

Docket No.: A.25-05-009

Exhibit No.: CALCCA Ex-4

Date: May 5, 2026

Sponsor/Witness: PG&E (Various)

**CALCCA EX-4**  
**PG&E Responses to CalCCA DR Set 18**

**PACIFIC GAS AND ELECTRIC COMPANY  
2027 General Rate Case Phase I  
Application 25-05-009  
Data Response**

<b>PG&amp;E Data Request No.:</b>	CalCCA_018-Q001
<b>PG&amp;E File Name:</b>	GRC-2027-PhI_DR_CalCCA_018-Q001
<b>Request Date:</b>	April 7, 2026
<b>Requester DR No.:</b>	018
<b>Requesting Party:</b>	California Community Choice Association
<b>Requester:</b>	Julia Kantor
<b>Date Sent:</b>	April 21, 2026
<b>PG&amp;E Witness(es):</b>	Kevin Chang, Ned Allis – Finance

**QUESTION 001**

Refer to Exh. PG&E-22 at 9-29:4-16, where PG&E states that “[i]t would be possible [to maintain accumulated depreciation by hydro facility]” but doing so “would require time, resources, cost and effort”: please estimate and/or quantify, to the extent possible:

- a. The time, on an annual basis, associated with maintaining accumulated depreciation by hydro facility.
- b. The annual costs associated with maintaining accumulated depreciation by hydro facility.
- c. Refer also to Exh. PG&E-22 at 9-29:22-25: in PG&E’s view, what would constitute “adequate time” to implement this change? What would be the appropriate way, in PG&E’s view, to track and recover the associated costs?

**ANSWER 001**

PG&E has not performed a full analysis of the scope and requirements for maintaining accumulated depreciation at the hydro facility level and, as a result, this response is based on high level estimates. Actual effort, timelines and cost provided in this response could vary from these estimates which would include both one-time implementation effort plus ongoing annual reviews.

PG&E believes the incremental cost and complexity of this change outweigh any limited incremental benefit. Prior to implementing any change, benefits for the change should be clearly articulated, and all parties should evaluate whether the costs outweighs the benefit of such changes. PG&E contends that maintaining accumulated depreciation at the hydro facility level would not materially improve ratemaking accuracy, revenue requirement outcomes, or customer transparency relative to PG&E’s current practices, which already meet regulatory requirements at FERC account level.

- a. At the outset, there would be up front effort from Gannett Fleming, PG&E and its fixed asset software vendor to implement this change. Gannett Fleming estimates it would take three to four months to perform the analysis and calculations needed for this task. For PG&E to implement Gannett Fleming’s estimates/analysis into its

accounting and tax system, this could take at least 9 months and up to one year. This effort would include engaging with its fixed asset software vendor to evaluate whether (i) solution is available; (ii) designing the solution, if applicable (iii) testing the solution, and (iv) reviewing the results. If additional data changes are needed to implement a software solution, the one-time implementation timeline has historically not been less than 9 months. PG&E also needs to consider whether this accounting change would have a tax accounting impact and perform similar changes to its procedures on the tax accounting side. Accounting and tax changes will need to be reviewed by the Hydro, Accounting and Tax teams.

On an ongoing annual basis, maintaining accumulated depreciation at the hydro facility level would require incremental effort beyond PG&E's current accounting and tax processes. This effort would include at a minimum 240 additional hours annually to perform:

- Ongoing validation and reconciliation of facility-level accumulated depreciation balances within the fixed asset system;
  - Additional review and documentation to support internal control requirements and audit readiness;
  - Incremental coordination between Hydro, Accounting, and Tax functions to ensure consistency of facility-level depreciation treatment; and
  - Increased effort during depreciation study cycles to calculate, review, and validate facility-specific depreciation rates and accumulated depreciation balances.
- b. At the outset, there would be up front effort from Gannett Fleming, PG&E and, potentially, its fixed asset software vendor to implement this change. Gannett Fleming estimates a one-time cost of approximately \$50,000 to perform the analysis and calculations needed for this task. PG&E has not approached its software vendor to estimate the necessary software customization costs but this is generally not less than \$200,000. To ensure the necessary accounting and tax changes, PG&E estimates that it would need at least 2 additional headcounts for approximately 12 months to be on the project.

Annual costs would primarily consist of incremental internal labor costs associated with Accounting and Tax personnel needed to support the activities described in the response to subpart a. These costs would recur annually and increase during depreciation study years.

- c. In PG&E's view, "adequate time" required to implement this change – in addition to the timelines provided in response to subpart a – includes sufficient lead time to address not only system implementation, but also process redesign, internal control updates, staff training, and audit and tax alignment. Based on PG&E's experience with prior accounting system and process changes, as described in subpart (a), PG&E estimates that total implementation would require at least 12 to 15 months, even after completion of the necessary analytical work.

If directed to make such change, PG&E would propose that the most appropriate timing for change would be prior to the next GRC. PG&E would track the one-time implementation costs (for external and internal costs) and would propose to recover these costs within its next GRC.

**PACIFIC GAS AND ELECTRIC COMPANY  
2027 General Rate Case Phase I  
Application 25-05-009  
Data Response**

<b>PG&amp;E Data Request No.:</b>	CalCCA_018-Q002
<b>PG&amp;E File Name:</b>	GRC-2027-PhI_DR_CalCCA_018-Q002
<b>Request Date:</b>	April 7, 2026
<b>Requester DR No.:</b>	018
<b>Requesting Party:</b>	California Community Choice Association
<b>Requester:</b>	Julia Kantor
<b>Date Sent:</b>	April 21, 2026
<b>PG&amp;E Witness(es):</b>	Amara Hayashida – Finance

**QUESTION 002**

Refer to Exh. PG&E-22 at 10-1:25-27, where PG&E states it will “reflect the removal of the DCPD DTA from the revenue requirement calculation in a future Results of Operation (RO) Model update in 2026 after hearings”:

- a. Please provide PG&E’s anticipated timeline for conducting and releasing the results of a new RO model update after the hearings in this proceeding.
- b. Please provide PG&E’s anticipated timeline for issuing customer refunds for overcollections resulting from including the DCPD DTA in its revenue requirement calculation, should PG&E’s update occur after the close of this proceeding.

**ANSWER 002**

- a. The scoping memo currently does not identify when the Results of Operation (RO) Model should be updated. PG&E is in the process of determining when the next RO Model update will take place.
- b. It is expected that the RO Update will occur during the pendency of this case, so the need to issue refunds after a final decision is unlikely to occur.

Nevertheless, should the RO Update occur after a final decision is issued in the 2027 GRC, then PG&E proposes to (1) file a Tier 2 advice letter regarding any revenue requirement change and (2) propose to reflect the revenue requirement update in the next Annual Electric True-Up (AET) filing or another rate change advice letter. This proposal was also discussed in PG&E’s testimony in PG&E-10, Chapter 10, page 10-8, lines 9 through 13.

