Decision **PROPOSED DECISION OF ALJ CHANG** (**Mailed 10/31/2025**)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company to Recover in Customer Rates the Costs to Support Extended Operation of Diablo Canyon Power Plant from January 1 through December 31, 2026, and for Approval of Planned Expenditure of 2026Volumetric Performance Fees. (U39E.)	Application 25-03-015

DECISION ON PACIFIC GAS AND ELECTRIC COMPANY'S REVENUE REQUIREMENT TO SUPPORT EXTENDED OPERATION OF DIABLO CANYON POWER PLANT AND 2026 VOLUMETRIC PERFORMANCE FEES PROPOSAL

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DECISION ON PACIFIC GAS AND ELECTRIC COMPANY'S REVENUE REQUIREMENT TO SUPPORT EXTENDED OPERATION OF DIABLO CANYON POWER PLAN AND 2026 VOLUMETRIC PERFORMANCE FEES PROPOSAL

Summary

This decision approves Pacific Gas and Electric Company's (PG&E's) 2026 Diablo Canyon Power Plant extended operations revenue requirement of $382.233 million. The revenue requirement is allocated to PG&E, Southern California Edison Company, and San Diego Gas & Electric Company using the allocation factors 44.19 percent, 45.86 percent, and 9.95 percent, respectively.

This proceeding is closed.

1. Regulatory Background

Senate Bill (SB) 846 (Dodd, 2022)[1] allows for the potential extension of operations at Diablo Canyon Power Plant (DCPP or DC) beyond the current federal license retirement dates, (2024 for Unit 1 and 2025 for Unit 2), up to five additional years, under specified conditions.

Pursuant to SB 846, Decision (D.) 23-12-036 directs and authorizes extended operations at DCPP until October 31, 2029 (Unit 1) and October 31, 2030 (Unit 2). The authorization in D.23-12-036 is subject to the following conditions: (1) the United States Nuclear Regulatory Commission (NRC) continues to authorize DCPP operations; (2) the $1.4 billion loan agreement authorized by SB 846 is not terminated; and (3) the Commission does not make a

[1] SB 846 (Dodd, 2021-2022 Reg. Sess.) Diablo Canyon powerplant: extension of operations, codified as Public Resources (Pub. Res.) Code Sections 25233, 25233.2, 25302.7, 255548, and 25548.1 7; Public Utilities (Pub. Util.) Code Sections 454.52, 454.53, 712.1, and 712.8; and Water Code Section 13193.5.

future determination that DCPP extended operations are imprudent or unreasonable.[2]

Further, D.23-12-036 allocates the costs and benefits of extended DCPP operations among all load-serving entities (LSEs) subject to the Commission's jurisdiction; creates a new non-bypassable charge (NBC) and associated processes to collect DCPP extended operations costs; and provides further direction on the use of surplus performance-based fees. In D.23-12-036, the Commission also establishes an application process, similar to the annual Energy Resource Recovery Account (ERRA) proceedings, to review and authorize forecasted DCPP extended operations costs, with subsequent true up to actual costs and market revenues for the prior calendar year.[3]

D.23-12-036 directed that the annual DCPP proceeding should:

1. Determine the allocation of costs and benefits of DCPP extended operations among the large electrical corporations' service areas; and
2. Utilize a process that mirrors the Cost Allocation Mechanism (CAM) process to determine the price of the volumetric NBC to be charged by each of the large electrical corporations. Energy Division should utilize the CAM process to determine the allocation of Resource Adequacy (RA) benefits to Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E)

[2] SB 846 (Dodd, 2021-2022 Reg. Sess.) Diablo Canyon powerplant: extension of operations, codified as Public Resources (Pub. Res.) Code Sections 25233, 25233.2, 25302.7, 255548, and 25548.1 7; Public Utilities (Pub. Util.) Code Sections 454.52, 454.53, 712.1, and 712.8; and Water Code Section 13193.5.

[3] D.23-12-036 at Ordering Paragraph (OP) 1.

> and among the load-serving entities (LSEs) in each large electrical corporation's territory, and should endeavor to provide all LSEs with allocations of DCPP's RA benefits for the upcoming compliance year sufficiently in advance of the October 31 year-ahead RA compliance filing deadline.[4]

D.24-12-033 approved PG&E's 2024 DCPP extended operations revenue requirement of $722.6 million and, among other requirements, ordered PG&E to explain in detail why it did not seek government funding for extended operation costs in excess of $1 million.

D.25-06-002 resolved several pending DCPP issues, including requiring PG&E to explain its alignment with the principle of reducing upward pressure on rates in its spending plan submittals, starting with the 2026 Volumetric Performance Fee (VPF) spending plan.[5]

D.25-06-049 adopted changes to the methodology for calculating RA Market Price Benchmark (MPB) values.

2. Procedural Background

In compliance with D.23-12-036, on March 28, 2025, PG&E filed the *Application of the Pacific Gas & Electric Company (U39 E) to Recover in Customer Rates the Costs to Support Extended Operation of DCPP from January through December 31, 2026 and for Approval of Planned Expenditure of 2026 Volumetric Performance Fees* (Application) and served associated testimony.

On April 24, 2025, Resolution ALJ 176-3652 preliminarily determined that this proceeding was categorized as ratesetting.

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[4] D.23-12-036 at 104 and OP 9.

[5] D.25-06-002 at 17.

On April 28, 2025, a protest was filed by CAlifornians for Renewable Energy, Inc. (CARE). On April 30, 2025, protests were filed by San Luis Obispo Mothers for Peace (SLOMP) and The Utility Reform Network (TURN). On May 1, 2025, protests were filed by the Alliance for Nuclear Responsibility (A4NR), California Community Choice Association (CalCCA), Energy Producers and Users Coalition (EPUC), and the Public Advocates Office at the California Public Utilities Commission (Cal Advocates). On May 1, 2025, responses were filed by SCE, SDG&E, and the Coalition of California Utility Employees (CUE). Californians for Green Nuclear Power (CGNP), Women's Energy Matters (WEM), and Small Business Utility Advocates (SBUA) were granted party status in response to their motions filed on May 8, 2025, May 27, 2025, and May 30, 2025, respectively.

On May 12, 2025, PG&E filed a reply to the protests and responses.

A prehearing conference was held on May 30, 2025, to address the issues of law and fact, determine the need for hearing, set the schedule for resolving the matter, and address other matters as necessary. On July 2, 2025, the assigned Commissioner issued a Scoping Memo and Ruling (Scoping Memo).

PG&E submitted amended testimony on July 8, 2025.

The parties to this proceeding submitted testimony on July 24, 2025, followed by the submission of concurrent rebuttal testimony on August 15, 2025.

The parties filed their Joint Report of Meet and Confer and preliminary exhibit and witness list on August 27, 2025 and participated in evidentiary hearings on September 9 and 10, 2025.

The Administrative Law Judge (ALJ) assigned to this proceeding issued a ruling on August 29, 2025 ordering PG&E to submit a calculation of and workpapers for the 2026 fixed management fees using the escalation factor methodology authorized in D.24-12-033 by no later than September 8, 2025. PG&E filed its response to the ruling on September 8, 2025.

A subsequent ALJ Ruling was issued on September 25, 2025 ordering PG&E to provide more detail about how it calculated the 2026 fixed management fee using the escalation factor methodology authorized in D.24-12-003 and the data it used to calculate that 2026 fixed management fee as well as its reasons for proposing a new methodology for calculating the 2026 fixed management fee compared to the methodology authorized in D.24-12-033. The Ruling ordered PG&E to respond to the Ruling on October 8, 2025. PG&E served its testimony in response to the Ruling on October 8, 2025.

A subsequent ALJ Ruling was issued on October 3, 2025 allowing parties to serve additional testimony by October 20, 2025 directly and solely in response to PG&E's testimony of October 8, 2025 responding to the September 25, 2025 ALJ Ruling ordering PG&E to provide more detail about how it calculated the 2026 fixed management fee using the escalation factor methodology authorized in D.24-12-033. The ruling also allowed PG&E to serve reply testimony by October 27, 2025 solely in response to the October 20, 2025 intervenor testimony. Party comments were allowed by October 20, 2025 in response to the market benchmark update calculations.

Opening briefs were filed by A4NR, Cal Advocates, CARE, CalCCA, CGNP, CUE, EPUC, PG&E, SBUA, SLO, WEM, and TURN on October 1, 2025, and reply briefs were filed by A4NR, CalCCA, CGNP, CUE, EPUC, PG&E, SBUA, SCE, TURN, and WEM on October 22, 2025. CARE filed a reply brief on October 23, 2025.

In accordance with the Scoping Memo, PG&E updated its prepared testimony on October 8, 2025, to include any updated forecast and recorded Diablo Canyon Extended Operations Balancing Account (DCEOBA) balances (Fall Update). Comments to the update were filed by A4NR, CalCCA, TURN, WEM, and CGNP on October 20, 2025, and reply comments were filed by PG&E on October 27, 2025.

Cal Advocates, TURN, and EPUC served additional testimony on October 20, 2025 on PG&E's calculation of the 2026 fixed management fee using the methodology authorized in D.24-12-033. PG&E served reply testimony on October 27, 2025. The assigned ALJ issued a ruling marking and identifying, and admitting the public and confidential versions of updated testimony on October 30, 2025.

2.1. Submission Date

This matter was submitted on October 30, 2025, upon the issuance of ALJ Rulings marking and identifying, and admitting the public and confidential versions of updated testimony and workpapers into the record of this proceeding.

3. PG&E's Revenue Requirement Request with the Fall Update

PG&E filed its application for Commission review and approval of its forecasted costs covering the period starting from January 1 through December 31, 2026 (the Record Period) to support DCPP extended operations.

These forecasted costs will be reflected in statewide rates starting on January 1, 2026.

Consistent with the Commission's directives in D.23-12-036, PG&E's application includes: (1) a forecast of costs of extended operations, (2) a forecast of market revenues for DCPP for the Record Period, and (3) proposals for spending the VPF collected in accordance with California Public Utilities Code (Pub. Util. Code) Section 712.8(f)(5). PG&E has also proposed an escalation factor for its fixed management fees utilizing the 2026 cumulative Consumer Price Index - All Urban escalation factor[6] and a Diablo Canyon NBC applicable to all Commission jurisdictional customers based on the forecasted net costs.[7]

PG&E served its Fall Update on October 8, 2025. PG&E's Fall Update includes updated market and generation production information, and updated allocation of the statewide 2026 DC NBC applicable to the investor-owned utilities (IOUs). These updates are based on updates to the Energy Index and RA MPBs issued by the Commission's Energy Division on October 1, 2025.[8]

[6] Exhibit (Ex.) PG&E-01 at 5-4.

[7] Ex. PG&E-01 at Chapter 10.

[8] MPB Calculations at 1.

In the Fall Update, PG&E reports that its forecast of operations and maintenance (O&M) cost presented in its Opening Prepared Testimony, as corrected in the July 8, 2025 errata and supplemental testimony, remains unchanged. Due to improvements in tunnel cleaning efficiency, PG&E increased the generation production forecast, which in turn increases the VPF revenue forecast and the generation revenue forecast. As a result of the updates, for the Record Period, PG&E estimates $1,208.1 million for DCPP costs, statutory fees, and substitution capacity expenses, with an offsetting $842.7 million of California Independent System Operator (CAISO) net forecasted market revenue and an $11.4 million cost for DCEOBA amortization, for a net revenue requirement of $382.233 million.[9]

If authorized as proposed, the requested revenue requirement would be allocated to the IOUs as follows: (1) PG&E, $238.6 million; (2) SCE, $113.3 million; and (3) SDG&E, $30.6 million.[10]

PG&E estimates that the requested revenue requirement, if approved, would result in a system average bundled service rate decrease by approximately 0.5 percent to approximately 34.6 cents per kWh when compared to the present system average bundled service rate of approximately 34.8 cents per kWh.[11] The system average rate for Direct Access (DA) and Community Choice Aggregation (CCA) customers would decrease by approximately 0.8 percent to 19.6 cents per kWh, when compared to the present system average

[9] Ex. PG&E-04 Table 9-4.

[10] Ex. PG&E-04 Table 10-4.

[11] Ex. PG&E-04 at 21.

rate for DA and CCA customers of 19.8 cents per kWh.[12] Similarly, SCE's system average bundled service rate would decrease by 0.7 percent to 29.9 cents per kWh.[13] SDG&E's system average bundled service rate would decrease by 0.4 percent to 35 cents per kWh.[14]

4. Issues Before the Commission

Pursuant to the Scoping Memo, dated July 2, 2025, the issues to be determined in this proceeding are as follows:

1. Whether PG&E's forecast cost of operations and requested revenue requirement of $410 million over the Record Period for DCPP is reasonable, including the following forecasts and their underlying financial assumptions and calculations, subject to PG&E updating these forecasts in the Fall Update;
    a. Operations and maintenance costs (including expenses, project costs, and statutory costs and fees, as well as associated escalations);
    b. Charges for the liquidated damages account pursuant to Pub. Util. Code Section 712.8(g);
    c. RA substitution capacity forecast and true-up costs, including any updates from the results of Rulemaking (R.) 25-02-005, or unless otherwise directed by the Commission;
    d. Operating expenses that would be amortized through 2030 (e.g., nuclear fuel procurement);
    e. Netting of CAISO revenues for the period from January 1 to December 31, 2026.

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[12] Ex. PG&E-04 at 21.

[13] Ex. PG&E-04 Table 10-9.

[14] Ex. PG&E-04 Table 10-12.

2. Whether the calculation of the non-bypassable charge and rate proposals by PG&E, SCE, and SDG&E comply with D.23-12-036 and should be approved.
3. Whether PG&E's proposed modification to the Department of Energy Litigation Balancing Account (DOELBA) preliminary statement to be implemented in a Tier 1 advice letter within 60 days following the issuance of the decision is reasonable.
4. Whether the Market Price Benchmark is the right method for calculating RA substitution capacity and true-up costs for DCPP or whether an alternative method is more appropriate.
5. Whether PG&E's proposed VPF spending plan for the January 1 to December 31, 2026 period complies with Pub. Util. Code Section 712.8(s) and all Commission requirements and should be approved.
6. Whether PG&E's testimony satisfies all the regulatory requirements set forth, including D.23-12-036 and D.24-12-033.

