecast application
9 process. That application is typically limited to a handful of parties seeking to address
10 PG&E-specific issues and rarely includes the other IOUs as parties. Moreover, a
11 substantial amount of work is done in that proceeding, including ratemaking and the
12 implementation of policy directed by other cases. Examples of these issues in just the
13 past few years include:

- 14 • The methodology to refund a CAM misallocation;⁴⁰
- 15 • The methodology to return ERRA overcollections in an equitable manner;⁴¹
- 16 • The methodology to calculate the RA component of Green Tariff Shared
17 Renewable rates;⁴²
- 18 • Implementation of changes to the methodology used to calculate the PCIA from
19 D.18-10-019 and D.19-10-001;⁴³
- 20 • The inclusion of unapproved Catastrophic Event Memorandum Account and
21 Wildfire Expense Memorandum Account costs in the PCIA revenue
22 requirement;⁴⁴ and

⁴⁰ D.20-02-047 at 10.

⁴¹ *Id.* at 11-12.

⁴² D.20-12-038 at 28-29.

⁴³ *See, e.g.*, D.18-10-019 at Ordering Paragraphs (**OPs**) 8 and 10; D.19-10-001 at OPs 2-4.

⁴⁴ A.21-06-001, PG&E Prepared Testimony at 9-8:10-16 to 9-9:1-4 and Table 9-2.

- Addressing the accounting resulting from PG&E acting as a Central Procurement Entity (D.20-06-002), to meet 2021 summer reliability targets (D.21-02-028); or to meet the incremental procurement targets 2021-2023 (D.19-11-016) that impact the CAM balancing account, ModCAM balancing accounts and the Portfolio Allocation Balancing Account.

Creating a standalone proceeding for DCPD-related issues would avoid overwhelming the expedited ERRA Forecast proceeding with parties and issues that seek to only address DCPD-related issues. The significant non-DCPD-related policy and implementation issues are frequently addressed in PG&E's ERRA Forecast proceeding.

PG&E would no longer present DCPD-related costs in its ERRA Forecast or recover those costs through PCIA rates during the period of extended operations. Rather, PG&E would recover the Commission-approved DCPD net cost forecast through distinct NBCs included in the delivery rates for each IOU's service territory.

Each year as part of the DCPD Forecast Application the Commission would approve 1) the total forecasted DCPD net costs, and 2) the amount allocated to customers in each IOU's service territory. Each IOU would then be responsible for calculating the corresponding volumetric NBC charged to customers of all jurisdictional LSEs based on electricity consumption in their own service territory.⁴⁵ The IOUs would include their respective NBCs in delivery rates via each IOU's annual consolidated rate change advice letter process (*e.g.*, the Consolidated Rate Change in Southern California Edison's service territory and the Annual Electric True-UP (AET) in PG&E's service territory).⁴⁶

In sum, the ratemaking process for DCPD costs would be:

⁴⁵ Cal. Pub. Util. Code § 712.8(l)(1).

⁴⁶ See Resolution E-5217 (establishing uniform procedures to standardize the large energy utilities' annual end-of-year consolidated electric revenue for January 1 rate change advice letter filings to provide a more efficient process) Small jurisdictional IOUs subject to the requirements of SB 846 would follow the equivalent process for routine rate updates in their respective service territories (Aug. 4, 2022): <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M496/K459/496459720.PDF>.

- 1 1. PG&E prepares an annual DCPD Forecast Application that is similar to
2 but separate from the ERRA Forecast Application.
- 3 2. A Commission decision in the DCPD Forecast Application sets the level of
4 the revenue requirement to be collected through the DCPD-specific NBC
5 in each IOU's service territory.
- 6 3. That revenue requirement is translated to a \$/kWh charge for eligible
7 customers in an IOU's service territory in November and December via
8 each IOU's consolidated rate change advice letter filing.

9 **B. PG&E's DCPD Forecast Application Should Include Detailed Support of The**
10 **Projected Net Costs to Be Charged Customers**

11 As described earlier, PG&E is entitled to recover from customers the reasonable
12 costs and expenses necessary to operate DCPD beyond the current expiration dates, net of
13 market revenue from DCPD operation. The Commission should require PG&E to present
14 detailed projections of all costs and revenues during DCPD extended operations in the
15 annual DCPD Forecast Application. The presentation of costs and revenue included in the
16 DCPD Forecast Application should be similar to the information provided in PG&E's
17 GRC and ERRA proceedings. For example, PG&E should provide details of DCPD fixed
18 costs by Major Work Category (MWC) and FERC account. Detailed generation output
19 projections, nuclear fuel procurement costs, and other related forecast inputs should
20 support forecasts for variable costs.

21 To incorporate the new SB 846 framework, the traditional DCPD revenue
22 requirement calculation requires several changes. For example, SB 846 allows PG&E to
23 recover all operating expenses and certain tax costs, but it is no longer allowed to record
24 capital expenditures to rate base. Routine capital expenditures are to be recovered as
25 operating expenses, and significant one-time capital expenditures may be amortized over
26 more than one year as authorized by the Commission. Furthermore, several new fees will
27 be charged to customers to compensate PG&E shareholders in lieu of a rate-based return

1 on investments, including a volumetric performance-based fee of \$13.00/MWh for each
2 MWh generated by DCPD and a fixed payment of \$100 million (\$50 million per unit)
3 annually. PG&E is also entitled to charge customers \$12.5 million per month to fund a
4 \$300 million liquidated damages balancing account that can be used to cover the cost of
5 replacement power during certain outages. Figure 4 provides an illustrative revenue
6 requirement compilation, following a format consistent with the GRC and ERRA,
7 demonstrating the calculation of DCPD net costs before and after adopting the changes
8 that must be implemented pursuant to SB 846.

