



STATE OF CALIFORNIA

GAVIN NEWSOM, Governor **FILED**

PUBLIC UTILITIES COMMISSION

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Ratesetting

TO PARTIES OF RECORD IN APPLICATION 26-03-031:

This is the proposed decision of Administrative Law Judge Jack Chang. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's **December 3, 2026** Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

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

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, *ex parte* communications are prohibited pursuant to Rule 8.2(c)(4).

/s/ MICHELLE COOKE
Michelle Cooke
Chief Administrative Law Judge

MLC: smt

Attachment

Decision **PROPOSED DECISION OF ALJ CHANG** (Mailed 10/30/2026)

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, 2027, and for Approval of Planned Expenditure of 2027 Volumetric Performance Fees. (U39E)

Application 26-03-031

**DECISION ON PACIFIC GAS AND ELECTRIC COMPANY'S REVENUE
REQUIREMENT TO SUPPORT EXTENDED OPERATION OF DIABLO
CANYON POWER PLANT AND 2027 VOLUMETRIC
PERFORMANCE FEES PROPOSAL**

TABLE OF CONTENTS

<u>Title</u>	<u>Page</u>
DECISION ON PACIFIC GAS AND ELECTRIC COMPANY'S REVENUE REQUIREMENT TO SUPPORT EXTENDED OPERATION OF DIABLO CANYON POWER PLANT AND 2027 VOLUMETRIC PERFORMANCE FEES PROPOSAL.....	1
Summary	2
1. Regulatory Background	2
2. Procedural Background	5
2.1. Submission Date	6
3. PG&E's Revenue Requirement Request with the Fall Update	6
4. Issues Before the Commission	9
5. Burden of Proof and Evidentiary Standard	10
6. PG&E's Forecasted Cost and Requested Revenue Requirement.....	11
6.1. Operations and Maintenance Costs.....	11
6.1.1. PG&E's Forecasted O&M Costs.....	11
6.1.2. Transition and License Renewal Projects Costs Proposed for Recovery through Diablo Canyon Extended Operation Costs	13
6.1.3. Pressurized Water Reactor Owners Group Fees.....	17
6.1.4. Conclusion – O&M Costs	18
6.2. Working Cash Adjustment	19
6.3. Statutory Fees.....	20
6.3.1. Fixed Management Fees	20
6.3.2. Volumetric Performance Fees	22
6.3.3. Liquidated Damages Fund.....	23
6.4. RA Substitution Capacity Costs	25
6.4.1. Background.....	25
6.4.2. PG&E's Proposal.....	26
6.5. Nuclear Fuel Costs	28
6.6. PG&E's Generation and Generation Revenue Forecasts.....	29
6.6.1. PG&E's Methodology	29
6.6.2. Party Comments and Discussion	30
6.7. Netting of CAISO Revenues	32
7. Non-Bypassable Charge.....	33
7.1. Background and the IOUs' Joint Proposal	33
7.2. Party Positions	34
7.3. Discussion.....	34
8. Volumetric Performance Fees Spending Plan	35

TABLE OF CONTENTS

<u>Title</u>	<u>Page</u>
8.1. Background	36
8.2. Party Positions	41
8.3. Discussion.....	41
9. Compliance with Other Decisions.....	42
10. Summary of Public Comment.....	42
11. Procedural Matters	42
12. Comments on Proposed Decision	42
13. Assignment of Proceeding.....	43
Findings of Fact.....	43
Conclusions of Law	44
O R D E R	46

**DECISION ON PACIFIC GAS AND ELECTRIC COMPANY'S REVENUE
REQUIREMENT TO SUPPORT EXTENDED OPERATION OF DIABLO
CANYON POWER PLANT AND 2027 VOLUMETRIC
PERFORMANCE FEES PROPOSAL**

Summary

This decision approves Pacific Gas and Electric Company's (PG&E's) 2027 Diablo Canyon Power Plant extended operations revenue requirement of \$933.799 million. The revenue requirement is allocated to PG&E, Southern California Edison Company, and San Diego Gas & Electric Company using the allocation factors 45.22%, 45.22%, and 9.56%, 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) 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 DCPD extended operations are imprudent or unreasonable.²

Further, D.23-12-036 allocates the costs and benefits of extended DCPD 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 DCPD 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 DCPD extended operations costs, with subsequent true-up to actual costs and market revenues for the prior calendar year.³

D.23-12-036 directs that the annual DCPD proceeding should:

1. Determine the allocation of costs and benefits of DCPD 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) and among the LSEs in each large electrical corporation's territory, and should endeavor to provide all LSEs with allocations of DCPD's RA benefits for the upcoming

² D.23-12-036 at Ordering Paragraph (OP) 1.

³ D.23-12-036 at OP 1.

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 DCPD 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 DCPD 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.

D.25-12-007 approved PG&E's 2026 DCPD extended operations revenue requirement of \$382.233 million and adopted a consumer price index-based method of escalating the annual Fixed Management Fee.⁶ D.25-12-007 also required PG&E to 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 DCPD forecast proceedings for DCPD extended operations.⁷ Additionally, D.25-12-007 required PG&E to

⁴ D.23-12-036 at 104 and OP 9.

⁵ D.25-06-002 at 17.

⁶ D.25-12-007 at OP 4.

⁷ D.25-12-007 at OP 5.

explain why those costs were originally proposed as transition and license renewal costs and are now eligible for recovery for extended operations.⁸

2. Procedural Background

In compliance with D.23-12-036, on March 27, 2026, 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 DCPD from January through December 31, 2027 and for Approval of Planned Expenditure of 2027 Volumetric Performance Fees* (Application) and served associated testimony.