The July 2, 2025 Scoping Memo identified the following issues as out of scope:

1. Whether PG&E's proposed modified regulatory process for PG&E to utilize a Tier 3 advice letter for reporting on the amount of VPFs, explaining how the funds were spent, and proposing a plan for prioritizing the uses of such funds pursuant to Pub. Util. Code Sections 712.8(f)(5) and 712.8(s)(1), is reasonable and should be approved.
2. Whether the Commission should review VPF spending plans beyond evaluating whether they comply with Pub. Util. Code Section 712.8(s) requirements and procedural requirements from D.23-12-036.

3. Whether the Commission should review historical DCPP costs.
4. Whether PG&E's extended operations of DCPP are prudent and cost-effective.
5. Whether the federal and state income tax gross-up of fixed management fees should be included in PG&E's forecast cost of operations and requested revenue requirement for DCPP.

The Commission reiterates that, in D.23-12-036, the Commission concluded that it will not revisit issues concerning the electric system reliability need for DCPP.[15] Ongoing long-term system reliability needs are already considered and addressed through the Commission's Integrated Resource Planning proceeding. Hence, they are out of scope for this proceeding.

5. Burden of Proof and Evidentiary Standard

Pub. Util. Code Section 451 requires that "[a]ll charges demanded or received by any public utility…shall be just and reasonable." As the applicant, PG&E bears the burden of establishing reasonableness of all issues within the scope of this proceeding as listed in Section 4 of this decision.

The Commission has held that the standard of proof the applicant must meet in rate cases is that of a preponderance of the evidence.[16] Preponderance of the evidence is usually defined "in terms of probability of truth, *e.g.* 'such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth.'"[17]

[15] D.23-12-036 at 64.

[16] D.19-05-020 at 7; D.15-11-021 at 8-9; D.14-08-032 at 17.

[17] D.08-12-058 at 19, citing Witkin, Calif. Evidence, 4th Edition, Vol. 1 at 184.

6. PG&E's Forecasted Cost and Requested Revenue Requirement

The Commission approves PG&E's 2025 DCPP extended operations revenue requirement of $382.233 million. Forecasted cost categories and modifications are discussed in Sections 6.1 through 6.5.

6.1. Operations and Maintenance Costs

The Commission approves PG&E's request to recover $563.934 million in O&M costs for the period January 1 to December 31, 2026.

6.1.1. PG&E's Forecasted O&M Costs

In its Application with the Fall Update, PG&E requests the Commission adopt its forecast for total extended operations and maintenance expense, excluding nuclear fuel procurement) of $563.934 million for the period January 1 to December 31, 2026.[18] PG&E's forecasted O&M expense are comprised of nine Major Work Categories (MWC) – manage environmental operation, manage DCPP business, operate DCPP plant, loss prevention, maintain DCPP plant assets, enhance DCPP personnel performance, maintain DCPP plant configuration, provide nuclear support, and manage balancing account processes.[19]

In D.23-12-036, the Commission directed that "costs associated with Diablo Canyon Independent Safety Commission (DCISC) recommendations or NRC's conditions of license renewal shall only be included to the extent there are actual recommendations and conditions from the DCISC and NRC.[20] PG&E reports that

[18] PG&E Opening Brief at 8-9; Exhibit PG&E-01 at 2-2.

[19] Ex. PG&E-01 at 2-15 to 2-23.

[20] D.23-12-036 at 60.

there are no actual or known forecastable costs for NRC license renewal conditions or any DCISC recommendations during the record period.[21]

In its Application, PG&E explains that similar to PG&E's General Rate Case (GRC) cost structure, the forecasted costs are presented in the MWC level.[22] An overview of PG&E's O&M cost forecast is shown below in Table 1.

Table 1: PG&E's O&M Cost Forecast (thousands of nominal dollars)

Cost Type	2023 Recorded	2024 Forecast	2025 Forecast	2026 Forecast	Total Period Forecast
O&M Expense	N/A	$6,121	$298,484	$449,286	$753,891
Project Expense	N/A	$2,197	$63,030	$60,496	$125,723
Fuel Administration	N/A	N/A	N/A	$1,092	$1,092
Retention Program Expense	$17,025	$55,277	$56,210	$53,061	$181,573
Total O&M Expense (excluding nuclear fuel procurement)	$17,025	$63,596	$417,724	$563,934	$1,062,279

PG&E states that the first component, the base O&M expense, reflects the incremental costs in excess of the Department of Water Resources (DWR) loan for the period January 1 through December 31, 2026.[23] The O&M expense covers

[21] Ex. PG&E-01 at 2-2.

[22] A.25-03-015 at 19.

[23] Ex. PG&E-01 at 2-2.

labor costs and non-labor costs (materials, contracts, and other costs).[24] No party has challenged PG&E's forecasted O&M expenses.

Regarding the second component, the project expense, PG&E provides the following information:

> All of the project expenses included in PG&E's forecast comply with the Commission-adopted framework for project expenses as extended operations costs to be recorded to DCEOBA and recovered in customer rates: a project that is not required as part of the NRC license renewal process or as a condition of PG&E's license renewal application and "(1) [is] expected to be placed in service on or after January 1, 2027 and/or (2) the project scoping, design, engineering, procurement and implementation efforts generally begin after the original Unit 1 license expiration date of November 2, 2024."

As discussed in the following section, CARE, WEM, A4NR, TURN, EPUC, and SBUA challenge several aspects of this assertion by PG&E.

The third component, the retention program expense, reflects the proposed DCPP retention program established to retain the personnel necessary for safe and reliable operation of the plant through the Record Period. In D.24-09-002, the Commission approved an uncontested settlement agreement in which the settling parties agreed that a reasonable total cost estimate for the employee retention program for September 1, 2023, through November 1, 2030 is $390 million. In total, $53.061 million of $390 million is included in the O&M expense and will be recovered during the Record Period. The forecasted 2026 amount reflects adjustments to the number of DCPP personnel eligible to receive

[24] Ex. PG&E-01 at 2-15.

retention payments.[25] No party has challenged PG&E's forecasted employee retention costs.

6.1.2. Distinction Between Preparatory/Transition Costs and Extended Operation Costs

Similar to the discussion in A.24-03-018, several parties in this proceeding dispute PG&E's forecasted O&M cost components and argue that these cost components support activities in preparation or transition to operation, and therefore, they should not be recovered from ratepayers and should instead be recovered through government funding. For example, A4NR questions the ineligibility of the O&M Project Expense for recovery under PG&E's executed agreements with DWR or the U.S. Department of Energy (DOE) Civil Nuclear Credit program. In particular, A4NR disputes the inclusion in the current application of $55,461,049 in forecast project costs, stating that $42,787,244 is for projects identified by PG&E's Preventative Maintenance Optimization (PMO++) Review and $12,673,805 is for dry cask storage already funded by Senate Bill 846 and Assembly Bill 180 in 2022.[26] A4NR points to PG&E's use of a date-based framework for distinguishing between transition and extended operational costs, as approved in D.24-12-033, and argues that "PG&E data responses in this proceeding have demonstrated the easy manipulability of using arbitrary dates, rather than the statute's focus on motivating purpose, to distinguish between 'transitional or preparatory costs' recorded in Diablo Canyon Transition and Relicensing Memorandum Account (DCTRMA) and 'extended operations costs'

[25] Ex. PG&E-01 at 2-30.

[26] A4NR Opening Brief at 2.

recorded in DCEOBA."[27] [28] EPUC cites testimony by TURN and A4NR to argue that "PG&E's two-pronged proposal therefore seeks to enable the company to shift transitional or preparatory costs to the ratepayers, in direct contradiction to the Commission's previous rulings."[29]

PG&E does not agree with A4NR's assertion and cites D.24-12-033's finding that PG&E's time-based framework for differentiating between projects implemented in preparation for extended operations and projects to support extended operations to be "workable and reasonable."[30] Additionally, PG&E argues that "[t]he fact that most of these projects needed to support extended operations were identified between December 2022 and December 2023 through the PMO++ process does not transform the projects, which are necessary to implement safe and reliable operations through 2030, into projects necessary to prepare for extended operations as A4NR suggests."[31]

Similarly, CARE argues that PG&E is attempting to recover $112,767,000 in costs for 17 projects that were identified by the DCISC in 2024.[32] CARE states: "The truth is the DCISC has made many recommendations which PG&E is now seeking ratepayer funding for over the next four years. These costs are also identified by the DWR loan as transitional costs that should be funded by the

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[27] D.24-12-033 at 17-18.

[28] Ex. ARNR-01 at 9-10.

[29] EPUC Opening Brief at 12.

[30] PG&E Opening Brief at 10.

[31] PG&E Opening Brief at 11.

[32] Ex. CARE-01 at 11-12.

1.4 billion-dollar State of California loan not by ratepayers as PG&E proposes in its application. The commission should not allow PG&E to continue to shift transition projects costs on to ratepayers."[33] PG&E responds that CARE's argument is a "mischaracterization of the DCISC's 34th Annual Report" and points again to the time-based framework that D.24-12-033 found to be "reasonable and workable" to distinguish projects and costs deemed preparatory that can be recovered from government funding and costs for extended operations that are recoverable from customers.[34]

Additionally, CARE argues that PG&E must include higher property tax expenses for DCPP to account for "the increase in property taxes that will be assessed on the expensive upgrades that have been installed on DCPP to support extended operations."[35] PG&E responds in its Opening Brief that "[b]ecause DCPP extended operations costs are treated as operating expenses and do not contribute to PG&E's rate base, PG&E does not forecast any incremental property tax for 2026."[36] CARE also argues that PG&E should not be allowed to recover $130,660 in license renewal costs, $97,054 in DCPP incremental overtime and temporary additional labor related to license renewal, and $33,606 in license renewal costs associated with the provider cost center from 2024 to 2030. [37] CARE cites Pub. Util. Code Section 712.8(c)(1)(C) stating "[t]he commission shall not

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[33] Ex. CARE-01 at 10.

[34] PG&E Opening Brief at 12-13.

[35] Ex. CARE-01 at 5.

[36] PG&E Opening Brief at 28.

[37] Ex. CARE-01 at 5-6.

allow the recovery from ratepayers of costs incurred by the operator to prepare for, seek, or receive any extended license to operate by the United States Nuclear Regulatory Commission."[38] CARE's argument erroneously cites the license renewal amount associated with the provider cost center, which actually totals 34,172 hours.[39]

In rebuttal testimony, PG&E responds that the $97,054 cited by CARE is related to extended operations activities. PG&E asserts that employees reporting to the License Renewal Budget Center perform diverse responsibilities including license renewal applications and extended operations.[40] PG&E states that the $97,054 amount is specifically for extended operations overtime hours related to the 1R26 outage and that the License Renewal Budget Center should be retired by the 2027 DCPP cost recovery filing.[41] PG&E also states that the $33,606 in license renewal Provider Cost Center Productive Hours cited by CARE actually refers to 34,172 hours in license renewal costs associated with its provider cost center that are part of the calculation to determine a standard rate for each center.[42] PG&E states: "Although PG&E's request in this proceeding excludes license renewal cost recovery, for developing a standard rate for each PCC across the plant, the license renewal hours must be included as part of the standard rate estimating calculation. Importantly, only costs from employees in the License

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[38] Ex. CARE-01 at 5-6.

[39] Ex. PG&E-01A-WP at WP 2-5.

[40] Ex. PG&E-03 at 2-2.

[41] Ex. PG&E-03 at 2-2.

[42] Ex. PG&E-03 at 2-3.

Renewal (Provider Cost Center) who are supporting extended operations and charging to a DCEOBA order are included for recovery in this proceeding."[43]

WEM cites arguments made by CARE and A4NR about projects identified by the PMO++ and the DCISC reports, writing that "[t]he record contains evidence that PG&E's 2026 Diablo Canyon revenue request includes costs which, without a doubt, should be paid through government funding streams, but PG&E has instead tracked them to the DCEOBA, labeling them as operating expenses to be paid by ratepayers."[44] Additionally, WEM argues that the DWR review process established by SB 846 only reviews Diablo Canyon expenses record in the DCTRMA and does not examine the costs PG&E has tracked to the DCEOBA to see if they instead should be recorded in the DCTRMA.[45] WEM also argues that PG&E is straying from the date-based method for distinguishing between transition and operational costs approved in D.24-12-033 by stating in A.25-03-015 testimony by PG&E witness Brian Ketelsen that "[p]roject cost forecast to be incurred earlier than November 3, 2024, not funded by reserves from the 2023 GRC, and forecast to be complete and in service earlier than December 31, 2026, are generally tracked to the Diablo Canyon Transition Memorandum Account and funded through the DWR Loan." [46, 47] WEM points out that D.24-12-033 had defined extended operations costs as "project scoping,

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[43] Ex. PG&E-03 at 2-3.

[44] WEM Opening Brief at 3.

[45] WEM Opening Brief at 9.

[46] Ex. PAO-01 at 2-25.

[47] WEM Reply Brief at 2-3.

design, engineering, procurement and implementation efforts [that] generally begin after the original Unit 1 license expiration date of November 2, 2024."[48] WEM then states about the use of the verb "incurred" in Mr. Ketelsen's testimony: "This is entirely new. Ketelsen has morphed the Commission's [D.24-12-033] language into a new framework that would allow PG&E to illegally shift transition cost onto ratepayers in this proceeding."[49]

Finally, SBUA argues that PG&E has not offered enough information to determine whether the proposed O&M costs overlap with expenses using DWR funding.[50] SBUA points to Attachment G in A4NR-01 including a declaration from Mr. Ketelsen, PG&E's director of nuclear business and technical services, in *Friends of the Earth vs. Jennifer Granholm*, and a spreadsheet that shows the DWR loan funds were used for license renewal, dry cask storage, upgrade projects, programs, operational enhancements, fuel, and performance based disbursements.[51] SBUA states: "It remains unclear how the excess $410 million (those funds beyond monies secure through the federal DOE grant) are clearly distinct, necessary, and justified."[52]

TURN also cites the declaration made by Mr. Ketelsen in *Friends of the Earth vs. Jennifer Granholm* and the attached spreadsheet, Transition and License Renewal Expenditure Summary (TLRES), showing $1.487 billion in transition

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48 WEM Reply Brief at 2-3.