**PACIFIC GAS AND ELECTRIC COMPANY  
2027 General Rate Case Phase I  
Application 25-05-009  
Data Response**

<b>PG&amp;E Data Request No.:</b>	CalCCA_018-Q003
<b>PG&amp;E File Name:</b>	GRC-2027-PhI_DR_CalCCA_018-Q003
<b>Request Date:</b>	April 7, 2026
<b>Requester DR No.:</b>	018
<b>Requesting Party:</b>	California Community Choice Association
<b>Requester:</b>	Julia Kantor
<b>Date Sent:</b>	April 21, 2026
<b>PG&amp;E Witness(es):</b>	Kerry Hegarty – Finance

**QUESTION 003**

Refer to Exh. PG&E-22 at 7-36:25-27, where PG&E states that “an update to CPUC-jurisdictional revenue requirements for 2027 through 2030 will be necessary”:

- a. Please provide PG&E’s anticipated timeline for “provid[ing] an update once a sufficient amount of data has been acquired.”
- b. Please explain how and when PG&E plans to update its revenue requirement and issue customer refunds for overcollections resulting from PG&E’s failure to include an implementation of FERC Order No. 898 in its 2027 GRC Application.

**ANSWER 003**

At this time, PG&E does not have a proposed method or timeline for updates to its 2027 GRC revenue requirement for potential changes resulting from FERC Order No. 898.

**PACIFIC GAS AND ELECTRIC COMPANY  
2027 General Rate Case Phase I  
Application 25-05-009  
Data Response**

<b>PG&amp;E Data Request No.:</b>	CalCCA_018-Q004
<b>PG&amp;E File Name:</b>	GRC-2027-PhI_DR_CalCCA_018-Q004
<b>Request Date:</b>	April 7, 2026
<b>Requester DR No.:</b>	018
<b>Requesting Party:</b>	California Community Choice Association
<b>Requester:</b>	Julia Kantor
<b>Date Sent:</b>	April 21, 2026
<b>PG&amp;E Witness(es):</b>	Kerry Hegarty – Finance

**QUESTION 004**

Refer to Exh. PG&E-22 at 7-31:9-12, where PG&E states: “PG&E’s treatment is consistent with the Commission’s long-standing application of the ‘used and useful’ standard, which evaluates rate base treatment based on the totality of facts and circumstances rather than operational status alone”: please provide references to the Commission precedent referenced here.

**ANSWER 004**

In D.11-05-018, regarding cost recovery for retired meters the Commission stated<sup>1</sup>:

The Commission has determined that plant which is not used and useful should be excluded from rate base (and therefore excluded from earning a rate of return). However, as a number of parties have noted, the Commission has also made exceptions to this general policy. In doing so, the causes, as well as the burdens and benefits of the plant items in question, have been taken into consideration in determining appropriate ratemaking balances and solutions. The particular circumstance of each situation has been, and must be, evaluated in making these determinations.

As explained in PG&E’s rebuttal testimony<sup>2</sup>, PG&E considers multiple factors in the potential retirement of hydroelectric facilities and associated assets, not just whether the facilities have ceased power generation. Other conditions that must be taken into consideration are whether PG&E has received FERC approval for the license surrender (if the facility has a FERC license), authorization from the California Independent System Operator (CAISO) for permanent retirement, or if there are remaining operational assets associated with the facility that continue to serve water conveyance functions and thus still provide customer and public value.

---

<sup>1</sup> D.11-05-018, p.55

<sup>2</sup> Exhibit PG&E-22, Chapter 7, pp. 7-30 to 7-31.

**PACIFIC GAS AND ELECTRIC COMPANY  
2027 General Rate Case Phase I  
Application 25-05-009  
Data Response**

<b>PG&amp;E Data Request No.:</b>	CalCCA_018-Q005
<b>PG&amp;E File Name:</b>	GRC-2027-PhI_DR_CalCCA_018-Q005Supp01
<b>Request Date:</b>	April 7, 2026
<b>Requester DR No.:</b>	018
<b>Requesting Party:</b>	California Community Choice Association
<b>Requester:</b>	Julia Kantor
<b>Date Sent:</b>	April 21, 2026 (Original) April 24, 2026 (Supplemental)
<b>PG&amp;E Witness(es):</b>	Donna Barry – Energy Policy and Procurement Ned Allis – Depreciation Study

**QUESTION 005**

Refer to Exh. PG&E-17 at 7-41:3-10, where PG&E discusses PG&E and CalCCA’s “fundamental disagreement on the proper definition of a UOG facility’s economic and/or depreciable life”:

- a. What is PG&E’s definition of an “asset life” for purposes of ratemaking in general (i.e., setting depreciation rates)?
- b. What is PG&E’s definition of an “asset life” for purposes of PCIA vintaging/re-vintaging? If different from the definition provided in subpart (a), please explain why PG&E defines these differently.
- c. What is PG&E’s definition of an “asset life extension” for purposes of ratemaking in general (i.e., setting depreciation rates)?
- d. What is PG&E’s definition of an “asset life extension” for purposes of PCIA vintaging/re-vintaging? If different from the definition provided in subpart (c), please explain why PG&E defines these differently.
- e. Confirm or deny: PG&E uses an asset’s estimated end of life date in its depreciation study to calculate the asset’s remaining life (i.e., the years between the current year and the end of life year), which it then uses to calculate depreciation rates. If deny, please explain.
- f. Confirm or deny: end of life dates in PG&E’s depreciation study are the specific or probable retirement dates used for purposes of ratemaking that are adopted by PG&E’s experts based on their best professional judgement. If deny, please explain.
- g. Confirm or deny: PG&E uses the end of life date assumptions from its depreciation study to set depreciation rates such that it is able to recover the revenue requirement associated with the asset by that asset’s end of life date. If deny, please explain.

**ANSWER 005**

a. PG&E uses the same definition for asset life in this context as the definition of service life in the Uniform System of Accounts, which is “Service life means the time between the date electric plant is includible in electric plant in service, or electric plant leased to others, and the date of its retirement.”

b. The Commission has not adopted a definition of “asset life” for utility-owned generation facilities, for purposes of PCIA vintaging/re-vintaging.

PG&E expects the topic of developing UOG re-vintaging guidelines to be scoped into Track 3 of the PCIA Reform Rulemaking (R.) 25-02-005 and recommends defining a utility-owned generation facility’s lifespan for purposes of the PCIA Re-vintaging be addressed in that proceeding, which will include the other investor-owned utilities, as well as other interested parties.

c. In the context of a depreciation study, PG&E would define “asset life extension” to mean a change in service life to a longer life than currently used for depreciation purposes.

d. The Commission has not adopted a definition for “asset life extension” for purposes of PCIA vintaging/re-vintaging. A prerequisite to adopting a definition for “asset life extension” seems to be properly defining a generation facility’s “asset life.”