1

Figure 4

(\$000)

Line	Cost Category	Source	Current	SB 846
1	Operating Expenses			
2	Production	2023 GRC; February Update	\$315,173	\$315,173
3	Transmission	2023 GRC; February Update	\$4,283	\$4,283
4	Uncollectibles	2023 GRC; February Update	\$3,765	\$3,765
5	Administrative and General	2023 GRC; February Update	\$241,315	\$241,315
6	Franchise & SFGR Tax Requirement	2023 GRC; February Update	\$9,577	\$9,577
7	Amortization	2023 GRC; February Update	\$31,327	\$31,327
8	Other Adjustments	2023 GRC; February Update	(\$1,142)	(\$1,142)
9	Taxes			
10	Property	2023 GRC; February Update	\$19,669	\$19,669
11	Payroll	2023 GRC; February Update	\$18,735	\$18,735
12	Business	2023 GRC; February Update	\$264	\$264
13	Other	2023 GRC; February Update	\$4,964	\$4,964
14	State Corporation Franchise	2023 GRC; February Update	\$30,786	\$30,786
15	Federal Income Tax	2023 GRC; February Update	\$24,010	NA
16	Other			
17	Depreciation	2023 GRC; February Update	\$409,011	NA
18	Other Revenue	2023 GRC; February Update	(\$4,684)	(\$4,684)
19	Employee Retention and License Renewal Costs	2023 ERRRA/AL 5268-E; 5461-E-A	\$53,192	\$53,192
20	SB 846 Items			
21	Fixed Payment In Lieu of Rate-Based Return	PUC § 712.8(f)(6)		\$100,000
22	Volumetric Payment In Lieu of Rate-Based Return	PUC § 712.8(f)(5)		\$228,035
23	Liquidated Damages Balancing Acct Funding	PUC § 712.8(g), § 712.8(i)		\$150,000
24	Replacement Power Costs	PUC § 712.8(i)		TBD
25	Incremental Decommissioning Planning	PUC § 712.8(f)(1), 712.8(f)(3)		TBD
26	Independent Review Panel Costs	PUC § 712.8(f)(4)		TBD
27	Annual Capital Expenditures	PUC § 712.8(h)(2)		TBD
28	Return on Rate Base			
29	Rate Base	2023 GRC; February Update	\$1,952,370	NA
30	Rate of Return		7.34%	NA
31	Return on Rate Base	2023 GRC; February Update	\$143,304	NA
32	Variable Production Costs			
33	Fuel	2021 FERC Form 1	\$121,881	\$121,881
34	Total Costs		\$1,425,430	\$1,327,140
35	CAISO Market Revenue			
36	2023 NP-15 Market Price (\$/MWh)	2023 ERRRA Energy Index	\$84.22	\$84.22
37	Annual Generation (GWh)	2021 FERC Form 1	17,541	17,541
38	Total Wholesale Market Revenue		\$1,477,318	\$1,477,318
39	Net Costs		(\$51,887)	(\$150,178)

2

3

4

In its May 19, 2023, Prepared Testimony (DCPP Cost Testimony) providing historical and forecast cost information for DCPP, PG&E presented limited cost

1 information according to the Electric Utility Cost Group (EUCG) method which
2 excludes several cost categories that PG&E considers corporate costs but that are
3 assigned or allocated to DCPD for ratemaking purposes.⁴⁷ As operator of the plant, PG&E
4 will continue to incur common corporate costs in support of DCPD extended operations,
5 and these costs are appropriately recovered from customers through the DCPD NBC.
6 PG&E acknowledged in its DCPD Cost Testimony that the annual cost recovery
7 application for extended operations would include all costs relevant to DCPD operations,
8 including common costs such as benefits, overhead, employee retention, regulatory
9 compliance, and statutory charges and fees.⁴⁸ As such, PG&E should present its request
10 for cost recovery in the DCPD Forecast Application in a manner consistent with the GRC
11 and ERRA filings.

12 In addition, the Commission should require PG&E to demonstrate in its DCPD
13 Forecast Application that its DCPD Forecast includes common cost assumptions that are
14 consistent with its 2023 GRC. This GRC includes attrition years that extend beyond the
15 original DCPD expiration dates to 2026 and assumes DCPD is retired.⁴⁹ For example, to
16 determine the DCPD revenue requirement in its GRC PG&E allocates several categories
17 of common corporate costs (*e.g.*, administrative and general expense) to DCPD using
18 approved allocation factors. When asked in discovery, PG&E objected to providing
19 details of the common costs allocated to DCPD in the 2023 GRC and opted not to explain
20 whether actual common costs would be impacted by extended operations.⁵⁰ Because
21 PG&E would not provide these additional details, Figure 4 contains only an illustrative

⁴⁷ PG&E Prepared Testimony (May 19, 2023) at 2:3-18.

⁴⁸ *Id.* at 16:1-13.

⁴⁹ PG&E Response to CalCCA Data Request 1.04.

⁵⁰ PG&E Responses to CalCCA Data Requests 1.05- 1.08.