49 WEM Reply Brief at 2-3.

50 Ex. SBUA-01 at 2.

51 Ex. A4NR-01 Attachment G.

52 SBUA Opening Brief at 4.

and license renewal spending forecast through 2026, which is $157 million more than the $1.4 billion allocated in the DWR loan after accounting for administrative costs that DWR is authorized to retain.[53] TURN also points to PG&E's refusal to respond to TURN's data request seeking more detail about the spending listed in the TLRES, with PG&E stating in its response: "PG&E objects [sic] this data request on grounds that the information requested is outside of the scope of this proceeding. Subject to that objection, PG&E responds that its record period forecast for costs to be recovered through the DCEOBA is presented in prepared testimony Chapter 2."[54] Overall, TURN argues that PG&E has not provided information about all DCPP costs in A.25-03-015, and in particular any costs recovered through the DWR loan authorized in SB 846.[55] TURN also cites PG&E's refusal to provide information about DCPP costs between 2023-2030, including "all GRC and ERRA costs associated with Diablo Canyon prior to, and during, extended operations." In its response to TURN's data response about DCPP costs between 2023 and 2030, PG&E states it "objects to this request on the grounds that the request for historic information is out of scope for this proceeding. Subject to and without waiving this objection, PG&E responds that there are no DCPP period of extended operations costs in the pending GRC or ERRA proceedings."[56] PG&E does not otherwise respond to TURN's arguments in its Rebuttal Testimony or Opening Brief.

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[53] Ex. TURN-01 at 54.

[54] Ex. TURN-02 Answer 012.

[55] TURN Opening Brief at 10.

[56] Ex. TURN-02 Answer 002.

Upon review of the testimony on this matter, the Commission continues to find that PG&E's approach to distinguishing between transition costs and extended operations costs for the purpose of tracking costs in the DCTRMA for recovery via government funding and recording costs to DCEOBA for recovery in customer rates to be reasonable and consistent with the intent of SB 846 and compliant with Commission decisions.

As described in D.24-12-033, "[t]he distinction between transitional or preparatory costs versus extended operations costs has not been clearly made by the relevant statute. However, PG&E notes, and we agree, that Pub. Util. Code Section 712.8(d) refers to 'O&M expense' as that term is used in traditional cost of service ratemaking and is meant to preclude recovery of additional/incremental costs to those authorized in PG&E's 2023 GRC, which assumed DCPP retirement dates of 2024 and 2025. … Given that all costs of DCPP extended operations must be recovered as O&M expense (i.e., none of the costs can be capitalized or rate-based) any other interpretation of Pub. Util. Code Section 712.8(d) renders moot Pub. Util. Code Sections 712.8(h)(1), (f)(2), (f)(5) and (f)(6)" governing the ability of PG&E to recover reasonable costs from DCPP as well as its ability to operate an employee retention program and receive VPF and Fixed Management Fees.[57]

The Commission finds persuasive PG&E's argument that the identification of DCPP projects in the PMO++ and DCISC reports before November 2, 2024 does not automatically render those projects transition spending that should be recorded in the DCTRMA. In particular, the DCISC report described

[57] D.24-12-033 at 17.

approximately 250 projects identified in the PMO++ program “for consideration of prioritization for implementation during the extension of operations” with the project list “envisioned to be a ‘living document’ that would be used in the future to inform outage planning, maintenance planning, and engineering decisions made during the routine project planning meetings.”[58] The report continues: “The preliminary results called for about 50 projects to be completed within the next three years with about 12 of those 50 to be performed during the upcoming Refueling Outage 1R24 in the fall of 2023.”[59] While CARE’s Opening Brief references the projects identified in the DCISC report as those that should be excluded from A.25-03-015 cost recovery, the report itself identifies those projects as part of “preliminary results” and a “living document.” Through this language, the DCISC report is clear that the projects are identified largely for planning purposes and are subject to modification.

The license renewal costs that CARE highlights appear to be for extended operations, as stated by PG&E in Rebuttal Testimony, and are allowed by Pub. Util. Code Section 712.8(c)(1)(C).

Additionally, in its argument that PG&E is not disclosing all required DCPP costs, TURN cites instructions in D.23-12-036 that PG&E must describe “as part of its 2024 DCPP Extended Operations Cost Forecast Application” “[a]ny government-funded transition costs.”[60] TURN, however, omits in its Opening

[58] Ex. CARE-03 at Section 3.92c.

[59] Ex. CARE-03 at Section 3.92c.

[60] TURN Opening Brief at 10.

Brief that the instruction applied only to the 2024 DCPP application.[61] While such detail would have been helpful in evaluating A.25-03-015, D.23-12-036 did not require PG&E to include that detail in this application. D.23-12-036 does not prohibit PG&E from including detail about government-funded transition costs in future applications.

Finally, TURN, WEM, SBUA, and A4NR raise legitimate concerns that PG&E may be recovering, in this application, overspending on DCPP transition and renewal costs in excess of the $1.4 billion DWR loan, as referenced in the TLRES. In oral arguments, Mr. Ketelsen stated that PG&E was "in the process of a reprioritization to ensure we utilized the full [DWR] amount without going over."[62] While the DWR and CPUC are required to conduct a semiannual true-up to review PG&E's use of DWR loan proceeds, which includes Advice Letter submittals by PG&E summarizing DWR spending; the parties appropriately raise questions as to whether PG&E's reprioritization of transition and renewal funds might be improperly shifting those costs to the current application as funding for DCPP extended operations. In future DCPP cost recovery applications, it is reasonable to require PG&E to disclose whenever any transition and license renewal costs that were part of the amounts included in the TLRES are proposed for recovery in any future DCPP forecast proceedings for DCPP extended operations, along with explanations for why those costs were originally

[61] TURN Opening Brief at 10.

[62] Reporter's Transcript (RT) Page 20: line 23-24.

proposed as transition and license renewal costs and why those costs are now eligible for recovery for extended operations.

Finally, D.24-12-033 found that "[e]ven though PG&E provided a workable framework to distinguish transitional costs from extended operations costs, PG&E failed to provide in its application a detailed explanation why PG&E did not seek government funding, or was otherwise unable to anticipate the need for the investments and activities at the time government funding was being requested. … Therefore, in its next application, PG&E must provide this information as directed by the Commission in D.22-12-005."[63] D.24-12-033 also states: "In its next Application, PG&E must: (1) provide detailed information for all projects with costs more than $1 million; and (2) provide a detailed account of why it did not seek government funding for the costs being requested to be recovered from ratepayers, or was otherwise unable to anticipate the need for the investments and activities at the time government funding was being requested."[64]

PG&E addresses this requirement in Chapter 2 of its Prepared Testimony by stating: "PG&E provides this information in the Projects Summaries in Workpapers Supporting Chapter 2."[65] In the "Projects Summaries for Projects > $1 Million" section of its Corrected Workpapers Supporting Chapter 2, PG&E states for each project: "This project is classified as an extended operations cost recoverable in customer rates through the Diablo Canyon Extended Operations

[63] D.24-12-033 at 18-19.

[64] D.24-12-033 at 23.

[65] Ex. PG&E-01 at 2-26.

Balancing Account because most of the expenditures in 2024 were incurred after November 2, 2024" and "is not a condition of PG&E's License Renewal Application before the U.S. Nuclear Regulatory Commission."[66] PG&E also details the amounts spent before November 2, 2024 on each project as a rationale for not using government funding for the whole project.

6.1.3. Conclusion – O&M Costs

Upon consideration and based on the discussion presented in Section 6 of this decision, the Commission finds that PG&E's forecasted O&M costs comply with the applicable statute and Commission orders, are reasonable, and should be approved.

6.2. Statutory Fees

The Commission approves the following statutory fees authorized by SB 846 and requested by PG&E for the extended operations period of November 3, 2024 through December 31, 2025: (1) $113.997 million in the Fixed Management Fee; (2) $113.283 million in the VPF; and (3) $75 million to be recorded to the liquidated damages subaccount of the DCEOBA.[67]

6.2.1. Fixed Management Fees

The Commission approves PG&E's fixed management fees in the amount of $113.997 million.

SB 846 authorizes PG&E to collect a fixed payment of $50 million per unit per year of extended operations "[i]n lieu of a rate-based return on investment and in acknowledgment of the greater risk of outages in an older plant that the

[66] Ex. PG&E-01A-WP at 2-12 to 2-49.

[67] Ex. PG&E-04 Table 9-4.

operator could be held liable for."[68] The statute also orders that "[t]he amount of the fixed payment shall be adjusted annually by the commission using commission-approved escalation methodologies and adjustment factors."[69] The Commission determined that the Fixed Management Fee, referred to in statute as a "fixed payment," would be recovered from ratepayers of all LSEs through the DC NBC.[70] D.24-12-033 ordered PG&E to use a Fixed Management Fee escalation factor based on electric generation capital costs as proposed by TURN.[71] SB 846 also requires the Commission to approve recovery on a forecast basis "with a subsequent true-up to actual costs and market revenues for the prior calendar year via an expedited Tier 3 advice letter process."[72]

In its prepared testimony for A.25-03-015, PG&E proposes another method to calculate the Fixed Management Fee rather than the methodology ordered in D.24-12-033, resulting in a total forecasted Fixed Management Fee of $113.884 million in 2026.[73] PG&E proposes applying a 2026 Fixed Payment average cumulative escalation rate of 1.1388, which PG&E states is the forecast 2026 cumulative Consumer Price Index-All Urban (CPI-U) escalation factor.[74] PG&E proposes to use 2022 as the base year for its cumulative escalation rate

[68] Pub. Util. Code § 712.8(f)(6).

[69] Pub. Util. Code § 712.8(f)(6).

[70] D.23-12-036 at 67.

[71] D.24-12-033 at 25.

[72] Pub. Util. Code 712.8 (h)(1)

[73] Ex. PG&E-01 at 1-5.

[74] Ex. PG&E-01 at 5-4.

circulation "to properly adjust the Fixed Management Fee to account for the loss in the value of the dollar since 2022."[75] PG&E explains that the "[u]se of CPI-U to escalate the Fixed Management Fee is appropriate because it is a measure of inflation that is widely used across the United States for measuring the change in the value of the dollar."[76] In response to an August 29, 2025 ALJ Ruling, PG&E calculated that using the methodology approved in D.24-12-033 would produce a Fixed Management Fee of $121.3 million for the 2026 record period - $7.416 million higher than the forecast Fixed Management Fee using the escalation method proposed by PG&E in A.25-03-015.[77] In its response to the September 25, 2025 ALJ Ruling regarding the Fixed Management Fee, PG&E further explains that "the capital generation-only escalation rate adopted in D.24-12-033 was deflationary, applying a cumulative escalation factor of .976 for 2024 and .986 for 2025. Applying these factors to a $1 dollar value suggest that 97.6 cents ($1*.976=97.6 cents) in 2024 and 98.6 cents ($1*.986=98.6 cents) in 2025 has the same value/buying power as $1 would in 2022. This is simply not so, as there has been no such deflation in the value of the dollar between 2022—the inflationary base year—and 2024 and 2025, contrary to what the escalation factors adopted in D.24-12-033 18 suggest."[78] PG&E also states that the increase in the Fixed Management Fee calculated with the D.24-12-033 capital costs escalation methodology reflects continued high prices as "since Q3 2023

[75] Ex. PG&E-01 at 5-4.

[76] Ex. PG&E-01 at 5-4.

[77] PG&E September 8, 2025 Response to August 29, 2025 ALJ Ruling.

[78] Ex. PG&E-04 at 4.

shortages have continued in some categories (in particular electrical equipment) and sufficient demand in others (such as machinery)."[79] PG&E also asserts that "the difference between 2018-2021 generation escalation rates between those presented in A.24-03-018 and those presented on September 8 2025, is that the 2018-2021 generation escalation rates captured mid-year escalation rates where they should have captured full year recorded escalation rates."[80]

Several parties challenge PG&E's proposed methodology for calculating Fixed Management Fee escalation rates. TURN states that "allowing PG&E to apply different historical escalators (prior to 2025) would create a substantial disconnect between the 2025 adopted value and the adopted 2026 value, effectively allowing PG&E to circumvent D.24-12-033 and significantly increasing the (Fixed Management Fee) in 2026."[81] TURN also offers its own calculation of the 2026 Fixed Management Fee using the escalation methodology approved in D.24-12-033, the adopted escalators from D.24-12-033 for 2022-2025, the annual escalators from PG&E's current GRC for 2026-2030 for hydroelectric- and fossil-based energy, and the nuclear escalators adopted in D.24-12-033 for all years, forecasting a $99.290 million 2026 Fixed Management Fee.[82] In supplemental testimony filed on October 20, 2025, TURN argues that PG&E should apply the escalation method adopted in D.24-12-033 only on the 2025

[79] Ex. PG&E-04 at 3.

[80] Ex. PG&E-04 at 3.

[81] TURN Opening Brief at 5.

[82] Ex. TURN-01 at 16-17.

Fixed Management Fee value.[83] TURN also offers an alternative method applying the CPI-U-based escalation rate on the 2025 Fixed Management Fee value, which it calculates would produce a 2026 fee of $101.88 million.[84] TURN also questions PG&E's explanation for the difference between the 2018-2021 generation escalation rates presented in A.24-03-018 and those presented in PG&E's September 8, 2025 response to the ALJ ruling requesting PG&E's estimate of the 2026 Fixed Management Fee using the methodology approved in D.24-12-033. In particular, TURN states that PG&E's citing of the previous escalation rate using mid-year estimates compared to whole-year estimates doesn't explain why the annual escalators for nuclear- and hydro-powered electricity generation in 2014 and 2015 didn't change using the whole-year methodology while fossil-fuel-powered generation fluctuated by -56.98 percent in 2014 and 73.2 percent in 2015.[85]

EPUC and Cal Advocates support continuing to use the escalation fee methodology approved in D.24-12-033. EPUC argues that setting 2022 as the base year for the proposed CPI-U-based Fixed Management Fee escalation calculation "reflects changes in the value of the dollar from 2023 and 2024 that should have already been recovered in the prior fixed payment fee the Commission approved."[86] Cal Advocates argues that the CPI-U used in PG&E's proposed 2026 escalation methodology estimates "the relative change in price of a basket of

[83] Ex. TURN-05 at 19-22.

[84] Ex. TURN-05 at 22.

[85] Ex. TURN-05 at 13.