PG&E expects the PCIA Reform Rulemaking to include the topic of developing UOG re-vintaging guidelines in Track 3 of that proceeding and developing a formal definition for each generating facility’s lifespan and lifespan extension, separate and distinct from the depreciation life presented in PG&E’s depreciation studies, can be addressed most efficiently in that proceeding.

e. Confirm in part. It is correct that the composite remaining life is used to calculate depreciation rates. PG&E uses group depreciation and there are different methods used to calculate the estimated composite remaining life, depending on the assets studied. For example, survivor curves are used for many asset classes, which do not have specific estimated end of life dates. For hydro assets, the composite remaining lives are weighted averages based on both estimated end of life dates for a given hydro facility and interim survivor curves.

f. Confirmed, although as discussed in the response to subpart (e), end of life dates are used for a subset of PG&E’s assets (primarily electric generating facilities). For hydroelectric facilities, the professional judgment includes consideration of FERC license expiration dates.

g. Confirm in part and deny in part. The end of life date assumptions in the depreciation study are used to establish depreciation rates that are intended to allocate the service value of capital assets over their useful lives. PG&E’s depreciation rates are established on a group basis rather than on an asset basis. Estimated depreciation expense is included as a component of the revenue requirement.

**ANSWER 005 SUPPLEMENTAL 01**

b. PG&E has not developed a definition for a UOG facility’s “asset life” for purposes of defining the term (i.e., length of time) that a UOG facility remains eligible for PCIA cost recovery. The concept that term of the PCIA cost recovery should be defined

by the expected life of a generation asset, or expected retirement date, as used in PG&E's depreciation studies, was included in the Joint Community Choice Aggregators (CCA) Testimony in PG&E's 2023 GRC, A.21-06-021.<sup>1</sup>

Specifically, the Joint CCAs recommendation in the 2023 GRC was that as a condition of approving PG&E's updated depreciation study:

- i. The Commission order PG&E to change the vintaging treatment for 12 UOG hydroelectric resources CalCCA asserted had recently received a life extension or had a proposed life extension through PG&E's updated depreciation studies<sup>2</sup> and,
- ii. A new vintaging framework be approved going forward where certain new costs or changes to a facility would be recognized as new commitments that trigger reconsideration of that facility's vintage assignment in recognition that PG&E is undertaking these investments and changes on behalf of bundled customers.<sup>3</sup>

The Commission denied the request to adopt CalCCA's recommendation to re-vintage the 12 hydro facilities based on the updated depreciation studies, citing to the decisions issued in the 2017 PCIA OIR.<sup>4</sup> The Commission also declined to adopt the re-vintaging framework proposed by the Joint CCAs suggesting that addressing a re-vintaging framework would be best considered a broader proceeding in which other utilities and stakeholder positions may be considered.<sup>5</sup>

While PG&E understands CalCCA's desire to eliminate cost responsibility for PG&E's UOG through the PCIA based on a defined date, PG&E does not believe that the depreciation study's expected retirement date, whether that is based on the current FERC license term, or some expected future license term that is pending approval at FERC, is the right metric on which to base the PCIA cost recovery term for its UOG facilities. The Commission agreed with this position in the final 2023 GRC decision (D.23-11-069) when it declined to approved the Joint CCA's recommendation. A metric for length of time a UOG generation remains PCIA-eligible could be developed independent of the generation facility's "asset life" as defined in the utility's depreciation studies. A metric that is more stable, and

- 
- <sup>1</sup> The Joint CCAs include the City and County of San Francisco (CleanPowerSF), East Bay Community Energy (EBCE), Marin Clean Energy (MCE), Peninsula Clean Energy Authority (PCE), Pioneer Community Energy, San José Clean Energy (SJCE), Silicon Valley Clean Energy Authority (SVCE), and Sonoma Clean Power Authority (SCP).
  - <sup>2</sup> See Joint CCAs Direct Testimony, Executive Summary, page ii, filed on June 13, 2022.
  - <sup>3</sup> Ibid., page iii.
  - <sup>4</sup> See D.23-11-069, p. 510: "The relevant decisions about PCIA vintaging (D.08-09-012 and D.18-10-019) do not suggest that PG&E's proposed depreciation of the assets would trigger a re-vintage for the departed load customers. The Commission's relevant discussions emphasize that customers are vintaged (or bound) based on whether they were bundled customers at the inception of the contract, such as when the IOU executed a contract or began construction of a new generation resource (see D.08-09-012 at 61) The Joint CCAs fail to present sufficient evidence to establish that PG&E's proposed depreciation change is akin to a "significant overhaul" or "plant investments for certain upgrades" to the assets. For this reason, the Commission denies the Joint CCAs' request."
  - <sup>5</sup> Ibid, page 511.

transparent, could produce better outcomes for both the utility's bundled customers and for unbundled customers served by the CCAs.

PG&E is also concerned that any precedent set in this PG&E specific GRC for defining the term of the UOG cost recovery for the PCIA that is based on generation facility's lifespan would negatively impact outcomes in the other investor-owned utilities (IOUs) GRCs.

This is why the Joint IOUs recommended addressing the establishment of standards for re-vintaging UOG resources as part of Track 3 of the PCIA Reform Rulemaking.<sup>6</sup> As noted in opening comments on Track 3, the Joint IOUs believe that the question of the standard for when re-vintaging of UOG would occur should be included in Track 3B of PCIA Reform Rulemaking, so as to allow parties time to develop a complete evidentiary record through testimony.

Development of standards for re-vintaging, that include needed definitions that are clear and concise, that would subsequently be applicable to case-by-case assessments of activities proposed in each IOU's General Rate Cases, could then be applied uniformly.

---

<sup>6</sup> See Joint IOUs March 27, 2026, Opening Comments on The Administrative Law Judge's Ruling Authorizing Parties to File Comment on Issues to Address in Track 3 of the PCIA Rulemaking (R.) 25-02-005.

**PACIFIC GAS AND ELECTRIC COMPANY  
2027 General Rate Case Phase I  
Application 25-05-009  
Data Response**

<b>PG&amp;E Data Request No.:</b>	CalCCA_018-Q006
<b>PG&amp;E File Name:</b>	GRC-2027-Phi_DR_CalCCA_018-Q006
<b>Request Date:</b>	April 7, 2026
<b>Requester DR No.:</b>	018
<b>Requesting Party:</b>	California Community Choice Association
<b>Requester:</b>	Julia Kantor
<b>Date Sent:</b>	April 21, 2026
<b>PG&amp;E Witness(es):</b>	Donna Barry – Energy Policy and Procurement

**QUESTION 006**

Refer to Exh. PG&E-17 at 7-45:15-22 (where PG&E recommends that CalCCA’s specific recommendations to re-vintage a subset of PG&E’s Hydro Facilities be set aside until a comprehensive set of UOG Revintaging Guidelines are approved in the PCIA Reform OIR”) and to Exh. PG&E-17 at 7-36:3 to 7-37:24: please confirm or deny that the Commission has required “PG&E to provide specific information about its resources and investment plans for its UOG portfolio, and an assessment on whose behalf the investment was being made in future GRCs,” to facilitate “consideration of proposed changes to assets regardless of whether any broader framework is adopted.” If deny, please explain.