1 revenue requirement using summarized cost categories from PG&E’s GRC for the 2023
2 test period. In its DCPD Forecast Application, the Commission should require PG&E to
3 quantify the impact of DCPD extended operations on its common costs relative to the
4 amount approved in its 2023 GRC and demonstrate that there is no double counting of
5 common costs proposed for recovery in the GRC and DCPD NBC.

6 Lastly, SB 846 states: “To the extent the commission decides to allocate any
7 benefits or attributes from extended operations of the Diablo Canyon powerplant, the
8 commission may consider the higher cost to customers in the operator’s service area.”⁵¹
9 As a trade association with members that are both within and outside of “the operator’s
10 service area,” CalCCA has a deep interest in finding the fairest way for the Commission
11 to act upon such considerations.

12 Under SB 846, PG&E will assign a small portion of the costs authorized for
13 recovery directly to customers of LSEs in its service territory. Those customers are also
14 the sole beneficiaries of surplus wholesale market revenue and the return of excess funds
15 paid into the liquidated damages balancing account by all customers. For example, half of
16 the volumetric payment in lieu of a rate-based return (\$6.50, in 2022 dollars, for each
17 megawatt hour generated by DCPD during the period of extended operations)⁵² is to be
18 paid only by the customers of LSEs in PG&E service territory. In exchange for this cost
19 responsibility, customers of LSEs in PG&E service territory will receive a credit for all
20 surplus wholesale market revenue remaining after offsetting DCPD’s annual operating
21 costs.

⁵¹ Cal. Pub. Util. Code § 712.8(q).

⁵² Cal. Pub. Util. Code § 712.8(f)(5).

1 Figure 5 is an illustrative division of net annual costs and revenue recovered from
2 all customers versus those charged only to customers of LSEs in PG&E service territory.
3 Notably, at current wholesale market prices it is possible that the total DCPD costs will be
4 less than the total market revenue. In that case, PG&E will return the surplus revenue only
5 to customers of LSEs in its service territory. Furthermore, even though customers of all
6 LSEs in California will fund the liquidated damages balancing account (\$12.5 million per
7 month, up to a total balance of \$300 million), funds remaining in the balancing account at
8 the end of DCPD extended operations will be returned solely to customers of LSEs in
9 PG&E service territory.⁵³

⁵³ Cal. Pub. Util. Code §§ 712.8(g), 712.8(i), 712.8(u).

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Figure 5

Line	Cost Category	Costs	Market Revenue	Net Costs
1	Operating Expenses	\$604,298		
2	Taxes	\$74,418		
3	Other	\$48,508		
4	SB 846 Items			
5	Fixed Payment In Lieu of Rate-Based Return	\$100,000		
6	Volumetric Payment In Lieu of Rate-Based Return	\$114,018		
7	Liquidated Damages Balancing Acct Funding	\$150,000		
8	Replacement Power Costs	TBD		
9	Incremental Decommissioning Planning	TBD		
10	Independent Review Panel Costs	TBD		
11	Annual Capital Expenditures	TBD		
12	Variable Production Costs	\$121,881		
13	Recovered From All Customers	\$1,213,123	(\$1,213,123)	\$0
14	SB 846 Items			
15	Volumetric Payment In Lieu of Rate-Based Return	\$114,018		
16	Recovered From PG&E Service Territory Customers	\$114,018	(\$264,195)	(\$150,178)
17	Grand Total	\$1,327,140	(\$1,477,318)	(\$150,178)
18	CAISO Market Revenue			
19	2023 NP-15 Energy Index (\$/MWh)	\$84.22		
20	Annual Generation (GWh)	17,541		
21	Total Wholesale Market Revenue	\$1,477,318		

2

3 **IV. THE NET COSTS OF DCPD EXTENDED OPERATIONS SHOULD BE TRACKED**
4 **IN A NEW BALANCING ACCOUNT AND RECOVERED THROUGH A NEW**
5 **NBC INCLUDED IN IOU DELIVERY RATES**

6 As described earlier, PG&E currently recovers its costs to operate DCPD, both
7 direct and indirect, through PCIA rates. To properly track and recover the net costs of
8 DCPD extended operations, all related costs items should no longer be included in the
9 PCIA but should be recorded in a new balancing account established specifically for this
10 purpose.⁵⁴ PG&E has been developing parameters for the new balancing account, and

⁵⁴ Notably, in its 2024 ERRA Forecast application filed May 15, 2023, PG&E removed DCPD Unit 1 from the PCIA revenue requirement effective November 2024.

1 required subaccounts, to enable tracking and allocation of costs to appropriate LSEs;
2 CalCCA largely supports PG&E’s approach on this matter.

3 **A. PG&E Has Already Developed A New Balancing Account to Record The Net**
4 **Costs of DCPD Extended Operations**

5 PG&E proposed the Diablo Canyon Extended Operations Balancing Account
6 (DCEOBA) in Advice Letter (AL) 6870-E to track the costs during DCPD extended
7 operations. CalCCA reviewed PG&E’s proposed tariff statements as part of the AL 6870-
8 E process, and PG&E incorporated CalCCA’s feedback into the tariff language. CalCCA
9 supports using the DCEOBA to track DCPD extended operations cost recovery as long as
10 the tariff language accommodates recording all common costs that may be allocated to
11 DCPD. CalCCA agrees with PG&E’s proposal to allocate cost responsibility by IOU
12 service territory in separate subaccounts of the DCEOBA.