[86] Ex. EPUC-01 at 8.

goods and services from an urban consumer's perspective" whereas "investment items, such as business expenses, are excluded from the CPI-U."[87] Cal Advocates cites the U.S. Bureau of Labor Statistics Handbook of Methods for this definition of the CPI-U.[88] Cal Advocates concludes that "[t]he lack of any connection to investment in generation assets means the CPI-U should not reasonably be used as the cumulative escalation factor for the (Fixed Management Fee)."[89] In supplemental testimony filed October 20, 2025, Cal Advocates suggests using the Producer Price Index (PPI) issued by the U.S. Bureau of Labor Statistics over the S&P Power Planner escalation factor used by PG&E to calculate the Fixed Management Fee using the methodology approved in D.24-12-033 given the "opacity of its calculation and inconsistency with similar publicly available data."[90] Cal Advocates estimates using the PPI to escalate the Fixed Management Fee would produce a 2026 fee of $100.4 million.[91]

PG&E responds in its Opening Brief that "PG&E was not required to use the escalation factor adopted for the years 2024 and 2025 in its forecast of 2026 fixed payments," citing the language in Pub. Util. Code Section 712.8(f)(6)(A).[92] PG&E also cites its September 8, 2025 response to the August 29, 2025 ALJ Ruling finding that escalating the Fixed Management Fee using the methodology

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[87] Cal Advocates Opening Brief at 7.

[88] U.S. Bureau of Labor Statistics Handbook of Methods, Ch. 17, at 1.

[89] Cal Advocates Opening Brief at 7.

[90] Ex. PAO-02 at 3-10.

[91] Ex. PAO-02 at 9.

[92] PG&E Opening Brief at 16.

approved in D.24-12-033 produces a fee that is $7.4 million higher than the fee calculated using the methodology proposed in A.25-03-015.[93] PG&E also states that "[t]he purpose of applying the CPI-U cumulative escalation factor to the Fixed Management Fee is to properly adjust the Fixed Management Fee to account for the loss in the value of the dollar since 2022, the base year for the Fixed Management Fee."[94]

Finally, PG&E responds to Cal Advocates' argument about the applicability of the CPI-U by stating in rebuttal testimony: "(CPI-U) is an annual payment to PG&E, not an expense or capital expenditure by PG&E, instituted by the state of California for the safe and reliable operation of DCPP. CPI-U is an appropriate escalation factor of the Fixed Payment given CPI-U's broad use across the U.S. economy."[95] Finally, PG&E argues that the Fixed Management Fee is not a capital expenditure so it should not be escalated using electricity generation capital escalation rates.[96] PG&E witness Conor Doyle states: "[T]he Fixed Payment is provided as a financial payment to PG&E for its safe and reliable operation of DCPP. During the period of extended operations, there are no capital expenditures incurred at DCPP."[97]

[93] PG&E Opening Brief at 16.

[94] Ex. PG&E-01 at 5-4.

[95] Ex. PG&E-03 at 5-2.

[96] Ex. PG&E-03 at 5-3.

[97] Ex. PG&E-03 at 5-3.

6.2.1.1. Discussion

The Commission finds PG&E's argument persuasive that the Fixed Management Fee should be calculated using the CPI-U rather than the electricity generation capital cost methodology adopted in D.24-12-033. The large fluctuations seen in the yearly electricity generation capital escalation rate forecasts revealed by PG&E's Response to the August 29, 2025 ALJ Ruling point to higher potential volatility in using that measure of the Fixed Management Fee, as opposed to the overall stabler CPI-U measure. PG&E further argues that D.24-12-033 did not specify that the capital escalation rate methodology that it adopted necessarily applied to every DCPP cost recovery application going forward. Additionally, PG&E cites Pub. Util. Code Section 712.8(f)(6)(A) only requiring that "[t]he amount of the fixed payment shall be adjusted annually by the commission using commission-approved escalation methodologies and adjustment factors." It is appropriate to escalate the Fixed Management Fee using 2022 as the base year since Pub. Util. Code Section 712.8(f)(6)(A) orders the Commission to "authorize the operator to recover in rates a fixed payment of fifty million dollars ($50,000,000), in 2022 dollars, for each unit for each year of extended operations." Additionally, using the CPI-based method to escalate the Fixed Management Fee amount approved in D.24-12-033, as TURN suggests, would improperly mix two different escalation methods to calculate the 2026 fee – the electricity general capital cost escalator and the CPI-U. In particular, mixing two different escalation methods would confuse the true-up process for the Fixed Management Fee.

We also find that the CPI-U-based escalation method is more transparent than the electricity generation capital-based escalation rate approved in D.24-12-033 since the CPI-U-based method uses an indicator produced by the U.S. Bureau of Labor Statistics as opposed to the proprietary capital escalation rate calculated by S&P. Finally, as PG&E argues, the Fixed Management Fee is not a business or capital expense, but a statutory fee paid to PG&E "[i]n lieu of a rate-based return on investment and in acknowledgment of the greater risk of outages in an older plant that the operator could be held liable for."[98] While D.24-12-038 found that "DCPP is a generation asset and the purpose of the Fixed Management Fee is to compensate PG&E shareholders for the risks associated with generation assets," the fee itself is a statutory fee and not a capital cost.[99]

For the reasons described above, it is appropriate for PG&E to calculate its 2026 DCPP Fixed Management Fee using the methodology described in its Application. To promote consistency and provide additional clarity in the process, we also direct PG&E to use the CPI methodology in future DCPP forecast applications as well to incrementally escalate the Fixed Management Fee approved in the previous year's DCPP application.

6.2.2. Volumetric Performance Fees

Pub. Util. Code Section 712.8(f)(5) established VPFs for recovery in rates for DCPP "in lieu of a rate-based return on investment and in acknowledgment of the greater risk of outages in an older plant that the operator could be held

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[98] Pub. Util. Code § 712.8(f)(6)(A).

[99] D.24-12-033 at 25.

liable for."[100] The statute authorizes PG&E "to recover in rates a volumetric payment equal to six dollars and fifty cents $6.50, in 2022 dollars, for each megawatt hour generated by DCPP during the period of extended operations beyond the current expiration dates, to be borne by customers of all load-serving entities, and an additional volumetric payment of $6.50, in 2022 dollars, to be borne by customers in the service territory of the operator."[101] Also similar to the Fixed Management Fee, the statute dictates that for VPFs, "the operating risk payment shall be adjusted annually by the commission using commission-approved escalation methodologies and adjustment factors."

PG&E requests the Commission's approval to recover a total combined VPF for DCPP Units 1 and 2 of $266.566 million for the Record Period.[102]

Several parties disputed PG&E's proposed use of the VPF revenues, as discussed in Section 10, but no party objected to PG&E's methodology for calculating the VPFs or the escalation factors applied to the total. PG&E's VPF request of $266.566 million for the 2026 record period is reasonable and approved.

6.2.3. Liquidated Damages Fund

PG&E's liquidated damages funding request of $75 million complies with the statute, is reasonable, and should be approved.

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[100] Pub. Util. Code § 712.8(f)(6).

[101] Pub. Util. Code § 712.8(f)(6).

[102] Ex. PG&E-04 Table 9-4.

Pub. Util. Code Section 712.8(g) establishes the liquidated damages fund:

> The commission shall authorize and fund as part of the charge under paragraph (1) of subdivision (l), the Diablo Canyon Extended Operations liquidated damages balancing account in the amount of twelve million five hundred thousand dollars ($12,500,000) each month for each unit until the liquidated damages balancing account has a balance of three hundred million dollars ($300,000,000).

Pub. Util. Code Section 712.8(i)(1) provides that the purpose of this liquidated damages funding is to offset potential replacement power costs resulting from an unplanned outage at DCPP when the Commission determines PG&E failed to meet the reasonable manager standard:

> During any unplanned outage periods, the commission shall authorize the operator to recover reasonable replacement power costs, if incurred associated with Diablo Canyon powerplant [sic] operations. If the commission finds that replacement power costs incurred when a unit is out of service due to an unplanned outage are the result of a failure of the operator to meet the reasonable manager standard, then the commission shall authorize payment of the replacement power costs from the Diablo Canyon Extended Operations liquidated damages balancing account described in subdivision (g).

In the event it is not necessary to use the liquidated damages funding to offset replacement power costs as provided in Pub. Util. Code Section 712.8(i)(1), the funds will be returned to customers in PG&E's service territory, as required by Pub. Util. Code Section 712.8(t). Rather than creating a new balancing account for the liquidated damages fund, the Commission approved in Resolution 5299-E PG&E's request to include a subaccount in the DCEOBA to record the liquidated damages amounts and recover them in customer rates.

In its Application, PG&E requests that the Commission approve its requested total combined liquidated damages funding forecast of $75 million for the Record Period.[103] This total request is the sum of: (1) the DCPP Unit 1 liquidated damages funding in the amount of $37.5 million for the DCPP Unit 1 extended operations period of January 1 through December 31, 2026, and (2) the DCPP Unit 2 liquidated damages funding in the amount of $37.5 million for the Unit 2 extended operations period of January 1 through December 31, 2026.[104]

No intervenor objected to PG&E's calculations. PG&E's liquidated damages funding request of $75 million complies with the statute, is reasonable and should be approved.

6.3. RA Substitution Capacity Costs

PG&E's RA substitution capacity cost forecast of $26.288 million for the extended operations period of January 1 through December 31, 2026 is approved.[105]

6.3.1. Background

In D.23-12-036, the Commission determined that PG&E would retain the responsibility, as the scheduling coordinator, to procure substitution RA capacity during periods when the DCPP units are on planned outages.[106] The Commission further specified that to ensure against potential cost shifts to PG&E's bundled service customers, PG&E would be authorized to recover from all LSEs the

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[103] Ex. PG&E-01 at 5-6.

[104] Ex. PG&E-01 at 5-6.

[105] Ex. PG&E-04 Table 9-4.

[106] D.23-12-036 at 86-87.

administrative and procurement costs associated with meeting DCPP's substitution RA capacity obligations, including associated penalties and costs borne by non-DCPP resources.[107]

D.24-12-033 determined that "the Commission has already determined that the use of the RA MPB is appropriate. The use of PCIA benchmarks is more transparent and aligns with the regulatory precedent, e.g., ERRA. Therefore, it is a reasonable and consistent choice to use in this proceeding."[108] Additionally, D.25-06-049 established a new methodology for calculating the RA MPB authorized in D.24-12-033 to calculate DCPP substitution capacity. The new methodology utilizes three years' transaction data when adopting the annual forecast RA MPB and four years' transaction data when adopting the annual final RA MPB.[109] The decision also ordered Energy Division to exclude from the MPB calculation affiliate and swap transaction data and to utilize a single transaction within a sleeve transaction in the RA MPB calculation.[110]

6.3.2. PG&E's Proposal

To develop its RA substitution capacity cost forecast, PG&E first determines the amount of RA substitution capacity needed during times when Diablo Canyon is expected to be offline or curtailed due to planned outages, tunnel cleaning, and/or other short-term curtailment events. This required

[107] D.23-12-036 at 87.

[108] D.24-12-033 at 32.

[109] D.25-06-049 OP 1.

[110] D.25-06-049 OP 1.

capacity is then multiplied by a market reference price to estimate the total procurement costs for meeting DCPP's RA substitution capacity obligations.[111]

PG&E uses the outage and curtailment schedules from the generation forecast and multiplies that amount with the 2025 Power Charge Indifference Adjustment (PCIA) system RA MPB, similar to the practice used in the ERRA Forecast proceeding.[112] Consistent with traditional ERRA Forecast modeling practices, PG&E will true-up the 2025 substitution capacity cost to reflect the final 2025 PCIA system RA MPB and update the DCPP RA substitution capacity cost forecast in the Fall using the forecast 2026 PCIA system RA MPB, unless otherwise directed by the Commission.[113] PG&E notes that its forecast does not include any additional administrative costs or potential compliance penalties costs and/or costs borne due to non-DCPP resources within PG&E's generation portfolio.[114]

As a result, PG&E seeks recovery from ratepayers of forecast RA Substitution Capacity Costs of $26.288 million for 2026 as shown in Table 2. Due to the decrease in the system RA MPB as well as the updated outage schedule, the forecasted RA substitution capacity costs decreased from $160.8 million to $26.288 million in the Fall Update.

[111] PG&E Opening Brief at 26.

[112] PG&E Opening Brief at 26.

[113] Ex. PG&E-01 at 3-4.

[114] Ex. PG&E-01 at 3-4 to 3-5.

Table 2: RA Substitution Capacity Cost Forecast

Year	Total
2024	$16,340,100
2025	$193,800,800
2026	$26,288,000
Total	**$236,428,900**

6.3.3. Party Comments

Several parties – TURN, SBUA, EPUC, and CalCCA – support using the RA MPB to calculate forecast RA substitution capacity although they recommend modifications to the MPB. TURN recommends using monthly RA MPB values that it estimates could save between $2.582 million and $6.686 million per year from 2026-2030, based on the 2025 forecast modifications modeled by Energy Division.[115] EPUC also recommends using monthly RA MPB values in place of the annual average price PG&E uses in its forecast and cites TURN's estimated savings calculations.[116] CalCCA argues that DCPP's 2026 substitution capacity forecast should be calculated using the methodology adopted prior to D.25-06-049 because "[t]hough the Commission is generally authorized to revise the RA MPB, it cannot do so with retroactive effect."[117] SCE states in its Reply Brief that CalCCA's proposal has already been litigated and rejected in R.25-02-005 and represents "an impermissible collateral attack on (D.25-06-049) and should

[115] Ex. TURN-01 at 29-32.

[116] EPUC Opening Brief at 22-23.

[117] CalCCA Opening Brief at 2.

also be rejected."[118] SBUA supports using the RA MPB methodology updated in D.25-06-049 but suggests additional changes to the methodology such as including data from longer term power purchase agreements, "arms-length" power purchase agreements, and pricing from the Western Electric Coordinating Council and other balancing authorities.[119]

A4NR offers its own 2026 DCPP RA substitution capacity forecast of $8,618,400 using PG&E's 2026 confidential forward price curve figures from system RA capacity contained in PG&E's response to Exhibit A4NR-01-Q001 and applying them to the 2026 scheduled outages identified in Exhibit PG&E-01-WP-C Resource Adequacy Substitution Capacity Cost Forecast supporting Chapter 3 of PG&E's prepared testimony.[120] A4NR states: "Based upon this hard evidence, PG&E's 'forecast' of RA substitution capacity costs is *per se* unreasonable."[121]

CARE states in its Opening Brief that "[t]he Market Price benchmark utilized by PG&E is not appropriate … because there exists a mismatch between the peak summer pricing and the timing of Diablo Canyon outages. The Commission should require PG&E to utilize their own internal monthly forward RA price curves in calculating RA substitution costs."[122]

PG&E argues in its Opening Brief that the RA MPB is "aligned with a series of Commission decisions related to other cost recovery treatment methods

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[118] SCE Reply Brief at 3-4.