**ANSWER 006**

Confirm.

**PACIFIC GAS AND ELECTRIC COMPANY**  
**2027 General Rate Case Phase I**  
**Application 25-05-009**  
**Data Response**

<b>PG&amp;E Data Request No.:</b>	CalCCA_018-Q007
<b>PG&amp;E File Name:</b>	GRC-2027-PhI_DR_CalCCA_018-Q007Supp01
<b>Request Date:</b>	April 7, 2026
<b>Requester DR No.:</b>	018
<b>Requesting Party:</b>	California Community Choice Association
<b>Requester:</b>	Julia Kantor
<b>Date Sent:</b>	April 21, 2026 (Original) April 24, 2026 (Supplemental)
<b>PG&amp;E Witness(es):</b>	Donna Barry – Energy Policy and Procurement

**QUESTION 007**

Refer generally to Exh. PG&E-17 at 7-32 to 7-42:

- a. Confirm or deny: the two most significant benefits associated with PG&E’s hydro assets are their energy value and capacity value. If deny, please explain.
- b. Confirm or deny: generally, PG&E only has energy and capacity obligations on behalf of its bundled customers. If deny, please explain.
- c. Under what circumstances is PG&E authorized to procure generation resources on behalf of unbundled customers? Please provide a comprehensive list of all such circumstances.
- d. Under what circumstances is PG&E authorized to procure RA assets on behalf of unbundled customers? Please provide a comprehensive list of all such circumstances.
- e. Confirm or deny: CCAs are separately required to meet their own RA requirements on behalf of their customers. If deny, please explain.
- f. Confirm or deny: CCAs do not recover any energy or capacity costs associated with their generation resources from PG&E’s bundled customers. If deny, please explain.
- g. During the last five years, has PG&E used any of the following assets to fulfill its RA requirements: Phoenix, DeSabra-Centerville, Helms, Balch, Drum Spaulding, Kerckhoff 2, McCloud-Pit, and Upper NF Feather River?
  - i. If so, please list which assets were used during which compliance period(s).
  - ii. If so, were any of the RA attributes allocated to CCAs?
- h. Confirm or deny: if PG&E were to decide to buy RA on the market to satisfy its RA obligations, the associated costs would only be recovered from PG&E’s bundled customers. If deny, please explain.

## ANSWER 007

- a. Deny. PG&E operates its Hydro facilities in accordance with its Federal Energy Regulatory Commission (FERC) hydropower licenses which are comprehensive, binding documents that dictate how a project is constructed, operated, and maintained.

The terms and conditions of the FERC license include standard articles and mandatory conditions for environmental, cultural, and recreational resources that surround the watershed as well as mandatory conditions imposed by federal land management agencies, the US Fish and Wildlife Services or NOAA, and settlement agreements with other external stakeholders.

These standard articles and mandatory conditions are co-equal benefits, along with the energy and capacity benefits.

Some typical conditions included in the FERC license requirements include:

### 1. Operational Requirements

- *Minimum Flows*: Mandated water releases to protect aquatic habitats downstream.
- *Reservoir Level Management*: Specific requirements for managing water levels to balance power generation with environmental or recreational needs.
- *Operational Flexibility*: Restrictions on how quickly or frequently a plant can change generation levels (ramping rates) to minimize impacts on downstream water levels.
- *Dam Safety*: Requirements for regular safety inspections, monitoring, and structural maintenance.

### 2. Environmental Mitigation and Enhancement

- *Fish Passage & Protection*: Construction and operation of fish ladders, screens, or other devices to allow safe fish movement upstream and downstream.
- *Water Quality Standards*: Mandatory compliance with state-issued 401 Water Quality Certifications, which often limit turbidity and temperature changes.
- *Wildlife Habitat Protection*: Requirements to protect threatened or endangered species, often involving specific habitat restoration projects or studies.
- *Shoreline Management Plans*: Regulations concerning the use of project lands and shorelines to manage erosion and development.

### 3. Public Use and Cultural Resources

- *Recreation Facilities*: Mandated construction and maintenance of boat launches, fishing access, hiking trails, and picnic areas.
- *Cultural Resource Management*: Implementation of plans to identify and protect archaeological or historic sites, often requiring a Historic Properties Management Plan (HPMP).

### 4. Administrative and Legal Conditions

- *License Term*: Licenses are generally issued for 40 years for non-federal projects.
- *Compliance Monitoring*: Requirement for filing annual reports and allowing FERC inspections.
- *Transfer of License*: Prior Commission approval is required to sell or transfer the license.
- *Headwater Benefits*: Requirements to pay fees for benefits derived from upstream projects.

## 5. Key Mandatory Conditions

- *Section 4(e) Conditions*: Mandatory conditions imposed by federal land management agencies (e.g., U.S. Forest Service) if the project is located on federal reservations.
  - *Section 18 Prescriptions*: Mandatory fishway prescriptions set by the U.S. Fish and Wildlife Service or NOAA Fisheries.
  - *Settlement Agreements*: Many licensees enter into negotiated settlements with stakeholders (NGOs, tribes, state agencies) that are incorporated into the final license, often driving the specific environmental measures
- b. PG&E is obligated to procure resources in accordance with the Commission's directives which generally require procurement only for PG&E's bundled customers. The exceptions are described in response 7.c.
- c. PG&E, as the provider of last resort, has several procurement-related obligations that it recovers from all retail load or opt-out load serving entities (LSE), where the procurement obligations are required by statute and / or are directed by Commission decisions.