13 **B. A New NBC Should Be Created and Charged to Customers in Jurisdictional**
14 **IOUs’ Delivery Rates**

15 California Public Utilities Code Section 712.8(I)(1) specifies, “The recovery of
16 these non-bypassable costs by the [LSEs] shall be based on each customer’s gross
17 consumption of electricity regardless of a customer’s net metering status or purchase of
18 electric energy and service from an [ESP], [CCA], or other third-party source of electric
19 energy or electricity service.” As such, each IOU will need to implement its own NBC
20 and remit to PG&E the revenue received through the charge.

21 As described earlier in my testimony, one outcome of PG&E’s DCPD Annual
22 Forecast will be an allocation of the net costs of DCPD extended operations for the
23 upcoming year by IOU service territory. To develop the DCPD NBC, each IOU would
24 first need to allocate its share of DCPD costs among its unique customer classes. The net
25 costs by customer class would then be divided by the forecast class energy consumption

1 to develop a \$/kWh rate. Similar to the allocation across service territories, DCPD costs
2 should be allocated among customer classes using each customer class's contribution to
3 12-month coincident peak. This is also the approach currently used to develop CAM
4 surcharges. On an annual basis, each IOU should submit its DCPD NBC proposal for
5 Commission approval and implementation in rates through the annual consolidated rate
6 change advice letter process.

7 This concludes my testimony.

ATTACHMENT A
CURRICULUM VITAE OF BRIAN DICKMAN

Mr. Brian Dickman is a partner in NewGen's energy practice with 20 years of utility industry experience. Mr. Dickman's career includes over a decade working for PacifiCorp, a vertically integrated investor-owned utility, including senior-level positions in regulatory, financial, and commercial roles. He began consulting in 2017, assisting a wide array of clients across the United States and internationally, including utilities, large consumers, and private investment firms. Mr. Dickman has extensive experience preparing and evaluating utility revenue requirements and cost allocation studies, developing utility avoided costs, and analyzing the impact of new initiatives and transactions on a utility and its customers. In addition to his extensive technical experience, Mr. Dickman understands the regulatory governance process, and he has personally testified as an expert witness before state public utility commissions in California, Idaho, Indiana, Oregon, Utah, Washington, and Wyoming.

Mr. Dickman advises numerous Community Choice Aggregator (CCA) clients in California, focusing on regulatory and rate issues such as the state-mandated exit fee known as the Power Charge Indifference Adjustment (PCIA). He also represents California CCAs as a member of the Cost Allocation Mechanism Procurement Review Groups for PG&E and Southern California Edison established by the California Public Utility Commission to provide an independent review of the centralized procurement of local generation capacity requirements.

EDUCATION

- Master of Business Administration, Finance Emphasis, University of Utah
- Bachelor of Science, Accounting, Utah State University

KEY EXPERTISE

- Cost of Service and Rates
- Financial Analysis and Modeling
- Power Charge Indifference Amount
- Regulatory Strategy
- Revenue Requirement

RELEVANT EXPERIENCE

Electric Cost of Service, Rate Design, and Regulatory Analysis

Mr. Dickman leads projects developing utility revenue requirements, preparing cost of service and rate design studies, and performing financial and regulatory analyses for electric utilities. Mr. Dickman previously held leadership positions at a multi-billion-dollar utility. He was responsible for interfacing with state regulatory agencies in support of revenue requirements, cost recovery mechanisms, avoided costs, valuations of potential asset acquisitions and other commercial opportunities, and financial impacts of utility initiatives. Mr. Dickman now works with clients and stakeholders to prepare pro forma financial models to determine revenue sufficiency, evaluate the cost of service studies and rate design proposals, and support such proposals before local and state governing bodies. Mr. Dickman's experience also includes evaluating the financial and rate impact of proposed mergers and acquisitions, acquisition and divestiture of utility assets, negotiated retail service contracts, changing business models, and stranded costs due to exiting load.

Brian Dickman

PARTNER

Expert Witness and Litigation Support

Mr. Dickman provides comprehensive expert witness testimony related to utility revenue requirements, cost of service, rate design, and other ratemaking issues before state and local regulatory bodies. He has provided litigation support in wholesale and retail jurisdictions, including California, Idaho, Indiana, Oregon, Washington, Wyoming, Utah, the Federal Energy Regulatory Commission, and Ontario Energy Board. Mr. Dickman offers expert witness testimony and litigation support in the following areas.

Revenue Requirement | Cost Allocation | Rate Design

Mr. Dickman prepared revenue requirements, inter-jurisdictional cost allocation, coincident peak allocation studies, and supporting testimony for PacifiCorp over many years. He now provides litigation support and expert testimony for clients wishing to review utility filings on revenue requirement, cost allocation, and rate design, including program-specific rate tariffs.

Power Supply Costs | Stranded Costs | Rate Adjustment Mechanisms

Mr. Dickman has prepared and evaluated variable power supply cost forecasts, power supply cost balancing accounts and other rate mechanisms, stranded costs, and exit fees for departing load. Since 2019, Mr. Dickman has actively participated in PCIA matters in California on behalf of CCA clients.

Avoided Costs | Resource Valuation

Mr. Dickman provided expert testimony for PacifiCorp on various components included in a proposed method for valuing solar generation resources, the calculation of Public Utility Regulatory Policies Act avoided costs for large resources, and support of modifications to the avoided cost calculation for small resources.