[119] Ex. SBUA-01 at 7.

[120] Ex. A4NR-01 at 11-12 and Footnote 21.

[121] A4NR Opening Brief at 7.

[122] CARE Opening Brief at 17.

such as ERRA (i.e., bundled service generation rate), PCIA, and Cost Allocation Mechanism (CAM) ratemaking practices."[123] PG&E also cites D.23-12-036 that stated "the DCPP Extended Operations Cost Forecast proceeding should … utilize a process that mirrors the CAM process to determine the price of the volumetric NBC to be charged by each of the corporations."[124] Additionally, PG&E argues that its bundled service customers who receive both generation and transmission and distribution services are already required to pay the PCIA system RA MPB, for ratemaking purposes, when using RA capacity from PG&E's PCIA-eligible portfolio to meet their RA compliance obligations. PG&E argues: "Whether PG&E's bundled service customers use RA capacity from the PCIA-eligible portfolio to meet an RA substitution capacity obligation for DCPP or a non-DCPP resource, the same reference price must be used for ratemaking purposes to ensure a fair and equitable outcome. In other words, it would be discriminatory and arguably in violation of Pub. Util. Code Section 453(c) if the Commission requires PG&E's bundled service customers to pay one price to use PCIA-eligible resources for RA substitution capacity purposes while requiring DCPP customers to pay a different price for precisely the same product."[125]

Finally, PG&E argues that no party has presented a "comprehensive methodology that could serve as a viable alternative reference price to the

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[123] PG&E Opening Brief at 34.

[124] D.23-12-036 Conclusions of Law 55.

[125] PG&E Opening Brief at 35.

Commission's PCIA System RA MPB."[126] PG&E states that A4NR's proposal would effectively cap the RA substitution capacity forecast for DCPP at "levels available in the marketplace at the time the outages are forecast."[127] PG&E continues: "Requiring PG&E to effectively disregard capacity from its existing generation portfolio and solely rely on the RA market for DCPP's RA substitution capacity is nonsensical and would increase the total cost for customers."[128]

6.3.4. Discussion

As stated in D.24-12-033, the Commission "is cognizant of the pros and cons of the use of a PG&E estimated benchmark versus an administratively set price benchmark." Since that decision, however, D.25-06-049 has implemented substantial modifications to the RA MPB calculation methodology, which is reflected in the significantly lower 2026 Forecast MPB of $11.53 compared to the 2025 Forecast MPB of $42.54 calculated using the previous methodology. That decrease in the Forecast MPB has lowered the total requested revenue requirement amount for DCPP 2026 extended operations from $410 million to $382.233 million. PG&E also makes a persuasive argument that the same RA calculation methodology should be used across Commission proceedings incorporating RA values. TURN, EPUC, and SBUA agree in concept with using the updated RA MPB value to calculate RA substitution capacity costs for DCPP while offering ideas for further improving the RA MPB calculation.

[126] PG&E Opening Brief at 37.

[127] PG&E Opening Brief at 37.

[128] Ex. PG&E-03 at 3-6.

Finally, as stated in D.24-12-033, "the Commission has already determined that the use of RA MPB is appropriate."[129] In particular, D.24-06-004 states that "Energy Division will allocate the Resource Adequacy (RA) benefits of the Diablo Canyon Power Plant (DCPP) to all load-serving entities within each investor-owned utilities' service territory using the Cost Allocation Mechanism."[130] D.24-06-004 then states: "If an investor-owned utility (IOU) uses resources from an IOU's Power Charge Indifference Adjustment (PCIA)-eligible portfolio, the IOU may use the PCIA MPB to determine substitution capacity costs for Cost Allocation Mechanism resources."[131] In light of these two past Commission decisions, A4NR's proposed methodology for calculating DCPP RA substitution capacity costs is not an appropriate alternative. Finally, we find overly speculative the arguments made by TURN and EPUC to adopt the monthly RA MPB to calculate the DCPP RA substitution capacity cost, once the monthly RA MPB is available, as it is not evident now when such a Commission-produced monthly RA MPB will become publicly available or exactly how it will be calculated and used if it ever does become available.

Therefore, the RA MPB remains the reasonable and consistent choice to use in this proceeding.

6.4. Nuclear Fuel Costs

PG&E's nuclear fuel cost forecast and straightline amortization proposal are reasonable, comply with Pub. Util. Code Section 712.8(c)(1)(C), 712.8(h)(1),

[129] D.24-12-033 at 32.

[130] D.24-06-004 OP 14.

[131] D.24-06-004 OP 15.

and Commission decisions and resolutions interpreting those statutory sections, and are approved.

PG&E requests that the Commission adopt its nuclear fuel expense forecast of $135.734 million for 2026[132]. PG&E explains that these expenses stem from the contracted purchases of nuclear materials to support the nuclear fuel reload needs for each unit and cover the costs of uranium, conversion services, enrichment services, fabrication, and sales and use taxes, for the specific core design. Additionally, there are miscellaneous engineering expenses associated with the core nuclear fuel analysis.[133]

In addition to its forecast, PG&E requests that the Commission approve a straightline amortization method for recovering nuclear fuel expenses over the 2025-2030 period. PG&E presents both the 2024 through 2030 as-spent nuclear fuel expenditures as well as PG&E's 2025 through 2030 straightline amortization cost recovery proposal. According to PG&E, straight-line amortization offers the lowest financing cost compared to as-spent recovery and smooths rates for all California electric customers during the extended operations period.

A4NR states in its Opening Brief that it will not relitigate in this proceeding the compatibility of PG&E's treatment of the amortized fuel procurement obligations with Pub. Util. Code Section 712.8(c)(1)(C) as the issue is the subject of a pending Petition A4NR Seeking Writ of Review of D.24-12-033 and D.25-07-041.[134]

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[132] PG&E Opening Brief at 18.

[133] PG&E Opening Brief at 19.

[134] A4NR Opening Brief at 8.

6.5. PG&E's Generation and Generation Revenue Forecasts

The Commission finds PG&E's methodology to calculate forecast CAISO energy market revenues reasonable and approves the forecast of $842.676 million in 2026 revenues.[135] This figure incorporates the $728,958 undercounting of CAISO revenues in PG&E's original forecast revealed by CalCCA and accepted by PG&E.[136] [137] The revised Energy Index MPB calculated by Energy Division decreased DCPP energy market revenue forecast from $934.925 million originally forecast.

6.5.1. PG&E's Methodology

In its Application, PG&E describes the methodology used to forecast CAISO energy market revenues as follows: The forecast for generation volumes is multiplied by a market reference price to produce the energy market revenue forecast. PG&E uses a market reference price that is analogous to the PCIA energy index benchmark used in the ERRA forecast proceeding, using a portfolio weighting factor calculation based on actual DCPP CAISO generation and revenue data as opposed to the entire PCIA-eligible portfolio.[138]

PG&E updated the market reference price calculation in the Fall Update using the latest NP15 Platts price curves provided by the Commission as part of its standard PCIA energy index benchmark updating process. PG&E's forecast of CAISO energy market revenues is as follows:

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[135] Ex. PG&E-04 at 8-9.

[136] CalCCA October 20, 2025 Comments at 2-3.

[137] PG&E Reply Comments on the Fall Update at 9.

[138] Ex. PG&E-01 at 6-2.

Table 3: DCPP CAISO Energy Market Revenues

Year	Total generation (GWh)	CAISO Market Reference Price ($/Megawatt-Hour)	Generation Revenues $000
2024	1,442	55.52	80,044
2025	10,753	50.61	544,205
2026	18,203	51.36	842,676

The generation energy market revenue forecast serves to offset the costs of DCPP's extended operations.

6.5.2. Party Comments and Discussion

EPUC states in its Opening Brief that "[t]he record in this proceeding demonstrates that PG&E's forecast cost of operations and requested revenue requirement of $410 million for 2026 are not just and reasonable."[139] EPUC witness James Leyko testifies that PG&E is forecasting 18,203 GWh of extended operations generation in 2026 compared to 10,753 GWh of generation in 2025 and 1,442 GWh of generation in 2024.[140] Mr. Leyko also notes that the net operational revenue requirement increased by 4 percent from $851,334 in the September 1, 2023 through December 31, 2025 record period to $887,082 in the 2026 record period driven by an increase in O&M costs. Other than stating trends in such operational costs, EPUC does not otherwise explain how the market revenue forecast is inaccurate.[141]

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[139] EPUC Opening Brief at 7.

[140] Ex. EPUC-01 at 2.

[141] Ex. EPUC-01 at 4-11.

CalCCA states in its October 20, 2025 on the Fall Update that PG&E had undercounted 2026 CAISO revenue by $728,958 by entering the incorrect off-peak energy MPB into its calculation.[142] PG&E accepted that correction in its Reply Comments on the Fall Update.[143]

Upon review of PG&E's request and party comments, the Commission finds PG&E's forecasted CAISO energy market revenues reasonable and approves them adjusted for the corrected 2026 CAISO revenue amount.

6.6. Netting of CAISO Revenues

PG&E requests that the Commission approve the consolidated net revenue requirement of $382.233 million that will be used to allocate costs to the three large IOUs and will be the basis for setting rates.[144] The Commission approves a consolidated net revenue requirement of $382.233 million.

In its Fall Update, PG&E consolidates PG&E's Diablo Canyon Extended Operations cost updates, DCPP Electric Generation Revenue Forecast Update, VPF Update, RA Substitution Cost Forecast with the cost forecasts presented in PG&E's July 8, 2025 errata testimony. Then, the DCEOBA balance from the end of year 2025 and Revenue Fees and Uncollectibles (RF&U) and the Franchise Fee and Uncollectibles (FF&U) amounts are included for developing the Diablo Canyon extended operations revenue requirement for ratesetting.

No party disputed the computation of netting the CAISO revenues.

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[142] CalCCA October 20, 2025 Comments at 2-3.

[143] PG&E Reply Comments on the Fall Update at 9.

[144] Ex. PG&E-04 Table 9-4.

Upon review, a consolidated net revenue requirement of $382.233 million is approved. The reduction from the requested amount reflects the changes made by this decision.

7. Non-Bypassable Charge

The Commission finds that the IOUs' proposal for allocation of the DCPP extended operations cost is consistent with the direction provided in D.23-12-036 and approves it.

7.1. Background and the IOUs' Joint Proposal

Pursuant to SB 846, in D.23-12-036, the Commission authorized PG&E, SCE, SDG&E; Liberty Utilities/CalPeco Electric (Liberty); Bear Valley Electric Service, a division of Golden State Water Company (Bear Valley); and Pacific Power, a division of PacifiCorp to establish a new NBC to collect DCPP extended operations costs.[145] The Commission required PG&E, SCE, and SDG&E "to provide joint testimony proposing an allocation among themselves of the statutorily defined [DCPP] extended operations costs applicable to all load serving entities, and the revenue associated with the $6.50 per megawatt-hour volumetric fee under Pub. Util. Code Section 712.8(f)(5), in each of PG&E's DCPP Extended Operations Cost Forecast application proceedings[.]"[146] In compliance with the requirements, the IOUs, jointly, presented their proposed allocation of the DCPP extended operations costs and the DCPP NBC rates applicable to each utility's customers.

[145] D.23-12-036 at 138-139, OP 14.

[146] D.23-12-036 at OP 7.

The IOUs propose allocating the DCPP extended operations costs using a 12-month Coincident Peak (12-CP) load forecast, as required by D.23-12-036.[147] They utilize the California Energy Commission's (CEC) peak load forecast developed for use in the Commission's RA program.[148] Then, the utilities develop allocation factors by developing a percentage that each utility contributes to the total calculated forecast peak load.[149] The IOUs updated the allocation of DCPP extended operations costs based on the more recent 2025 CEC 12-CP load forecast in the Fall Update, as shown below.[150]

Table 4: 12-CP Load Allocation Factors

IOU	MW	Percent
PG&E	170,248	44.19
SCE	176,681	45.86
SDG&E	38,342	9.95
Total	385,270	100.00

7.2. Party Positions

A4NR argues in its Opening Brief that $55,461,049 of "unreasonable project costs" associated with projects identified by PG&E's PMO++ review and $12,673,805 in dry cask storage, as well as $152,218,500 in "unreasonable RA substitution capacity costs" should be removed from the NBC.[151]

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[147] D.23-12-036 at COL 30, OP 14.

[148] Ex. PG&E-01 at 10-3.

[149] Ex. PG&E-01 at 10-4.

[150] Ex. PG&E-04 Table 10-2.

[151] A4NR Opening Brief at 2 and 9.

7.3. Discussion

In D.23-12-036, the Commission established a two-step process for allocating net statewide DCPP extended operations costs to the LSEs in each IOU service area. The first step involves allocation of DCPP costs between the three large IOUs based on each IOU's share of 12-CP load. The Commission explained, "[g]iven that ensuring system reliability is a key legislative rationale for the billions of ratepayer dollars that may be spent to keep DCPP operating, it follows that allocating the costs of those extended operations based on an IOU's share of a [12-CP] is fair and equitable."[152]

The second step in the process established in D.23-12-036 allocates each IOU's DCPP Cost revenue requirement among the customers within its distribution service territory based on 12-CP demand. The Commission directed that "[t]he process for allocating these eligible costs to the LSEs *within* each IOU's territory should mirror the Cost Allocation Mechanism (CAM)," which, as the decision points out, utilizes the 12-CP demand allocation approach. The Commission reasoned that "[b]ecause LSEs are familiar with the CAM and it is a proven mechanism for allocating costs among the LSEs in a large electrical corporation's territory, it is reasonable to use a process that mirrors the CAM process to allocate DCPP extended operations costs within each IOU's territory."[153]

After reviewing the IOUs' proposed methodology, the Commission concludes that the IOUs' proposed methodology and rate design for allocating

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[152] D.23-12-036 at 73-74.

[153] D.23-12-036 at 75.

the DCPP costs, complies with the Commission's directives in D.23-12-036, and therefore, is approved. PG&E must provide SCE and SDG&E with the final revenue requirement for each of the respective utilities as of the effective date of this decision. PG&E, SCE, and SDG&E must file a Tier 1 Advice Letter and revised tariff sheets within 60 days of the issuance of this decision to implement this Decision.