Those procurement obligations include:

1. *Tree Mortality (TM) contract costs*: resources procured in compliance with Senate Bill (SB) 859 and Resolutions E-4770 and E-4805, as defined in Decision 18-12-003. TM net costs are recovered through the Tree Mortality Non-bypassable Charge Balancing Account (TMNBCBA), and consolidated in the Public Purpose Program rate.
2. *Bioenergy Market Adjustment Tariff (BioMAT) contracts*: resources procured in compliance with Senate Bill (SB) 1122, as revised in Decision (D.) 20-08-043. BioMAT net costs recovered through the BioMAT Non-bypassable Charge Balancing Account (BNBCBA), which is consolidated in the Public Purpose Program rate.
3. *New PURPA qualifying facility (QF) contract costs*: resources procured pursuant to D.10-12-035 for new PURPA Standard Offer (SO) contracts. New PURPA SO contracts' net costs are recovered in Public Policy Charge Balancing Account, Public Policy Procurement Subaccount and recovered from all retail customers through the Public Purpose Program rate.
4. *Opt-out Procurement contracts*: Modified Cost Allocation Mechanism (CAM) contract targets for all LSEs were set in D.19-11-016 and included the ability for non-IOU LSEs to opt-out of its procurement obligation and elect that the IOU procure on behalf of the LSE. PG&E had several LSEs in its service

territory that opted out of its procurement obligation, which required PG&E to procure incremental MW above its bundled compliance need to support opt-out LSEs that chose not to procure its assigned MW target. The modified cost allocation mechanism (CAM) contract costs are recorded to the Modified Cost Allocation Mechanism Balancing Account (MCAMBA) and will be recovered from customers of the opt-out LSEs, which includes one CCA.

5. *Backstop Procurement*: Pursuant to D.22-05-015, OP 10, the Commission authorized recovery of opt-out or backstop procurement in the event that a non-investor-owned-utility (IOU) load serving entity (LSE) declares bankruptcy or ceases providing retail service in California, and the non-IOU LSE has a procurement obligation under D.19-11-016, D.21-06-035, or any subsequent procurement order under the IRP framework, the remaining capacity and associated procurement obligations under the IRP framework should revert to the relevant IOU. Exceptions to this rule can be made in cases where the non-IOU LSE's customers transfer to another non-IOU LSE, as was the case for opt-out load in SDG&E's territory, see OP 14 of D.22-05-015.
6. *Summer Reliability*: Commission orders in the Integrated Resource Plan proceedings have included requirements that the investor-owned utilities (IOUs) procure incremental resources for all retail customers up to an effective planning resource margin of 17.5 percent to meet summer reliability needs.

Specifically, D.21-02-028 and D.21-03-056 authorized the IOUs to continue their procurement efforts and endeavor to meet and exceed their respective incremental procurement targets to achieve an effective 17.5 percent planning reserve margin (PRM) for the months of May through October 2021 and 2022. Increasing the PRM from 15 percent to an effective 17.5 percent results in a minimum incremental procurement target of 450 megawatts (MW) for PG&E. The Decision stated that resource adequacy (RA) resources in excess of an IOU's 15 percent PRM should be charged to all benefiting customers in the IOU's service territory via the CAM and authorizes the IOUs to acquire and pair imports with maximum import capability to be included in CAM procurement costs.

D.21-12-015 instructed the IOUs to solicit additional resources for summers 2022 and 2023, including a new target range of 900 MW to 1,350 MW for PG&E for each of the June – October summer months of 2022 and 2023. Resource types to be considered for procurement include Resource Adequacy (RA)-only contracts and incremental capacity from revised power purchase agreements. Also, D.21-12-015, OP 13 ordered the IOUs to seek DR RA Resources from third-party Demand Response Providers (DRPs) through a "bilateral" contracting process.

D.23-06-029 found it reasonable to update the PRM to 17 percent and to maintain the effective PRM for summer reliability adopted in D.21-12-015 for the 2024 and 2025 RA years. The PRM requirement of 17 percent results in effective PRM target for PG&E of 765 - 1,440 MW for each of the June – October summer months of 2024 and 2025

7. Resources eligible for the Cost Allocation Mechanism (CAM) are recovered through New System Generation New System Generation Balancing Account (NSGBA), from all retail load. Resources designated as CAM-eligible are determined by the Commission and cost and benefits of the resources are allocated to all Retail Load.

A comprehensive list of the procurement recovered through the NSGBA is listed below and includes procurement obligations mentioned in items 3 and 6 above. This list highlights both past procurement and current procurement obligations that are (or were) CAM-eligible, as well as CAM-eligible Summer Reliability resources mentioned in item 6. Each category of costs has a separate subaccount established in the NSGBA.

1. Qualifying Facility, Combined Heat and Power Program costs.
  2. Marsh Landing Power Purchase Agreement.
  3. Vistra Moss Landing Energy Storage Resource Adequacy Agreement
  4. Hummingbird Energy Storage Resource Adequacy Agreement
  5. mNOC AERS Behind-the-Retail Meter Capacity Storage Agreement
  6. Elkhorn Energy Storage Facility
  7. CPE Centralized Local Procurement
  8. Modified Cost Allocation Mechanism
  9. Summer Reliability Incremental Procurement
    - Amendments to Existing Purchase Power Agreements for Incremental Energy
    - Firm Import Energy
    - System Reliability Procurement
    - Transfer of Resource Adequacy to / from other balancing accounts, as authorized by the Commission.
- d. See PG&E's response to 7.c. In addition, the Commission has authorized the Central Procurement Entity (CPE) in PG&E's Service Territory to procure RA contracts to meet local reliability needs. These resources have been designated as eligible for the Cost Allocation Mechanism, which is recovered through the New System Generation Balancing Account (NSGBA) from all retail customers.
  - e. Confirm.
  - f. Confirm, but noting limited exceptions.

The first exception is associated with the CCA's Disadvantaged Community (DAC) Green Tariff Programs, which are recovered through Public Policy Charge Balancing Account (PPCBA). Costs in the PPCBA are recovered through Public Purpose Program (PPP) rate, from all retail load, including bundled customers. There are 5 CCAs that have DAC Green Tariff Program subaccounts, each with a separate subaccount in the PPCBA.

The second exception is for CCAs that pursue mandated BioMAT contracts. CCAs BioMAT net costs are eligible to be recovered through the BioMAT Non-bypassable

Charge Balancing Account (BNBCBA), and a separate subaccount has been established for the CCA's BioMAT program costs. These costs are recovered from all retail customers, including PG&E's bundled customers, and are consolidated in the Public Purpose Program rate.

- g. i. Please see Attachment "*GRC-2027-Phi\_DR\_CalCCA\_018-Q007Atch01.xlsx*" which indicates when the resource was used to meet bundled customer needs and when the resource was used for substitution for a CAM eligible resource by month and year, for years 2021 - 2025.
- ii. Yes, when resources were used for RA substitution, MW were allocated as part of the Cost Allocation Mechanism process.
- h. Confirm, with the procurement obligation exceptions noted in response to 7.c.

**ANSWER 007 SUPPLEMENTAL 01**

- g. i. Please see PG&E's Supplemental Attachment "*GRC-2027-Phi\_DR\_CalCCA\_018-Q007Supp01Atch01.xlsx*", which now includes Helms.