A sample of Mr. Dickman's utility clients includes the following:

- Abu Dhabi Distribution Company, UAE
- Central Coast Community Energy, CA
- City and County of San Francisco, CA
- Clean Power Alliance, CA
- Duke Energy, NC
- East Bay Community Energy, CA
- Hydro One, Ontario, CA
- Liberty Utilities, CA
- Lubbock Power and Light, TX
- Minnesota Power, MN
- New York Power Authority, NY
- Portland General Electric, OR
- San Diego Community Power, CA
- San Jose Clean Energy, CA
- Silicon Valley Clean Energy Authority, CA
- Vermont Gas Systems, VT

A sample of Mr. Dickman's non-utility clients includes the following:

- Blackstone Group, NY
- California Community Choice Association, CA
- Facebook, CA
- Hemlock Semiconductor, MI
- Newmont Mining, NV
- SABIC Innovative Plastics, IN
- Tri-County Metropolitan Transportation District, OR
- Vistra Energy, TX

WORKSHOPS AND PRESENTATIONS

Host organizations and the topics Mr. Dickman presented are displayed below.

Customer Choice at a Vertically Integrated Utility

Advanced Workshop in Regulation and Competition, Center for Research in Regulated Industries, 2018

Record of Testimony: Brian Dickman

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
1. SCE	A.12-01-008 A.12-04-020 A.14-01-007	Declaration supporting response to petition for modification of D.15-01-051, addressing changes to optional green tariff program rates	California Public Utilities Commission	Clean Power Alliance, California Choice Energy Authority	2022
2. SCE	A.22-05-014	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	Clean Power Alliance, California Choice Energy Authority, and Central Coast Community Energy	2022
3. PG&E, SCE, SDG&E	A.20-02-009 A.20-04-002 A.20-06-001 (Consolidated)	Expert testimony evaluating the unrealized sales volumes and revenue due to Public Safety Power Shutoff events	California Public Utilities Commission	CCA Parties (9 individual CCAs)	2022
4. San Diego Gas & Electric	A.21-09-001	Expert testimony responding to proposed residential electrification tariff	California Public Utilities Commission	San Diego Community Power and Clean Energy Alliance	2022
5. San Diego Gas & Electric	R.20-05-003	Declaration supporting motion for clarification of D.19-11-016, quantifying impact to allocated incremental reliability procurement requirement due to departing load	California Public Utilities Commission	San Diego Community Power	2021
6. Southern California Edison	A.21-06-003	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	Clean Power Alliance and California Choice Energy Authority	2021
7. Pacific Gas & Electric	A.21-06-001	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	Joint Community Choice Aggregators	2021
8. San Diego Gas & Electric	A.21-04-010	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	San Diego Community Power and Clean Energy Alliance	2021
9. Pacific Gas & Electric	A.12-01-008 A.12-04-020 A.14-01-007	Declaration supporting petition for modification of D.15-01-051, recommending changes to optional green tariff program rates designed to avoid shifting costs of resource capacity to non-participants	California Public Utilities Commission	Joint Community Choice Aggregators	2021

Record of Testimony: Brian Dickman

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
10. Pacific Gas & Electric	A.19-11-019	Expert testimony (adopted) addressing use of marginal costs to determine economic development rates and responding to proposed electrification tariff for retail customers	California Public Utilities Commission	Joint Community Choice Aggregators	2021
11. Pacific Gas & Electric	A.20-07-002	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	Joint Community Choice Aggregators	2020
12. Southern California Edison	A.20-07-004	Expert testimony evaluating the calculation of the Power Charge Indifference Amount charged to Community Choice Aggregators	California Public Utilities Commission	Clean Power Alliance and California Choice Energy Authority	2020
13. Pacific Power	Docket UE 375	Joint testimony supporting a settlement agreement resolving the annual variable power supply cost forecast and generation resource dispatch model	Public Utility Commission of Oregon	Facebook, Inc.	2020
14. Pacific Gas & Electric	A.20-02-009	Expert testimony evaluating the appropriateness of entries recorded to the Portfolio Allocation Balancing Account to true up the Power Charge Indifference Amount	California Public Utilities Commission	Joint Community Choice Aggregators	2020
15. Vectren Energy Delivery of Indiana	Cause No. 43354 MCRA 21 S1	Expert testimony supporting a settlement agreement regarding the calculation and use of a 4CP load study to allocate tariff rider costs among customer classes	Indiana Utility Regulatory Commission	SABIC Innovative Plastics Mt. Vernon, LLC	2020
16. PacifiCorp	Docket UE 307	Expert testimony supporting the annual variable power supply cost forecast and generation resource dispatch model	Public Utility Commission of Oregon		2016
17. PacifiCorp	Docket UM 1662	Joint testimony with Portland General Electric regarding the need for a renewable resource tracking mechanism to provide cost recovery related to the impacts of renewable resource generation	Public Utility Commission of Oregon		2015
18. PacifiCorp	Docket UE 296	Expert testimony supporting the annual variable power supply cost forecast and generation resource dispatch model	Public Utility Commission of Oregon		2015