8. Modification to DOELBA Preliminary Statement

PG&E's request to update its allocation of DOE settlement proceeds based on cost causation principles and to establish a new subaccount for U.S. DOE reimbursement attributable to DCEOBA-funded activities is approved.

8.1. Background

PG&E entered into a settlement agreement with the DOE in September 2012 to resolve litigation surrounding DOE's failure to perform under spent nuclear fuel disposal agreements for DCPP and Humboldt Bay Power Plant (HBPP). Under the terms of the agreement, PG&E recovered a lump sum amount reimbursing PG&E for the costs of spent nuclear fuel storage at DCPP and HBPP through 2010. In addition, the settlement approved an annual administrative claims process that requires PG&E to document its costs of spent nuclear fuel storage in defined recoverable categories and submit an annual claim to be reviewed by DOE staff and approved by the U.S. Department of Justice.[154] DOE proceeds are then credited to the DOE Litigation Balancing Account (DOELBA) in the year received. Those funds are then transferred annually, net of outside litigation costs, to the Portfolio Allocation Balancing Account (PABA) and the

[154] Ex. PG&E-01 at 2-32.

Nuclear Decommissioning Adjustment Mechanism (NDAM) as part of the annual electric true-up advice letter filing.[155]

The current settlement agreement with the DOE expires in 2025, which creates uncertainty for future recovery of the costs of storing spent nuclear fuel in dry casks at DCPP. Nonetheless, PG&E has included a forecast of continued revenues from DOE and proposes to continue the crediting process for DCPP, subject to true-up when the actual proceeds are received.[156] In the event the DOE settlement is not extended beyond 2025, PG&E intends to file new lawsuits against the DOE to recover the costs of the spent nuclear fuel storage starting in 2026.[157]

The Commission approved in its 2014 GRC a settlement crediting the proceeds of the DOE litigation settlement to generation and nuclear decommissioning rates. Currently, 76.21 percent of the DOE litigation settlements are allocated to PABA while 23.79 percent of the funds are allocated to the HBPP Decommissioning based on the credit amount agreed to in that settlement.[158] Allocation amounts for 2024 and 2025, approved in D.24-12-033, are as follows:

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[155] Ex. PG&E-01 at 2-33.

[156] Ex. PG&E-01 at 2-33.

[157] Ex. PG&E-01 at 2-33.

[158] Ex. PG&E-01 at 2-34.

Table 5: DCPP Allocation Percentage for DOE Credits[159]

Year	DCPP Allocation to PABA	DCPP Allocation to DCEOBA	HB ISFSI Allocation to NDAM	Total DOE Settlement
2024	19.0%	0%	81.0%	100%
2025	15.0%	0%	85.0%	100%

For forecast year 2026, PG&E proposes to update its allocation of the DOE settlement proceeds to refund the settlement proceeds according to cost causation principles with small and declining refund percentages to PABA as those funds are for costs already funded through the 2023 GRC generation revenue requirements for 2024 and 2025. PG&E also proposes to revise the DOELBA to add a subaccount for DOE settlement proceeds attributable to DCEOBA funded activities.[160]

Table 6: Proposed DCPP Allocation Percentage for DOE Credits[161]

Year	DCPP Allocation to PABA	DCPP Allocation to DCEOBA	HB ISFSI Allocation to NDAM	Total DOE Settlement
2026	5.3%	52.2%	42.5%	100%
2027	1.7%	45.9%	52.4%	100%
2028	0%	62.2%	37.8%	100%
2029	0%	68.2%	31.8%	100%
2030	0%	15.2%	84.8%	100%

[159] Ex. PG&E-01 at 2-34.

[160] Ex. PG&E-01 at 2-34 to 2-35.

[161] Ex. PG&E-01 at 2-35.

PG&E forecasts $12.587 million in DOE settlement proceeds directly attributable to spent fuel management costs funded through the DCEOBA for the 2024-2025 claim period. PG&E added these estimated proceeds as a credit to the 2026 DCEOBA revenue requirement in the Fall Update, with the credit subject to true up through the DOELBA for the final recorded payment from the DOE for the 2024-2025 claim.[162]

8.2. Discussion

No parties opposed PG&E's proposal to update its allocation of DOE settlement proceeds based on cost causation principles and to establish a new subaccount for DOE reimbursement attributable to DCEOBA-funded activities.

After reviewing PG&E's proposed changes, the Commission finds that updating the allocation of DOE settlement proceeds and creating a new sub-account for DOE reimbursement attributable to DCEOBA-funded activities is reasonable and should be approved.

9. Volumetric Performance Fees Spending Plan

The Commission determines that PG&E's VPF spending plan application is consistent with Pub. Util. Code Section 712.8(s)(1) requirements.

9.1. Background

Pub. Util. Code Section 712.8(s) provides the following guidance regarding the spending of DCPP VPFs:

1. The operator shall submit to the commission for its review, on an annual basis the amount of compensation earned under paragraph (5) of subdivision (f), how it was spent,

[162] Ex. PG&E-01 at 2-35.

and a plan for prioritizing the uses of such compensation the next year. Such compensation shall not be paid out to shareholders. Such compensation, to the extent it is not needed for Diablo Canyon, shall be spent to accelerate, or increase spending on, the following critical public purpose priorities:

a. Accelerating customer and generator interconnections.

b. Accelerating actions needed to bring renewable and zero carbon energy online and modernize the electrical grid.

c. Accelerating building decarbonization.

d. Workforce and customer safety.

e. Communications and education.

f. Increasing resiliency and reducing operational and system risk.

2. The operator shall not earn a rate of return for any of the expenditures described in paragraph (1) so that no profit shall be realized by the operator's shareholders. Neither the operator nor any of its affiliates or holding company may increase existing public earning per share guidance as a result of compensation provided under this section. The commission shall ensure no double recovery in rates.

In D.23-12-036, the Commission directed PG&E to file an annual application for review of its planned use of Pub. Util. Code Section 712.8(f)(5) revenues to confirm its proposed plan is consistent with Pub. Util. Code Section 712.8(s), as well as to review PG&E's past use of funds.[163] The Commission stated that "while we interpret [Pub. Util. Code Section 712.8(s)] as providing PG&E some amount of discretion on the use of surplus performance

[163] D.23-12-036 at OP 15.

based fees, subject to the statutory conditions and review discussed below, in the event actual recorded costs are more than 15 percent above PG&E's approved forecast then PG&E must first use the volumetric performance based fees to offset any costs above that amount before they be used for another purpose."[164] D.23-12-036 then orders: "The compensation earned under [Pub. Util. Code Section 712.8(f)(5)] should be used to offset any costs in excess of 15 percent above PG&E's approved annual DCPP Extended Operations Cost Forecast application, as considered in the annual true-up process adopted in this decision, before these funds can be used for the public purpose priorities in [Pub. Util. Code Section 712.8(s)(1)]."[165]

In compliance with D.23-12-036, PG&E seeks the Commission's approval of its plan for 2026 VPF expenditures covering the Record Period pursuant to the public purpose priorities identified in Pub. Util. Code Section 712.8(s)(1). In its application, PG&E proposes a "waterfall" of priority uses, starting with defined customer-benefitting public purpose programs, followed by an allocation of contingency funds for key risk and safety programs, and then contribution of any remaining funds to offset Diablo Canyon operating costs.[166] In this way, according to the proposal, all of the VPFs will be first spent on critical public purpose priorities. However, in the event PG&E earns less than the forecasted

[164] D.23-12-036 at 110-111.

[165] D.23-12-036 at OP 60.

[166] Ex. PG&E-01 at 7-1 to 7-2.

amount of volumetric fees in 2026, PG&E will not allocate 100 percent of the funds for defined uses, so less would be available for use.[167]

The total forecast for the VPFs collected in 2026 is $266.566 million. The higher electricity generation forecast included in PG&E's Fall Update and a higher expense escalation increased the VPF amount from $263.4 million originally forecast in the Application.[168] The proposal includes the following programs, which continue and incorporates seven programs approved in the 2025 VPF Spending Plan.

1. Power Generation (PG) Accelerated/Enhanced Asset Management, Communications, Workforce Safety, and Renewable/Zero Carbon Energy Activities: Asset Management, Inspection, and Maintenance Activities of PG System Infrastructure ($22 – 40 million) aims to address gaps identified during PG&E's ISO 55001 certification process, incorporate corrective actions stemming from asset failures sooner, and implement new, industry-leading practices for proactively managing asset lifecycle and reducing risk.
2. PG Accelerated/Enhanced Asset Management, Communications, Workforce Safety, and Renewable/Zero Carbon Energy Activities: PG Communications ($0.2 – 0.3 million) aims to enhance public safety communications.
3. PG Accelerated/Enhanced Asset Management, Communications, Workforce Safety, and Renewable/Zero Carbon Energy Activities: PG Workforce Safety Initiatives ($0.5 – 1.0 million) enables new workforce safety initiatives.

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[167] Ex. PG&E-01 at 7-1.

[168] Ex. PG&E-04 at 7.

4. PG Accelerated/Enhanced Asset Management, Communications, Workforce Safety, and Renewable/Zero Carbon Energy Activities: Zero Carbon Energy Activities ($0.5 – 1.2 million) aims to advance work on carbon capture technology at PG&E natural gas generation.
5. PG Accelerated/ Enhanced Asset Management, Communications, Workforce Safety, and Renewable/Zero Carbon Energy Activities: Renewable Energy Activities ($0.8 to 2.5 million) aims to advance work on potential Battery Energy Storage Systems sites for renewable energy integration.
6. Accelerating Interconnections and Actions to Reduce Operational Risk and Modernize the Grid More Efficiently Through Operating System Enhancements: Electric Generation Interconnection ($5-15 million) aims to enable more efficient application processing to support expedited timelines for customer interconnections, as well as work through a backlog of customer interconnection work created by the NEM 2.0 sunset in 2023.
7. Accelerating Interconnections and Actions to Reduce Operational Risk and Modernize the Grid More Efficiently Through Operating System Enhancements: Propel ($35-55 million) is a system upgrade produced by the company SAP that aims to simplify processes, resulting in improved customer interconnection timelines, enhanced grid modernization and resiliency, and reduced operational risk.
8. Reliability Battery Program (previously Batteries for Resiliency) ($4.6-21.4 million) aims to expand existing wildfire related battery programs supporting Behind the Meter Batteries for Resiliency and target outages beyond wildfire and customers outside of high fire risk areas.

9. Electric Vehicle Detection for Forecasting and Vehicle Grid Integration ($0.5-1.0 million) aims to enable EV detection and data gathering.
10. Customer Electrification Experience: Materials and Training for Comprehensive Electrification Support ($400,000-550,000) aims to accelerate development of training and materials for PG&E Customer Service Representatives and outreach to third-parties involved in customer electrification experience (e.g., automotive dealerships).
11. Customer Electrification Experience: Online Resources for Comprehensive Electrification Support ($1.7-3.1 million) aims to support development of online resources for comprehensive electrification support.
12. Customer Electrification Experience: Residential Building Electrification Support ($1.2-2.5 million) aims to expand and/or supplement existing program offerings to fill gaps in customers served or Building Electrification measures offered and thus provide a more holistic solution to customers who are interested in Building Electrification.
13. Programs to support building decarbonization for small businesses ($1.5-2.5 million) aims to support expanded programs to support small business in building decarbonization objectives.
14. One VM ($10-15 million) aims to enable map-based work execution, monitoring, and validation application that supports wildfire mitigation.
15. Pre-staging of Temporary Generation in Support of Winter Storms ($4-8 million) aims to deploy strategy to pre stage temporary generation in support of winter storms to promote workforce safety, reduce costs of mobilization efforts, and other benefits.

16. PG&E Contingency Uses: (1) for Safety and Risk, and (2): DCPP Operational Costs ($40-92 million) aims to support Safety and Risk programs: MWCs: BH (Electric Distribution Routine Emergency), BF (Electric Transmission & Distribution Patrol/Inspection), GC (Electric Distribution Substation O&M), GA (Electrification Transmission & Distribution Maintenance Overhead Poles), BA (Electrical Distribution Operate System).[169]

Finally, PG&E states that "VPF revenues will only be spent on new programs, work that was not forecast in any other rate case, or work that exceeds authorized amounts from the 2023 GRC or any rate case. Incrementality will be presented in the post-spend report and verified annually by an independent third-party auditor."[170]

9.2. Party Positions

Cal Advocates argues that four VPF projects "could result in customers paying for projects that may provide future shareholder benefits, and which PG&E may abandon after DCPP extended operations end to avoid violation of statute."[171] Cal Advocates further states that "PG&E noted these four projects have the potential to result in on-going expenses for PG&E beyond the conditionally approved extension of DCPP operations, citing PG&E's response to Cal Advocates data request 002_Q002 asking about the mobile app in Project 1.b – Power Generation Communication. When asked "Does PG&E plan to continue the operations of this 'mobile app' beyond the retirement date of the

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[169] Ex. PG&E-01 at 7-6 to 7-9, Table 7-11.

[170] Ex. PG&E-03 at 6-20.

[171] Cal Advocates Opening Brief at 10.

DCPP, and the end of the collection of VPFs?", PG&E responds "Yes" and "At this time, PG&E has not determined how this program will be funded past the retirement date of DCPP. If PG&E were to fund the continued operation of the program with funding from a source other than VPF revenues, PG&E would comply with the associated requirements of that funding source, which may or may not include restrictions around earnings per share impacts."[172] Cal Advocates notes that PG&E also indicated in data request responses that it plans to continue the operation of three additional programs requesting VPF funding after the end of collection of VPF funds.[173] That identified spending belongs to the Electric Vehicle Detection for Forecasting and Vehicle-Grid Integration program, the EV savings calculator included in the Online Resources for Comprehensive Electrification Support program, and the One VM application.[174]

Cal Advocates notes that Public Utilities Code Section 712.8(s)(2) authorizing the VPF program states that "[n]either the operator nor any of its affiliates or holding company may increase existing public earning per share guidance as a result of compensation provided under this section." Cal Advocates concludes: "As these four projects may become a part of future revenue requirements, and could potentially violate Pub. Util. Code Section 712.8(s)(2), they should be removed from the VPF Spending Plan."[175]

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[172] Ex. PAO-1 Attachment 2. CalAdvocates_002-Q002 and Answer 002.