**PACIFIC GAS AND ELECTRIC COMPANY**  
**2027 General Rate Case Phase I**  
**Application 25-05-009**  
**Data Response**

<b>PG&amp;E Data Request No.:</b>	CalCCA_018-Q008
<b>PG&amp;E File Name:</b>	GRC-2027-PhI_DR_CalCCA_018-Q008
<b>Request Date:</b>	April 7, 2026
<b>Requester DR No.:</b>	018
<b>Requesting Party:</b>	California Community Choice Association
<b>Requester:</b>	Julia Kantor
<b>Date Sent:</b>	April 21, 2026
<b>PG&amp;E Witness(es):</b>	Donna Barry – Energy Policy and Procurement

**QUESTION 008**

Refer to Exh. PG&E-17 at 7-27:26 to 7-28:6:

- a. Under what circumstances are the referenced benefits “allocated to load serving entities (i.e., RPS) that serve customers that pay PCIA rates”?
- b. Please explain in more detail how the provision of local RA compliance attributes reduces the procurement cost of local RA for CCA customers.

**ANSWER 008**

- a. Through the Voluntary Allocation and Market Offer (VAMO) Process, which was authorized in D.21-05-030. D.21-05-030 was issued on May 24, 2021, as part of Phase 2 of the 2017 PCIA Rulemaking and addresses portfolio optimization activities associated with RPS resources subject to PCIA cost recovery.

A VAMO mechanism was adopted, including authorizing a process for the IOUs to allocate a “slice” of an IOU’s entire PCIA-eligible RPS portfolio to eligible load-serving entities (“LSEs”) in proportion their vintaged, forecasted annual load share. LSE’s that selected voluntary allocations executed agreements with PG&E to receive an RPS allocation of the PCIA-eligible portfolio in exchange for compensation using the RPS market price benchmark adopted in the annual ERRRA Forecast Proceeding.

- b. The Central Procurement Entity (CPE) is required to procure local resources for all customers in PG&E’s service territory, and those costs are recovered through the New System Generation Balancing Account from retail customers. PG&E’s utility-owned generation (UOG) resources that provide local resource adequacy benefits can be shown to the CPE or sold directly to the CPE.

Shown resources have no associated costs and the local RA attributes from the UOG can be counted against the CPE’s RA target, which lowers the CPE’s open position.

UOG local RA can also be sold to the CPE and the sales revenue benefits non-exempt departing load paying PCIA by crediting the Portfolio Allocation Balancing Account and debiting the CPE Subaccount in the NSGBA.

**PACIFIC GAS AND ELECTRIC COMPANY**  
**2027 General Rate Case Phase I**  
**Application 25-05-009**  
**Data Response**

<b>PG&amp;E Data Request No.:</b>	CalCCA_018-Q009
<b>PG&amp;E File Name:</b>	GRC-2027-PhI_DR_CalCCA_018-Q009
<b>Request Date:</b>	April 7, 2026
<b>Requester DR No.:</b>	018
<b>Requesting Party:</b>	California Community Choice Association
<b>Requester:</b>	Julia Kantor
<b>Date Sent:</b>	April 21, 2026
<b>PG&amp;E Witness(es):</b>	Donna Barry – Energy Policy and Procurement

**QUESTION 009**

Refer generally to Exh. PG&E-17 at 7-42 to 7-44:

- a. From PG&E’s perspective, under what circumstances would a change in function occur for a generation asset?
- b. Under what circumstances does PG&E operate a generation resource not in accordance with least-cost dispatch?
- c. Refer also to Exh. PG&E-17 at 7:43:27-28, where PG&E states: “[h]ydro dispatch is not tied to bundled load needs at all”:
  - i. Please explain in more detail what PG&E means by this statement.
  - ii. Is PG&E’s hydro dispatch tied to overall load needs in PG&E’s service territory? Please explain.
  - iii. Is PG&E’s hydro dispatch impacted by its bundled customers’ load needs? Please explain.
  - iv. Is PG&E’s generation asset procurement tied to its bundled customers’ load needs? Please explain.
  - v. When PG&E decides whether to retire or reinvest in one of its generation assets, does it consider its bundled customers’ load needs? Please explain.

**ANSWER 009**

- a. The term, “change in function” was introduced in D.23-11-069 and was never defined by Commission. For the UOG portfolio, PG&E cannot imagine what circumstances would lead to a conclusion that there was a change in function.
- b. Never.
- c.
  - i. As explained in PG&E’s Bundled Procurement Plan, Commission has adopted Standards of Conduct (SOC) for procurement-related activities, including SOC 4 which provides that the utilities should dispatch their

generation resources in a least-cost manner. The Commission has recognized that with the California Independent System Operator's (CAISO) implementation of its Market Redesign and Technology Upgrade (MRTU), "[t]he regulated energy utility is responsible for scheduling and bidding its generation to the CAISO, but once that is done, it is the CAISO's responsibility to dispatch the generation."<sup>1</sup>

All resources are scheduled or bid into the CAISO markets based on their incremental cost/opportunity cost, or self-scheduled based on constraints that limit their ability to be bid. The fundamental principle of LCD is to ensure that PG&E's dispatchable resources are used when their incremental costs or opportunity costs are below the cost of energy in the CAISO wholesale markets. By appropriately scheduling and bidding its resources into the CAISO markets at their incremental or opportunity costs, PG&E ensures that total procurement to meet customer demand in the CAISO markets is at least cost.

PG&E has adopted the following principles to guide its scheduling and bidding activities:

- PG&E aims to minimize its total cost of energy required to meet load and A/S requirements, subject to regulatory, legal, operational, contractual, and financial requirements.
- PG&E's scheduling and bidding process considers all regulatory, legal, operational, contractual and financial requirements.
- PG&E minimizes energy costs by explicitly considering the incremental costs of all resources available to it in scheduling or bidding decisions.
- PG&E integrates any local area reliability, day-ahead scheduling requirements, and deliverability requirements into its scheduling or bidding decisions.
- The CAISO markets perform LCD for all resources bid/scheduled into the markets based on information provided by all market participants, transmission information that is solely available to the CAISO, and information regarding system conditions that are solely available to the CAISO.
- The parameters and forecasts that PG&E has ability to control with regard to LCD are the following: load forecast, market price forecast, incremental heat rate, and master file submission. These parameters and forecasts are used in the calculation of submitted bids and/or schedules.
- LCD activities are subject to forecast and market uncertainties, including those associated with actual customer loads, behavior of other market participants, actual energy deliveries from Qualifying Facilities and intermittent resources, non-public transmission constraints, and CAISO reliability-based discretionary decisions.

ii. No. See response to c.i.

---

<sup>1</sup> Decision 14-05-023, Finding of Fact 15

- iii. No. See response to c.i.
- iv. Yes. New incremental procurement ordered through the Integrated Resource Plan Proceeding is tied to bundled customers' forecast load needs, which would consider baseline resources already existing in PG&E's portfolio, to determine the incremental procurement target MW PG&E would be expected to procure.
- v. No. PG&E considers the benefits and the costs of the resource, independent of forecast bundled load.