Record of Testimony: Brian Dickman

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
19. PacifiCorp	Docket No. 20000-469-ER-15	Expert testimony regarding the annual variable power supply cost forecast and modifications to the Energy Cost Adjustment Mechanism	Public Service Commission of Wyoming		2015
20. PacifiCorp	Docket No. 15-035-03	Provided expert testimony regarding the true up of variable power supply costs in the Energy Balancing Account mechanism	Public Service Commission of Utah		2015
21. PacifiCorp	Docket UM 1716	Expert testimony proposing changes to the calculation of PURPA avoided costs for large resources	Public Utility Commission of Oregon		2015
22. PacifiCorp	Docket No. 20000-481-EA-15	Expert testimony proposing changes to the calculation of PURPA avoided costs for large resources	Public Service Commission of Wyoming		2015
23. PacifiCorp	Docket No. 15-035-T06	Expert testimony updating standard PURPA avoided cost prices and supporting modifications to the avoided cost calculation for small resources	Public Service Commission of Utah		2015
24. PacifiCorp	Case No. PAC-E-15-03	Expert testimony proposing changes to the calculation of PURPA avoided costs for large resource	Idaho Public Utilities Commission		2015
25. PacifiCorp	Docket UE-144160	Declaration supporting updates to standard PURPA avoided cost prices and supporting modifications to the avoided cost calculation for small resources	Washington Utilities and Transportation Commission		2014
26. PacifiCorp	Docket UE 287	Expert testimony supporting the annual variable power supply cost forecast and generation resource dispatch model	Public Utility Commission of Oregon		2014
27. PacifiCorp	Case No. PAC-E-14-01	Expert testimony regarding the true up of variable power supply costs in the Energy Cost Adjustment Mechanism	Idaho Public Utilities Commission		2014
28. PacifiCorp	Docket A.14-08-002	Expert testimony supporting the annual variable power supply cost forecast and the true up of costs in the Energy Cost Adjustment Clause mechanism	California Public Utilities Commission		2014
29. PacifiCorp	Docket No. 20000-447-EA-14	Expert testimony regarding the true up of annual variable power supply cost in the Energy Cost Adjustment Mechanism	Public Service Commission of Wyoming		2014

Record of Testimony: Brian Dickman

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
30. PacifiCorp	Docket No. 14-035-31	Expert testimony regarding the true up of variable power supply costs in the Energy Balancing Account mechanism	Public Service Commission of Utah		2014
31. PacifiCorp	Case No. PAC-E-13-03	Expert testimony regarding the true up of variable power supply costs in the Energy Cost Adjustment Mechanism	Idaho Public Utilities Commission		2013
32. PacifiCorp	Docket A.13-08-001	Expert testimony supporting the annual variable power supply cost forecast and the true up of costs in the Energy Cost Adjustment Clause mechanism	California Public Utilities Commission		2013
33. PacifiCorp	Docket No. 13-035-32	Expert testimony regarding the true up of variable power supply costs in the Energy Balancing Account mechanism	Public Service Commission of Utah		2013
34. PacifiCorp	Docket UM 1610	Expert testimony proposing changes to the calculation of PURPA avoided costs for large and small generation resources	Public Utility Commission of Oregon		2012
35. PacifiCorp	Docket A.12-08-003	Expert testimony supporting the annual variable power supply cost forecast and the true up of costs in the Energy Cost Adjustment Clause mechanism	California Public Utilities Commission		2012
36. PacifiCorp	Docket No. 12-035-67	Expert testimony regarding the true up of variable power supply costs in the Energy Balancing Account mechanism	Public Service Commission of Utah		2012
37. PacifiCorp	Docket No. 20000-389-EP-11	Expert testimony regarding the collection of deferred balances accrued through previous Power Cost Adjustment Mechanisms	Public Service Commission of Wyoming		2011
38. PacifiCorp	Docket No. 20000-405-ER-11	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Wyoming		2011
39. PacifiCorp	Case No. GNR-E-11-03	Expert testimony proposing changes to the calculation of PURPA avoided costs for large and small generation resources	Idaho Public Utilities Commission		2011
40. PacifiCorp	Case No. PAC-E-06-10	Expert testimony regarding low income customer weatherization rebates	Idaho Public Utilities Commission		2010

Record of Testimony: Brian Dickman

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
41. PacifiCorp	Docket No. 20000-405-ER-10	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Wyoming		2010
42. PacifiCorp	Docket No. 10-035-89	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Utah		2010
43. PacifiCorp	Docket No. 20000-352-ER-09	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Wyoming		2009
44. PacifiCorp	Case No. PAC-E-08-07	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Idaho Public Utilities Commission		2008
45. PacifiCorp	Docket No. 20000-333-ER-08	Inter-jurisdictional cost allocation and revenue requirement and sponsored expert testimony in corresponding general rate case	Public Service Commission of Wyoming		2008

ATTACHMENT B
SELECT DATA RESPONSES

PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Power Plant Operations Extension OIR
Rulemaking 23-01-007
Data Response

PG&E Data Request No.:	CalCCA_001-Q001		
PG&E File Name:	DiabloCanyonPowerPlantOperationsExtensionOIR_DR_CalCCA_001-Q001		
Request Date:	May 5, 2023	Requester DR No.:	001
Date Sent:	May 19, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:	Ryan Stanley / Tom Baldwin	Requester:	Nikhil Vijaykar

QUESTION 001

Please identify all accounting mechanisms (including balancing accounts, memorandum accounts, etc.) PG&E relies on to record costs related to Diablo Canyon operation, maintenance, licensing, and decommissioning and retirement.