[173] Ex. PAO-01 Attachment 2. PG&E responses to DR 02 Answers 004c., 005d. and 006a.

[174] Ex. PAO-01 at 6.

[175] Ex. PAO-01 at 6.

PG&E responds to Cal Advocates' argument by charactering it as "speculative" and stating "whether a program continues beyond 2030 has no bearing on compliance with shareholder prohibitions in [Pub. Util. Code Section 712.8(s)(2)]."[176] PG&E continues: "No requirement exists from [Pub. Util. Code Section 712.8(s)(2)]—or any other part of the statute—that VPF-funded programs must conclude by 2030 to qualify for the 2026 VPF spend plan. Whether or not projects seek funding beyond the end of extended operations bears no relation to [Pub. Util. Code Section 712.8(s)(2)], which prohibits PG&E from earning a rate of return or increasing earnings per share, along with a requirement of no double recovery in rates, as a result of the VPFs."[177]

TURN argues that PG&E's proposal will allow leftover funds from underspent MWC to pay for other costs and thus benefit shareholders rather than pay for overspend in other MWCs in the same Safety and Risk Maintenance Program.[178] TURN argues that VPF funds should only go to the Safety and Risk Maintenance Program only if PG&E "can demonstrate that all identified MWCs are collectively overspent. Allowing selective application of VPFs to individual overspent MWCs, while ignoring underspending in other MWCs, would result in an impermissible transfer of VPFs to shareholders."[179] Similarly, TURN cites similar past overspending issues in the hydroelectric generation MWCs in the Power Supply program and argues that "PG&E should only be permitted to

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[176] Ex. PG&E-03 at 6-7.

[177] Ex. PG&E-03 at 6-7.

[178] Ex. TURN-01 at 39.

[179] Ex. TURN-01 at 40.

apply VPFs to hydro generation to the extent that total spending within the Power Supply category exceeds total authorized revenues in that year."[180]

PG&E responds to TURN's argument in its Opening Brief by stating: "While PG&E does not agree with TURN's position, PG&E affirms that it will only apply VPF revenues to the Safety & Risk programs where both the 2026 MWC category and MAT code level of the proposed program are above authorized imputed amounts, with the exclusion of balancing accounts involving the return of unused funds to customers."[181]

Finally, TURN argues that PG&E's Supplemental Testimony responding to D.25-06-002 is inadequate.[182] D.25-06-002 stated:

> [I]n addition to the requirements set out in statute and prior Commission decisions, where PG&E takes advantage of opportunities to align with the guiding principle of reducing upward pressure on rates, it must explain this alignment in its spending plan submittals, starting with the 2026 VPF spending plan. Additionally, to the extent there are aspects of the plan that do not prioritize alignment with the guiding principle of reducing upward pressure on rates, PG&E must provide an explanation.[183]

TURN argues that "[w]hile PG&E does provide some text asserting that its VPF programs are aligned with the guiding principle of affordability, there is no factual support for these assertions" and notes that "PG&E failed to provide any sort of cost/benefit analysis of the VPF programs to demonstrate that proposed

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[180] Ex. TURN-01 at 49.

[181] PG&E Opening Brief at 50.

[182] Ex. TURN-01 at 50.

[183] D.25-06-002 at 17.

spending would benefit ratepayers."[184] TURN argues that "[b]ecause of PG&E's failure to meet its burden of proof required in D.25-06-002, the Commission should reject PG&E's VPF plan."[185]

PG&E responds that "[n]either the statute nor D.25-06-002 mandates a specific quantitative methodology for demonstrating affordability. PG&E provided factual support that each program in the 2026 VPF spend plan promotes affordability. Again, the 2026 VPF spend plan already aligns with the principle of affordability because affordability is a core priority at PG&E."[186]

Finally, TURN highlights in its Reply Brief that D.23-12-036 found regarding VPF spending that "the Commission may render a decision that replaces or modifies the PG&E proposal utilizing proposals made by other parties to the proceeding."[187] In its Opening Brief, CUE highlights that the Scoping Memo for A.25-03-015 excludes from the proceeding scope "[w]hether the Commission should review VPF spending plans beyond evaluating whether they comply with § 712.8(s) requirements and procedural requirements from D.23-12-036."[188] CUE concludes: "Thus, the Commission cannot direct PG&E to adopt any VPF spending proposals offered by intervenors."[189]

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[184] Ex. TURN-01 at 50.

[185] Ex. TURN-01 at 52.

[186] Ex. PG&E-03 at 6-18.

[187] TURN Reply Brief at 9.

[188] CUE Opening Brief at 5.

[189] CUE Opening Brief at 5.

A4NR argues that the VPF plan should not be approved because Pub. Util. Code Section 712.8(s)(1) states that "[s]uch compensation, to the extent it is not needed for Diablo Canyon, shall be spent to accelerate, or increase spending on, the following critical public purpose priorities."[190] A4NR argues that "[i]f the VPF revenues are considered 'not needed for Diablo Canyon' despite the massive operating deficit PG&E forecasts for 2026, could there ever be circumstances when the funds are considered needed? Ignoring this crucible, PG&E's Application assembles an evolving mix of nascent spending ideas too recently conceived to receive General Rate Case scrutiny."[191]

Similarly, EPUC argues that PG&E should not be allowed to seek $263.4 million in VPF funds in light of the then-projected $410 million shortfall of CAISO market revenue.[192] EPUC also argues that the 115 percent guideline for allowing VPF spending on public purpose programs set in D.23-12-036 should not apply to this Application "where the Commission is to determine the reasonableness of forecasted costs, and no DCPP Extended Operations Cost Forecast application has yet been approved for 2026. PG&E cannot use this barrier to defend its forecast proposal."[193]

PG&E responds to this category of criticism by stating the issue has already been resolved by D.23-12-036's requirement that VPF funds support

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[190] Ex. A4NR-01 at 19.

[191] Ex. A4NR-01 at 21.

[192] EPUC Opening Brief at 26.

[193] EPUC Opening Brief at 24-25.

operating expenses only when such expenses exceed the 115 percent overspending threshold.[194]

A4NR argues for allocating the VPF benefits to SCE and SDG&E service customers in addition to PG&E customers by directing $72.6 million in VPFs collected from SCE and SDG&E service territories to defray DCPP's 2026 operating deficit.[195] CARE cites Public Utilities Code Section 453(a) and 453(c) "prohibit[ing] a public utility from charging rates that subject any corporation or person to any prejudice or disadvantage."[196] CARE makes a similar argument stating: "As a matter of equity PG&E's proposed spending plan provides no benefit to SDG&E and SCE customers unless the funds are used to support DCPP which was the intention of SB 846. Utilizing the VPF funds to lower the revenue requirement is equitable to all the utilities and the ratepayers."[197]

PG&E responds by once again stating the issue has already been resolved by D.23-12-036's guideline that only requires VPF funds to go to operating expenses that exceed the 115 percent overspending threshold.[198]

With respect to specific VPF spending programs, CARE argues that:

- PG&E has not provided enough detail about the PG Asset Management, Inspection, and Maintenance Activities program to evaluate the dollar amounts for each related

[194] Ex. PG&E-03 at 6-5.

[195] CARE Opening Brief at 11-12.

[196] CARE Opening Brief at 11.

[197] CARE Opening Brief at 17.

[198] Ex. PG&E-03 at 6-5.

activity and how PG&E's ISO 5501 certification benefits customers or helps extend DCPP operations.

- Spending on Zero Carbon Energy Activities such as carbon capture does not actually produce zero carbon emissions and will enrich shareholders since they are being spent on utility-owned generation.
- Renewable Energy Activities spending will add to PG&E's rate base and may already be covered by a recent $15 billion loan guarantee from the DOE.
- Propel Program upgrades spending needs further definition on how much PG&E will be spending on individual programs and may already be covered by the DOE's $15 billion loan guarantee.
- PG&E should not be allowed discretion on how to spend its contingency VPF funds since the funds should lower DCPP's revenue requirement.[199]

PG&E responds that "[n]one of the activities in PG&E's 2026 VPF spend plan are being subsidized by the referenced DOE loan." PG&E adds that the DOE loan "is a low-interest rate replacement source of long-term capital that PG&E would otherwise seek from debt markets" and "does not expand PG&E's rate base and will not fund any work that is not otherwise approved by the appropriate regulator (this Commission, the Federal Energy Regulatory Commission, etc.)."[200]

PG&E also states that it already "provides dollar ranges for all programs consistent with testimony for the approved 2025 VPF spend plan."[201] PG&E

[199] Ex. CARE-01 at 17-20.

[200] Ex. PG&E-03 at 6-9 to 6-10.

[201] Ex. PG&E-03 at 6-10.

states that funding the ISO 55001 certification process "will allow Power Gen to accelerate maturity and build out of the (Asset Management System) to improve its capability to manage its business and asset risks."[202] PG&E states about its carbon capture program that "[w]hile zero emissions are unlikely any time soon, PG&E is committed to fully exploring options to operate these facilities as emission free as possible throughout their useful life."[203] PG&E also responds to CARE's argument regarding VPF spending on utility-owned generation that "[w]ork proposed to be performed under this program does not include the installation of infrastructure that would be additive to PG&E's rate base."[204] Finally, PG&E responds to CARE's argument on contingency spending that the proposed uses of contingency VPF funds are the same MWCs approved in the 2025 VPF spending plan."[205]

CUE supports PG&E's VPF spending plan, writing in its Opening Brief that "[t]he record evidence demonstrates that PG&E's 2026 VPF spending plan is consistent with [Pub. Util. Code Section 712.8(s)] and all Commission requirements and should be approved."[206] Similarly, SBUA supports PG&E's 2026 VPF Spending Plan while encouraging additional support of energy efficiency and small business decarbonization spending.[207]

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[202] Ex. PG&E-03 at 6-11.

[203] Ex. PG&E-03 at 6-12.

[204] Ex. PG&E-03 at 6-12.

[205] Ex. PG&E-03 at 6-13.

[206] CUE Opening Brief at 6.

[207] SBUA Opening Brief at 4-5.

9.3. Conclusion

In D.23-12-036, the Commission directed PG&E to file an annual application for review of its planned use of Pub. Util. Section 712.8(f)(5) revenues to confirm its proposed plan is consistent with Pub. Util. Code Section 712.8(s). In D.23-12-036, the Commission noted that SB 846 "[d]oes not rank or prioritize the critical public policy priorities." The Commission directed: "Accordingly, while the Surplus Performance-Based Fees Application shall detail PG&E's spending proposals, PG&E is not required to justify how it intends to allocate surplus funds among the listed categories. The Commission's review of PG&E's Application will be focused on determining whether the proposed spending properly falls within one or more of the categories identified in Pub. Util. Code Section 712.8(s)(1), and that the spending would not result in double recovery in rates, cause compensation to be paid out to PG&E shareholders, or cause PG&E to earn a rate of return on any of the expenditures."[208] The Commission also stated that "[t]here would be no purpose in having the Commission review PG&E's proposed usage of funds if the Commission did not also have the ability to modify or reject PG&E's proposed spending, as needed."[209]

D.25-06-002 provided additional guidance as to how PG&E should prioritize spending of VPF funds, stating: "[W]e encourage PG&E to look for opportunities to structure and plan expenditures in ways that provide additional benefits to ratepayers. VPF spending on capital projects, particularly distribution and transmission projects, and the acceleration of existing projects, are options

[208] D.23-12-036 at 114.

[209] D.23-12-036 at 111.

PG&E could consider in its VPF plans in order [sic] reduce upward rate pressure."[210]

Upon review of the proposed plan and testimony, the Commission determines that the proposed 2026 VPF spending plan is consistent with Pub. Util. Code Section 712.8(s)(1) requirements.

We find that PG&E has provided sufficient detail about each of the 16 VPF program areas in Chapter 7 of its Prepared Testimony for the Commission to determine that the proposed spending complies with the criteria set forth in D.23-12-036. First, each of the proposed VPF programs falls within at least one of the spending categories identified in Pub. Util. Code Section 712.8(s)(1), which no party has disputed. The Commission also finds that the programs will not increase shareholder profits, consistent with Pub. Util. Code Section 712.8 (s)(2).

Responding to Cal Advocates' concern that four of the proposed VPF programs may continue past 2030, we agree with PG&E that a VPF-funded program's duration past 2030 has no bearing on its compliance with shareholder prohibitions in Pub. Util. Code Section 712.8(s)(2) and that there is no requirement that a VPF-funded program conclude by 2030. Similarly, we find TURN's concerns regarding underspending in individual MWCs compared to the total Safety & Risk program to be well-intentioned but overly speculative in concluding that such underspent funds will necessarily benefit shareholders in violation of Pub. Util. Code Section 712.8(s). Additionally, PG&E has affirmed in its Opening Brief that it will "only apply VPF revenues to the Safety & Risk

[210] D.25-06-002 at 17.

programs where both the 2026 MWC category and (Maintenance Activity Type) code level of the proposed program are above authorized imputed amounts with the exclusion of balancing accounts involving the return of unused funds to customers."[211]

The Commission agrees with TURN that PG&E's response to D.25-06-002 requirements that PG&E explain how VPF programs align with the "guiding principle of reducing upward pressure on rates" lacks depth or detail. PG&E is correct that D.25-06-002 does not specify what type of information is required in its response. However, PG&E is encouraged to provide more quantitative analysis and detail in future DCPP cost recovery applications making the case for how each VPF-funded program provides net benefit to ratepayers.

Additionally, the Commission concurs with PG&E's response to CARE, A4NR, and EPUC regarding when VPF funds must be spent on DCPP operating expenses. The 115 percent overspend threshold set in D.23-12-036 remains the controlling criteria on when VPF funds must support DCPP operating expenses. Evaluating PG&E's proposed 2026 DCPP VPF spending according to this principle, the Commission finds the proposed VPF programs comply with statute and previous Commission decisions.

Finally, the Commission accepts PG&E's response to CARE's concerns about specific VPF-funded programs. The Commission finds PG&E has provided sufficient detail about each of the programs and that they sufficiently comply with the purposes set in Pub. Util. Code Section 712.8(s).

[211] PG&E Opening Brief at 50.