**PACIFIC GAS AND ELECTRIC COMPANY**  
**2027 General Rate Case Phase I**  
**Application 25-05-009**  
**Data Response**

<b>PG&amp;E Data Request No.:</b>	CalCCA_018-Q010
<b>PG&amp;E File Name:</b>	GRC-2027-PhI_DR_CalCCA_018-Q010
<b>Request Date:</b>	April 7, 2026
<b>Requester DR No.:</b>	018
<b>Requesting Party:</b>	California Community Choice Association
<b>Requester:</b>	Julia Kantor
<b>Date Sent:</b>	April 21, 2026
<b>PG&amp;E Witness(es):</b>	Donna Barry – Energy Policy and Procurement

**QUESTION 010**

Refer to Exh. PG&E-17 at 7-27:23-25, where PG&E states “[t]he revenue received in the CAISO energy markets is credited in the PCIA ratemaking mechanism as part of the market revenue that offset total costs of these resources”:

- a. The amount of market revenue received for an asset will impact whether the asset at issue will contribute to PCIA rates going up, staying steady, or going down, correct?
- b. Confirm or deny that there is a financial risk (i.e., risk of PCIA rate increase) to unbundled customers associated with hydro assets assigned to the Legacy UOG Vintage. If deny, please explain.
- c. If a hydro asset was removed from the Legacy UOG Vintage, there would not be any financial risk to unbundled customers associated with the asset, correct?
- d. In the past 10 years, please note if and when the PCIA revenue requirement associated with Legacy UOG has resulted in a net credit amount.

**ANSWER 010**

- a. No. However, the amount of CAISO market revenues received for a single resource will determine whether the resource has above market costs or not. The PCIA rate depends on many other factors than a single resource’s CAISO market revenues.
- b. All bundled and non-exempt unbundled customers are exposed to same financial risk, which might be better characterized as market risk rather than financial risk.
- c. No. If a hydro asset was removed from the Legacy UOG vintage and reassigned as a 2027 (or later) vintage asset, incremental departing load after 2027 (or later), would continue to be responsible for the above market cost of the resources along with bundled load.
- d. PG&E only has recorded actuals for PCIA eligible resources since 2019 and thus, can provide PG&E’s legacy UOG portfolio above market costs results for years 2019 – 2025, which are shown in the table below.

<b>PABA Record Net Costs</b>						
<b>Legacy Utility Owned Generation Subaccount</b>						
<b>Net Above Market Costs (Dollars)</b>						
<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>2024</b>	<b>2025</b>
\$159,982,346	\$104,341,067	(\$1,189,459)	(\$418,875,753)	(\$33,351,531)	(\$3,319,674)	\$387,007,997

**PACIFIC GAS AND ELECTRIC COMPANY**  
**2027 General Rate Case Phase I**  
**Application 25-05-009**  
**Data Response**

<b>PG&amp;E Data Request No.:</b>	CalCCA_018-Q011
<b>PG&amp;E File Name:</b>	GRC-2027-PhI_DR_CalCCA_018-Q011
<b>Request Date:</b>	April 7, 2026
<b>Requester DR No.:</b>	018
<b>Requesting Party:</b>	California Community Choice Association
<b>Requester:</b>	Julia Kantor
<b>Date Sent:</b>	April 21, 2026
<b>PG&amp;E Witness(es):</b>	Rebecca Doidge – Generation

**QUESTION 011**

Refer to Exh. PG&E-17 at 7-39:21 to 7-40:29:

- a. Confirm or deny: when PG&E files a relicensing application at FERC, it is making an affirmative decision that it would like to continue to operate and invest in these generation assets beyond the current FERC license term. If deny, please explain.
- b. Confirm or deny: generally, PG&E is not required to file relicensing applications at FERC for its hydro assets. If deny, please explain.
- c. Confirm or deny: generally, PG&E has other alternatives it considers when it is deciding whether to file a relicensing application at FERC (like divestiture, license surrender, or retirement). If deny, please explain.
- d. (d) Confirm or deny: when PG&E determines whether to sell, retire, or relicense a hydro facility, it takes into account its bundled customers' energy and/or RA compliance needs. If deny, please explain.
- e. Confirm or deny: when PG&E determines whether to sell, retire, or relicense a hydro facility, it generally does not take into account unbundled customers' energy and/or RA compliance needs. If deny, please explain.
- f. Confirm or deny: in granting a relicensing application, FERC may impose new licensing requirements on PG&E that were not associated with PG&E's original generation commitment or original asset license. If deny, please explain.
- g. In a hypothetical scenario in which PG&E had zero bundled service customers, could PG&E continue to pursue FERC relicensing for its hydro assets? If so, who would pay for the associated capital reinvestments, and who would bear the risks associated with these investments?

**ANSWER 011**

- a. Confirm.
- b. Confirm.
- c. Confirm.

- d. Neither. Decisions to sell or retire a resource are driven by factors other than PG&E's bundled load. Decisions to relicense these facilities would take into consideration the benefits and the costs of the resource, independent of forecast bundled load.
- e. Confirm.
- f. Confirm.
- g. PG&E objects to this question as vague. Subject to that objection, PG&E responds that it does not know what the path forward would be in the hypothetical scenario presented

**PACIFIC GAS AND ELECTRIC COMPANY  
2027 General Rate Case Phase I  
Application 25-05-009  
Data Response**

<b>PG&amp;E Data Request No.:</b>	CalCCA_018-Q012
<b>PG&amp;E File Name:</b>	GRC-2027-PhI_DR_CalCCA_018-Q012
<b>Request Date:</b>	April 7, 2026
<b>Requester DR No.:</b>	018
<b>Requesting Party:</b>	California Community Choice Association
<b>Requester:</b>	Julia Kantor
<b>Date Sent:</b>	April 21, 2026
<b>PG&amp;E Witness(es):</b>	Donna Barry – Energy Policy and Procurement

**QUESTION 012**

Refer generally to Exh. PG&E-17 at 7-32 to 7-42, where PG&E describes many benefits to the general public associated with PG&E’s hydro facility investments, including CAISO grid support and balancing, local area reliability, reliability during Public Safety Power Shutoff events, voltage support, black start capability, fulfillment of water rights and downstream water deliveries, environmental habitat for fish and other species, recreational uses, public safety, and water for fire protection and wildfire response:

- a. Is PG&E able to quantify any of these benefits? If so, please do so and provide PG&E’s supporting workpapers.
- b. Confirm or deny: CCA-owned generation resources can also provide these kinds of public benefits to both bundled and unbundled customers. If deny, please explain.
- c. Confirm or deny: CCAs do not recover costs associated with any of these kinds of public benefits from bundled customers. If deny, please explain.

**ANSWER 012**

- a. PG&E receives ancillary service revenue for CAISO grid support and balancing, and those revenues are based on CAISO tariffed rates.