ANSWER 001

PG&E currently relies on the following active accounting mechanisms to record costs and cost recovery related to Diablo Canyon Power Plant’s (DCPP) operations as follows:

Portfolio Allocation Balancing Account (PABA)

The purpose of this balancing account is to recover all “above-market” costs from all generation resources eligible for recovery through Power Charge Indifference Adjustment (PCIA) rates. This includes several different operational activities as found in PG&E’s Electric Preliminary Statement Part HS and described further below:¹

Utility-Owned Generation Revenue Requirements

PABA recovers the base revenue requirements associated with DCPP’s operations, maintenance, and capital recovery as identified in PG&E’s general rate case (as one of several utility-owned generation facilities). PABA also recovers specific revenue requirements related to the DCPP Retention Program and DCPP license renewal costs associated with relicensing costs for the current operating license period (i.e., prior to SB 846). Please see Electric Preliminary Statement Part HS, Tariff Lines 5.n., 5.p through 5.r. for relevant entries related to Utility-Owned Generation revenue requirements.

¹ Hyperlink at: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_HS.pdf.

CAISO-Related Entries

PABA also records relevant CAISO activity. This includes energy market revenues from scheduling and/or bidding DCPD into the CAISO market net of any miscellaneous or site-specific load that is also incurred for DCPD. Please see Electric Preliminary Statement Part HS, Tariff Lines 5.t. through 5.v. for relevant CAISO-related entries.

Fuel Costs

In addition, PABA is authorized to recover nuclear fuel expenses and miscellaneous expenses for DCPD, as well as carrying costs on PG&E's net outstanding nuclear fuel inventory at the rate of the three-month commercial paper rate. Please see Electric Preliminary Statement Part HS, Tariff Lines 5.z. and 5.aa. for relevant nuclear fuel entries.

Note: Recovery within PABA is included through the current licensing period and will not include extension period activity.

Nuclear Decommissioning Adjustment Mechanism (NDAM)

This account recovers authorized nuclear decommissioning revenue requirements and to provide full recovery of costs. In addition, the approved tariff includes recovery of other related expenses including costs to satisfy the requirements of CA Bill 968 and Public Utilities Code Section 712.5 Section 3, DCPD Employee Retraining Program budget, and authorized recovery of funds approved in the Community Impact Mitigation Program (CIMP). Detailed accounting entries can be found in PG&E's Electric Preliminary Statement Part DB.²

Diablo Canyon Retirement Balancing Account (DCRBA)

This account is used to track actual expenses and capital revenue requirements against expense budgets or capital revenue requirements related to (1) DCPD full book value by the time Units 1 & 2 cease operations, (2) the DCPD Employee Retention Program, and (3) the DCPD Employee Retraining Program. The differences are transferred to PABA or NDAM as applicable and as authorized by the Commission. Detailed entries can be found in PG&E's Electric Preliminary Statement Part HK.³

Nuclear Regulatory Commission Rulemaking Balancing Account (NRCRBA)

This account is used for recovery of actual expenses for complying with existing, emerging or evolving NRC regulations and directives. These costs include but are not limited to, the following four major NRC rulemaking processes currently in progress: Fukushima Daiichi Rulemaking, Cyber-Security Rulemaking, Emergency Planning

² Hyperlink at: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_DB.pdf.

³ Hyperlink at: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_HK.pdf.

Rulemaking, and the new National Fire Protection Standard (NFPA) 805 Rulemaking. Detailed entries can be found in PG&E's Electric Preliminary Statement Part GM.⁴

Department of Energy Litigation Balancing Account (DOELBA)

This account tracks and records for customers of any proceeds, net of costs, from PG&E's lawsuit against the Department of Energy (DOE) filed in the Federal Court of Claims on January 22, 2004, regarding the DOE's breach of spent fuel contracts and any additional claims for reimbursement that PG&E may have against DOE arising out of or related to spent fuel contracts. This account ensures the proper crediting and allocation of proceeds and costs for the benefit of customers as determined by the Commission between the Diablo Canyon and Humboldt Bay nuclear power plants. The DOELBA will expire after litigation is completed, proceeds have been received, and the Commission has authorized disposition of the balance. Amounts get transferred to PABA or NDAM as authorized by the Commission. Detailed entries can be found in PG&E's Electric Preliminary Statement Part DZ.⁵

Additional mechanisms related to costs for extend operations of DCCP in accordance with SB 846 were proposed as part of PG&E's Advice Letter 6870-E and Supplemental Advice Letter 6870-E-A, currently pending disposition from the Commission.

⁴ Hyperlink at: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_GM.pdf

⁵ Hyperlink at: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_DZ.pdf

**PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Power Plant Operations Extension OIR
Rulemaking 23-01-007
Data Response**

PG&E Data Request No.:	CalCCA_001-Q002		
PG&E File Name:	DiabloCanyonPowerPlantOperationsExtensionOIR_DR_CalCCA_001-Q002		
Request Date:	May 5, 2023	Requester DR No.:	001
Date Sent:	May 19, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:	Ryan Stanley	Requester:	Nikhil Vijaykar

QUESTION 002

Please identify all rate mechanisms currently relied on by PG&E to recover any costs related to Diablo Canyon and describe the costs included in each mechanism.