PG&E's spending on VPF programs will be further analyzed in the independent auditor report ordered in D.24-12-033 evaluating PG&E's expenditures on projects identified in its first year report, and controls related to those expenditures, to ensure consistency and compliance with Pub. Util. Code Section 712.8(s). As stated in D.24-12-033, the auditor's report must attest to each of the requirements set forth in Pub. Util. Code Section 712.8(s), including whether PG&E received double-recovery for projects and/or expenditures detailed in its first spending plan and, in particular, how VPF expenditures are incremental to costs recorded in existing accounts authorized by Commission decisions. PG&E must file and serve on the parties the auditor's report by no later than June 1, 2026, in the applicable VPFs review proceeding, required under Ordering Paragraph 15 of D.23-12-036, a proceeding in which the Commission will review spending for Pub. Util. Code Section 712.8(s) compliance, including the prohibition against double recovery.

In conclusion, PG&E's request for approval of its VPF spending plan is approved. The VPFs collected by PG&E must be held in the VPFs Subaccount of the DCEOBA.

10. Compliance with Other Decisions

PG&E addressed in its application the compliance requirements established by D.23-12-036, D,24-12-033, and D.25-06-002 and how the application addressed these requirements.[212]

[212] PG&E Opening Brief at 55-58.

A4NR states in its Opening Brief that PG&E has not complied with D.24-12-033's requirement that PG&E "[p]rovide a detailed account of why PG&E did not seek government funding for the costs being requested to be recovered from ratepayers, or was otherwise unable to anticipate the need for the investments and activities at the time government funding was being requested" pertaining to costs in excess of $1 million.[213] Similarly, EPUC and CARE write that PG&E has not complied with CPUC directives to explain why it did not seek government funding for DCPP costs.[214,215] EPUC also states that PG&E has not complied with Pub. Util. Code Section 712.8(e)'s requirement that PG&E "track all costs associated with continued and extended operations with Diablo Canyon Units 1 and 2."[216] SBUA raises similar concerns about PG&E's transparency with DCPP costs in its 2026 application.

TURN states in its Opening Brief that PG&E failed to comply with Ordering Paragraph 3 in D.25-06-002 that PG&E provide information on recorded and authorized spending for individual MWCs, in which the Maintenance Activity Type is located, related to work funded by VPFs.[217] PG&E replied in Rebuttal Testimony that D.25-06-002 did not require PG&E to file the information in relation to its 2026 DWPP cost recovery application.[218]

[213] A4NR Opening Brief at 13.

[214] EPUC Opening Brief at 26.

[215] CARE Opening Brief at 20-21.

[216] EPUC Opening Brief at 27.

[217] TURN Opening Brief at 20-21.

[218] Ex. PG&E-03 at 6-19.

Upon review of the Application and party comments, the Commission concludes that PG&E's application complied with the requirements established by the Commission in D.23-12-036, D,24-12-033, and D.25-06-002. In particular, TURN's concerns are not convincing as D.25-06-002 does not specify in which application year PG&E must comply with the MWC reporting requirement.[219] By comparison, D.25-06-002 specifies PG&E must explain how its proposed VPF expenditures align with affordability principles "starting with the 2026 VPF spending plan."[220] Additionally, as discussed earlier, PG&E minimally complies with requirements in D.24-12-033 that it explain why it did not seek government funding for project costs in excess of $1 million requested for recovery from ratepayers, or was otherwise unable to anticipate the need for the investments and activities at the time government funding was being requested. In light of the additional requirement outlined in Section 6.1.2, PG&E will no longer be required to explain why it did not seek government funding for projects costs in excess of $1 million requested for recovery from ratepayers. Otherwise, the Commissions finds PG&E provided sufficient detail about its 2026 DCPP costs as required by statute.

Finally, PG&E complied with D.24-12-033 by disclosing its 2025 and forecast future Administrative and General (A&G) expenses.

11. Summary of Public Comment

Rule 1.18 allows any member of the public to submit written comment in any Commission proceeding using the "Public Comment" tab of the online

[219] D.25-06-002 at 42 (OP 3).

[220] D.25-06-002 at 17.

Docket Card for that proceeding on the Commission's website. Rule 1.18(b) requires that relevant written comment submitted in a proceeding be summarized in the final decision issued in that proceeding.

In this proceeding, 20 members of the public submitted comments opposing the requested rate increase.

12. Procedural Matters

This decision affirms all rulings made by the Administrative Law Judge and assigned Commissioner in this proceeding. All motions not ruled on are deemed denied.

13. Comments on Proposed Decision

The proposed decision of ALJ Jack Chang in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on November 20, 2025 byA4NR, CARE, CGNP, CUE, EPUC, PG&E, SBUA, SLOMP, TURN, and WEM, and reply comments were filed on November 25, 2025 by A4NR, CARE, CUE, PG&E, SBUA, TURN, and WEM.

We have carefully reviewed all comments and reply comments and made appropriate changes as warranted. Below, we describe some of these changes.

In response to comments on the proposed decision filed by A4NR, SBUA, TURN, and WEM, [221] we have added requirements in Section 6.1.2, Conclusion of Law 6, and Ordering Paragraph 6 that PG&E disclose whenever any DCPP costs

[221] TURN Comments, November 20, 2025, at 11-14; WEM Comments at 1-8; SBUA Comments at 2-3; A4NR Comments at 2-3.

previously proposed as transition and license renewal costs are subsequently recategorized and proposed for recovery in a future DCPP forecast proceeding, along with explanations for why those costs were originally proposed as transition and license renewal costs and why those costs are now eligible for recovery as a cost for DCPP.

In response to PG&E comments, the decision specifies in Section 6.3.2 that forecasted DCPP RA substitution capacity costs decreased due to the updated outage schedule provided in PG&E's Fall Update in addition to the decrease in system RA MPB.[222]

In response to PG&E comments, the decision clarifies that Conclusion of Law 13 applies to the use of the RA MPB specifically for calculating the RA substitution capacity cost forecast.[223]

In response to PG&E comments, the decision corrects a typo in Section 6.5 clarifying that the revised Energy Index MPB, and not the revised RA MPB, decreased the DCPP energy market revenue forecast.[224]

14. Assignment of Proceeding

Karen Douglas is the assigned Commissioner, and Jack Chang is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. D.23-12-036 specified what PG&E must include in its forecast DCPP extended operations cost application.

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[222] PG&E Comments at 6.

[223] PG&E Comments at 7.

[224] PG&E Comments at 6.

2. In compliance with D.23-12-036, PG&E timely filed its application for Commission review and approval of its forecasted costs covering the period starting from January 1 through December 31, 2026 to support DCPP extended operations.

3. Consistent with the Commission's directives in D.23-12-036, PG&E's application includes: (1) a forecast of costs of extended operations, (2) a forecast of market revenues for DCPP for the Record Period, and (3) a proposal to establish the DC NBC applicable to all Commission jurisdictional customers based on the forecasted net costs.

4. PG&E estimates $1,208.1 million for DCPP costs, statutory fees, and substitution capacity expenses, with an offsetting $842.676 million of CAISO net forecasted market revenue, for a net revenue requirement of $382.233 million.

5. PG&E's forecasted O&M expense of $726.245 million includes the base O&M expense, projects expense, nuclear fuel expense, and employee retention program expense.

6. There are no actual or known forecastable costs for NRC license renewal conditions or any DCISC recommendations during the Record Period.

7. PG&E provided a workable framework to distinguish transitional costs from extended operations costs.

8. PG&E properly followed the common practice in GRCs, as directed by D.23-12-036 and D.24-12-033, and presented summaries for projects over $1 million.

9. PG&E's request to recover $53.061 million in employee retention costs for the Record Period in the DC NBC is consistent with Pub. Util. Code Section 712.8(f)(2), D.22-12-005, Resolution E-5299, D.23-12-036, and D.24-09-002.

10. DCPP is a generation asset and the purpose of the Fixed Management Fee is to compensate PG&E shareholders for the risks associated with generation assets.

11. PG&E's liquidated damages funding calculation of $75 million is correct.

12. The CPI-U is an appropriate measure of U.S. cost growth and applies to the DCPP Fixed Management Fee.

13. Due to the decrease in the system RA MPB, the forecasted RA substitution capacity costs for the Record Period decreased from $160.837 million to $26.288 million in the Fall Update.

14. The use of PCIA benchmarks to calculate RA substitution cost is more transparent and aligns with the regulatory precedent.

15. Costs that are already attributed to the DWR Loan are considered incremental as they were needed to pay for the extension of the existing fuel cycle, whereas the nuclear fuel costs sought herein are outside of the window and part of ongoing operations during the extension and are necessary for the operation of the plant.

16. The treatment of nuclear fuel expense aligns with the Commission's historical treatment of nuclear fuel costs where these costs were recovered annually in rates through the ERRA Forecast proceeding.

17. The computation of netting the CAISO revenues is undisputed by the parties.

18. PG&E's VPF spending plan provides sufficient detail showing how the plan is consistent with Pub. Util. Code Section 712.8(s)(1) requirements.

19. There is already a public agency review process involving a semi-annual true-up and Advice Letter process established for reviewing transition costs recorded to the Diablo Canyon Transition and Relicensing Memorandum Account, and DWR and the Commission have the authority and capability of reviewing these expenses.

20. PG&E has revealed in the TLRES that it forecasted spending $1.487 billion in transition and license renewal spending forecast through 2026, which is $157 million more than the $1.4 billion allocated in the DWR loan dedicated to transitional and license renewal costs, after accounting for administrative costs that DWR is authorized to retain.

21. PG&E has stated that it is in the process of a reprioritization to ensure it fully utilizes the DWR loan without exceeding the loan amount.

Conclusions of Law

1. PG&E's 2026 DCPP extended operations revenue requirement of $382.233 million should be approved.

2. The approved costs should be reflected in statewide rates starting on January 1, 2026.

3. PG&E's request to recover $726.245 million in total O&M costs for the period January 1 to December 31, 2026, is reasonable.

4. PG&E's request to recover $53.061 million in employee retention costs for the Record Period in the DC NBC should be approved.

5. PG&E should be required to disclose in future DCPP cost recovery applications whenever any transition and license renewal costs that were part of the amounts included in the TLRES are proposed for recovery in any future DCPP forecast proceedings, along with explanations for why those costs were originally proposed as transition and license renewal costs and why those costs are now eligible for recovery in extended operations.

6. PG&E's request for $266.56 million in VPFs; $113.997 million in Fixed Management Fee, and $75 million to be recorded to the liquidated damages subaccount of the DCEOBA should be approved.

7. The use of a CPI-U-based escalator for fixed management fees is reasonable and appropriate.

8. PG&E's liquidated damages funding request of $75 million complies with Pub. Util. Code Section 712.8(g), is reasonable, and should be approved.

9. The CPI-U should be adopted as the methodology to forecast annual escalation in the DCPP Fixed Management Fee and should be used in future DCPP cost recovery applications to incrementally escalate the Fixed Management Fee approved in the previous year's DCPP application.

10. PG&E's RA substitution capacity cost forecast of $26.288 million for the extended operations period of January 1 through December 31, 2026 should be approved.

11. The use of the RA MPB for calculating RA substitution capacity cost is appropriate and should be approved.

12. PG&E's nuclear fuel cost forecast and straightline amortization proposal are reasonable, comply with Pub. Util. Code Sections 712.8(c)(1)(C), 712.8(h)(1)

and Commission decisions and resolutions interpreting those statutory sections, and should be approved.

13. PG&E's methodology to calculate forecast CAISO energy market revenues is reasonable and should be approved.

14. The IOUs' proposal for allocation of the DCPP extended operations cost is consistent with the direction provided in D.23-12-036 and should be approved.

15. PG&E's request for approval of its VPF spending plan should be approved.

16. All rulings issued by the assigned Commissioner and the assigned ALJ should be confirmed.

17. All motions not specifically addressed herein or previously addressed by the assigned Commissioner or ALJ, should be denied.

18. This application should be closed.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company is authorized to recover a revenue requirement of $382.233 million covering the extended operations costs from January 1 to December 31, 2026, which includes operations and maintenance costs; resource adequacy substitution capacity forecast; generation forecast and generation revenues forecast methodology and calculation; amortized fuel expense cost for fuel over the 2025 through 2030 period; and netting of California Independent System Operator revenues of the period of January 1 to December 31, 2026.

2. The methodology for calculation of the Diablo Canyon Power Plant nonbypassable charge and rate proposals by Pacific Gas and Electric Company (PG&E), Southern California Edison Company, and San Diego Gas and Electric Company, complies with Decision 23-12-036 and is adopted. Final rates should reflect the revenue requirement adopted in this decision, as updated by corrections identified in PG&E's reply comments on the Fall Update and updated balancing account balances that reflect recorded actuals through November 2025.

3. Pacific Gas and Electric Company's proposed volumetric performance fees spending plan for the January 1 to December 31, 2026 period is approved.

4. Pacific Gas and Electric Company's (PG&E's) methodology for escalating the annual Fixed Management Fee using the all-urban consumer price index is approved. We direct PG&E to use the same consumer price index methodology to adjust the Fixed Management Fee in future Diablo Canyon Power Plant (DCPP) cost recovery applications to incrementally escalate the Fixed Management Fee approved in the previous year's DCPP application.

5. Pacific Gas and Electric Company (PG&E) must disclose whenever any transition and license renewal costs that were part of the amounts detailed in the Transition and License Renewal Expenditure Summary in PG&E witness Brian Ketelsen's sworn federal court affidavit are proposed for recovery in any future Diablo Canyon Power Plant (DCPP) forecast proceedings for DCPP extended operations, along with explanations for why those costs were originally proposed as transition and license renewal costs and why those costs are now eligible for recovery for extended operations.

6. Unless otherwise noted, Pacific Gas and Electric Company's testimony satisfies all the regulatory requirements set forth in Decisions 23-12-036, Decision 24-12-033, and Decision 25-06-002.

7. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company must file a Tier 1 Advice Letter and revised tariff sheets within 60 days of the issuance of this decision to implement this Decision.

8. Pacific Gas and Electric Company must provide Southern California Edison Company and San Diego Gas & Electric Company with the final revenue requirement for each of the respective utilities no later than Friday, December 12, 2025.

9. All rulings issued by the assigned Commissioner and the assigned Administrative Law Judge (ALJ) are affirmed; and all motions not specifically addressed herein or previously addressed by the assigned Commissioner or ALJ are denied.

10. Application 25-03-015 is closed.

This order is effective today.

Dated _____________________________, at San Francisco, California