For the remaining benefits, many are unquantifiable since the counterfactual negative outcome of doing nothing is not an option. (e.g., fulfillment of water rights and downstream water deliveries, environmental habitat for fish and other species, recreation uses, public safety, and water for fire protection and wildfire response:

PG&E’s request in this 2027 GRC application of the cost to maintain and operate its hydro portfolio in alignment with its FERC license terms and conditions may be the best quantification of these benefits albeit, certain environmental and safety externalities (e.g., clean water and protection of habitat for fish and other species, water for fire protection, and dam safety) are likely not fully quantified directly in PG&E’s hydro revenue requirement request.

- b. Neither. PG&E does not have detailed information regarding the composition of the CCA generation portfolio or the CCA-owned generation facilities to know whether

any CCA facilities have similar or comparable public benefits, or how many of the CCA generation facilities provide grid support and balancing service to the CAISO or voltage support, and black start capability.

c. Confirm.

**PACIFIC GAS AND ELECTRIC COMPANY  
2027 General Rate Case Phase I  
Application 25-05-009  
Data Response**

<b>PG&amp;E Data Request No.:</b>	CalCCA_018-Q013
<b>PG&amp;E File Name:</b>	GRC-2027-PhI_DR_CalCCA_018-Q013
<b>Request Date:</b>	April 7, 2026
<b>Requester DR No.:</b>	018
<b>Requesting Party:</b>	California Community Choice Association
<b>Requester:</b>	Julia Kantor
<b>Date Sent:</b>	April 21, 2026
<b>PG&amp;E Witness(es):</b>	Donna Barry – Energy Policy and Procurement

**QUESTION 013**

Refer generally to Exh. PG&E-17 at 7-32 to 7-42, where PG&E describes many benefits to the general public associated with PG&E’s hydro facility investments:

- a. Confirm or deny: the purpose of the PCIA and the Commission’s vintaging regime is to ensure that when customers depart bundled service, they remain responsible for costs previously incurred on their behalf. If deny, please explain.
- b. Confirm or deny: the PCIA is used to recover costs associated with public benefits of UOG resources from unbundled customers. Please explain.
- c. Confirm or deny: in the current vintaging framework adopted by the Commission, utilities treat all new generation resources as generation commitments made on behalf of the utility’s current bundled load as of the year the contract is executed or the utility obtains Commission approval for construction. If deny, please explain.

**ANSWER 013**

- a. Deny. The phrasing in the question is close, but not quite right. The purpose of the PCIA was fully litigated in D.18-10-019 and pages 5 – 7 of that decision provides comprehensive overview of the statutory history of the PCIA as it pertains to CCA formation, which has its foundation in multiple statutes implemented between 2002 and 2015. An excerpt of that overview is shown below:

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 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.<sup>1</sup>

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 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.<sup>2</sup> Most recently, in 2015, SB 350 added Sections 365.2<sup>3</sup> and 366.3<sup>4</sup> 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.<sup>5</sup>

- b. Deny. Unbundled customers pay above market costs of the resources, which could include a portion of public benefits cost.
- c. Confirm.

---

<sup>1</sup> D.04-12-046 at 29.

<sup>2</sup> Stats. 2011, ch. 599 (amending Pub. Util. Code § 366.2)

<sup>3</sup> 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.

<sup>4</sup> 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.

<sup>5</sup>

**PACIFIC GAS AND ELECTRIC COMPANY  
2027 General Rate Case Phase I  
Application 25-05-009  
Data Response**

<b>PG&amp;E Data Request No.:</b>	CalCCA_018-Q014
<b>PG&amp;E File Name:</b>	GRC-2027-PhI_DR_CalCCA_018-Q014
<b>Request Date:</b>	April 7, 2026
<b>Requester DR No.:</b>	018
<b>Requesting Party:</b>	California Community Choice Association
<b>Requester:</b>	Julia Kantor
<b>Date Sent:</b>	April 21, 2026
<b>PG&amp;E Witness(es):</b>	Rebecca Doidge – Generation

**QUESTION 014**

Refer to Exh. PG&E-17 at 7-39:21 to 7-40:6, where PG&E states that the FERC relicensing applications have not been approved and the exact term for new licenses is unknown:

- a. Confirm or deny: approval to continue operation of a hydro facility at the end of a license term occurs via a relicensing application before the FERC. If deny, please explain.
- b. Confirm or deny: approval to continue operation of a hydro facility at the end of a license term cannot be granted by the Commission in a GRC. If deny, please explain.
- c. Confirm or deny: aside from the Commission’s jurisdiction over the decision of whether to approve or deny PG&E’s requested revenue requirement associated with these hydro assets, there are no alternative procedural mechanisms through which the Commission will have the opportunity to review and either approve or disapprove of PG&E’s hydro license extension requests. If deny, please explain.

**ANSWER 014**

- a. Neither. A relicensing application itself does not constitute approval to continue operation of a hydro facility. Continued operation may be authorized through a FERC order issuing a new license or through a FERC notice authorizing continued operation.
- b. Confirm.
- c. The Federal Power Act does not authorize States to issue hydro licenses. Section 19 of the FPA, 16 U.S.C. § 812, reserves for States authority over services, rates and charges. State Commissions may participate in any relicensing proceeding at FERC.

**PACIFIC GAS AND ELECTRIC COMPANY**  
**2027 General Rate Case Phase I**  
**Application 25-05-009**  
**Data Response**

<b>PG&amp;E Data Request No.:</b>	CalCCA_018-Q015
<b>PG&amp;E File Name:</b>	GRC-2027-PhI_DR_CalCCA_018-Q015
<b>Request Date:</b>	April 7, 2026
<b>Requester DR No.:</b>	018
<b>Requesting Party:</b>	California Community Choice Association
<b>Requester:</b>	Julia Kantor
<b>Date Sent:</b>	April 21, 2026
<b>PG&amp;E Witness(es):</b>	Donna Barry – Energy Policy and Procurement, Rebecca Doidge – Generation

**QUESTION 015**

Refer to Exh. PG&E-17 at 7-34:9-14, where PG&E recommends that when re-vintaging is considered, decommissioning costs be separated from the going forward authorized revenue requirement as a separate revenue requirement that remains eligible for recovery from all customers that benefited historically from the resource investment:

- a. Does PG&E currently recover decommissioning costs for its hydro assets through a separate balancing account? Please explain.
- b. Would any changes to PG&E’s current rate recovery procedures for hydro decommissioning costs be necessary to implement PG&E’s suggestion here regarding decommissioning costs? If so, please explain those changes in detail.

**ANSWER 015**

- a. No, there is no separate balancing account for decommissioning costs. See Exhibit (PG&E-10), Chapter 8, Section F for a description of the annual decommissioning expense.
- b. A revenue requirement for decommissioning costs associated with the re-vintaged resources would need to be established as a separate revenue requirement. PG&E has not developed any additional implementation details of this proposal.