ANSWER 002

PG&E currently recovers costs associated with Diablo Canyon through two nonbypassable charges:

- Power Charge Indifferent Adjustment (PCIA) rates
- Nuclear Decommissioning rates

PCIA revenues are credited to the Portfolio Allocation Balancing Account (PABA). Nuclear Decommissioning revenues are credited to the Nuclear Decommissioning Adjustment Mechanism (NDAM). Please see PG&E's response to Question 1 of this data request for further details on the activities recovered within PABA and NDAM, as well as other accounts transferred to PABA and NDAM for cost recovery.

**PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Power Plant Operations Extension OIR
Rulemaking 23-01-007
Data Response**

PG&E Data Request No.:	CalCCA_001-Q004		
PG&E File Name:	DiabloCanyonPowerPlantOperationsExtensionOIR_DR_CalCCA_001-Q004		
Request Date:	May 5, 2023	Requester DR No.:	001
Date Sent:	May 19, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:	Brian Ketelsen	Requester:	Nikhil Vijaykar

QUESTION 004

Please confirm that PG&E's 2023 GRC assumes the Diablo Canyon Power Plant is retired in 2024 (Unit 1) and 2025 (Unit 2). If not confirmed, please explain.

ANSWER 004

PG&E objects to this data request as irrelevant and outside the scope of this proceeding. Subject to and without waiving that objection, PG&E confirms that PG&E's 2023 GRC assumes DCPD is retired in 2024 (Unit 1) and 2025 (Unit 2).

**PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Power Plant Operations Extension OIR
Rulemaking 23-01-007
Data Response**

PG&E Data Request No.:	CalCCA_001-Q005		
PG&E File Name:	DiabloCanyonPowerPlantOperationsExtensionOIR_DR_CalCCA_001-Q005		
Request Date:	May 5, 2023	Requester DR No.:	001
Date Sent:	May 19, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:		Requester:	Nikhil Vijaykar

QUESTION 005

Please quantify all common costs by category allocated to Diablo Canyon Power Plant revenue requirement in 2023, 2024, 2025, and 2026 as included in PG&E's February Update of its 2023 GRC. For each category, explain the basis for the total common costs and the method used to allocate costs to Diablo Canyon Power Plant.

ANSWER 005

PG&E objects to this data request on grounds that it is irrelevant and outside the scope of this proceeding.

**PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Power Plant Operations Extension OIR
Rulemaking 23-01-007
Data Response**

PG&E Data Request No.:	CalCCA_001-Q006		
PG&E File Name:	DiabloCanyonPowerPlantOperationsExtensionOIR_DR_CalCCA_001-Q006		
Request Date:	May 5, 2023	Requester DR No.:	001
Date Sent:	May 19, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:		Requester:	Nikhil Vijaykar

QUESTION 006

Please explain whether the common costs identified in the previous request allocated to Diablo Canyon Power Plant prior to its retirement are assumed to be reallocated among other resources and/or departments after Diablo Canyon Power Plant retirement.

ANSWER 006

PG&E objects to this data request on grounds that it is irrelevant and outside the scope of this proceeding.

**PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Power Plant Operations Extension OIR
Rulemaking 23-01-007
Data Response**

PG&E Data Request No.:	CalCCA_001-Q007		
PG&E File Name:	DiabloCanyonPowerPlantOperationsExtensionOIR_DR_CalCCA_001-Q007		
Request Date:	May 5, 2023	Requester DR No.:	001
Date Sent:	May 19, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:		Requester:	Nikhil Vijaykar

QUESTION 007

Please explain whether PG&E assumed a reduction in overall common costs through 2026 due to Diablo Canyon Power Plant retirement. If yes, please quantify the reduction by year and by category. If no, please explain why not.

ANSWER 007

PG&E objects to this data request as irrelevant and outside the scope of this proceeding.

**PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Power Plant Operations Extension OIR
Rulemaking 23-01-007
Data Response**

PG&E Data Request No.:	CalCCA_001-Q008		
PG&E File Name:	DiabloCanyonPowerPlantOperationsExtensionOIR_DR_CalCCA_001-Q008		
Request Date:	May 5, 2023	Requester DR No.:	001
Date Sent:	May 19, 2023	Requesting Party:	California Community Choice Association
PG&E Witness:		Requester:	Nikhil Vijaykar

QUESTION 008

Please explain whether continued operation of Diablo Canyon Power Plant will cause PG&E common costs to be higher than projected in 2025 and 2026 relative to the amount assumed in PG&E’s GRC. If yes, please quantify the incremental common costs by year and category. If not, please explain.

ANSWER 008

PG&E objects to this data request on grounds that PG&E’s GRC costs are irrelevant and outside the scope of this proceeding.

Notwithstanding this objection, PG&E’s May 19, 2023, Testimony in Rulemaking (R.) 23-01-007, Table 2, presents cost forecasts through 2030 that include accounting categories adopted by the Electric Utility Cost Group (EUCG). The “Support Services” line item includes costs for organizations outside of DCPD such as Information Technology, Insurance, Legal, Finance, Executive Leadership, Communications, Safety and Health, Procurement, and Human Resources.

These organizations have separate GRC chapters and are not included in the Nuclear chapter in PG&E’s most recent GRC Application, Application 21-06-021 and therefore could be considered common costs supporting Diablo Canyon.

Of note, the EUCG cost presentation in PG&E’s May 19, 2023, Testimony does not capture items such as property taxes, depreciation, interest expense, and revenues.