A prehearing conference was held on May 22, 2026, 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 June 16, 2026, the assigned Commissioner issued a Scoping Memo and Ruling (Scoping Memo).

PG&E submitted amended testimony on July 3, 2026.

The parties to this proceeding submitted testimony on July 16 and 17, 2026, followed by the submission of concurrent rebuttal testimony on August 14, 2026.

The parties filed their Joint Report of Meet and Confer and preliminary exhibit and witness list on August 28, 2026, which stated that evidentiary hearings would not be needed.

Opening briefs were filed by Alliance for Nuclear Responsibility (A4NR), the Public Advocates Office at the California Public Utilities Commission (Cal Advocates), Californians for Renewable Energy (CARE), Californians for Green Nuclear Power (CGNP), Coalition of California Utility Employees (CUE), SCE, Pacific Gas and Electric Company (PG&E), Women's Energy Matters (WEM), and The Utility Reform Network (TURN) on October 1, 2026, and reply briefs

⁸ D.25-12-007 at OP 5.

were filed by PG&E, Cal Advocates, CGNP, TURN, CUE, and WEM on October 22, 2026.

In accordance with the Scoping Memo, PG&E updated its prepared testimony on October 8, 2026, to include any updated forecast and recorded Diablo Canyon Extended Operations Balancing Account (DCEOBA) balances (Fall Update). Comments to the update were filed by CARE on October 19, 2026, and by A4NR, CGNP, PG&E, and WEM on October 20, 2026, and reply comments were filed by PG&E on October 27, 2026.

The assigned Administrative Law Judge (ALJ) issued a ruling admitting the public versions of updated testimony on October 28, 2026 and admitting under seal the confidential versions of testimony on October 29, 2026.

2.1. Submission Date

This matter was submitted on October 27, 2026 upon filing of reply comments on updated testimony.

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, 2027 (the Record Period) to support DCPD extended operations.

If approved, these forecasted costs will be reflected in statewide rates starting on January 1, 2027.

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 DCPD for the Record Period, (3) a proposal to establish the Diablo Canyon Non-bypassable Charge (DCNBC) applicable to all Commission-jurisdictional customers based on forecast net cost and applicable true-up amounts, and (4) proposals for spending the VPF collected in accordance

with California Public Utilities Code (Pub. Util. Code) Section 712.8(f)(5).⁹ PG&E also disclosed \$26 million in Diablo Canyon Transition and Relicensing Memorandum Account (DCTRMA) that it was proposing to reclassify.¹⁰

PG&E served its Fall Update on October 8, 2026. PG&E's Fall Update includes updated market and generation production information, and updated allocation of the statewide 2027 DCNBC applicable to the investor-owned utilities (IOUs). These updates are based on and consistent with updates to the Energy Index and RA MPBs issued by the Commission's Energy Division on October 1, 2026.¹¹

In the Fall Update, PG&E raised its net 2027 Diablo Canyon Extended Operations revenue requirement from the \$595 million forecast in A.26-03-031 to \$933.799 million.¹² In particular, PG&E reported that its forecasted 2026 California Independent System Operator (CAISO) Net Revenue, which is reflected in the DCEOBA, dropped by \$297 million to \$546 million compared to the amount forecasted in A.26-03-031.¹³ Additionally, PG&E's forecast of 2027 CAISO net revenue dropped by \$22.3 million from \$750.559 million originally forecast in A.26-03-031 to \$728.247 million in the Fall Update.¹⁴ PG&E's forecast of operations and maintenance (O&M) cost presented in its Opening Prepared Testimony increased by \$742,000 to \$780.456 million, its forecasted Administrative and General cost increased by \$1.766 million to \$155.384 million,

⁹ Exhibit (Ex.) PG&E-01 at 1-3.

¹⁰ Ex. PG&E-01 at 2-15 to 2-16.

¹¹ MPB Calculations at 1.

¹² Ex. PG&E-03 Table 1-3.

¹³ Ex. PG&E-03 at 13.

¹⁴ Ex. PG&E-03 Table 1-3.

its forecasted Management, Performance Fees, and Liquidated Damages cost increased by \$9.395 million to \$400.652 million, and its forecasted Resource Adequacy Substitution Capacity costs decreased by \$2.155 million to \$14.297 million.¹⁵ PG&E's forecasted VPF revenues grew from \$274.1 million to \$284 million due to non-O&M inflation for calendar year 2026, and its forecasted Franchise Fees and Uncollectibles grew by \$5.389 million to \$14.335 million.¹⁶

If authorized as proposed, the requested revenue requirement would be allocated to the IOUs approximately as follows: (1) PG&E, \$496.3 million; (2) SCE, \$352 million; and (3) SDG&E, \$82 million.¹⁷

PG&E estimates that the requested revenue requirement, if approved, would result in a system average bundled service rate increase by approximately 1.0 percent to approximately 32.9 cents per kWh when compared to the present system average bundled service rate of 32.6 cents per kWh.¹⁸ The system average rate for Direct Access (DA) and Community Choice Aggregation (CCA) customers would increase by approximately 1.5 percent to 24.0 cents per kWh, when compared to the present system average rate for DA and CCA customers of 23.64 cents per kWh.¹⁹ According to PG&E's Fall Update, SCE's total system average bundled service rate would decrease by 1.0 percent to 29.9 centers per kWh.²⁰ It is unclear whether the projected SCE total system average bundled

¹⁵ Ex. PG&E-03 Table 1-3.

¹⁶ Ex. PG&E-03 at 5.

¹⁷ Ex. PG&E-03 at 17.

¹⁸ Ex. PG&E-03 at 19.

¹⁹ Ex. PG&E-03 at 19.

²⁰ Ex. PG&E-03 Table 10-9.

service rate is noted correctly in the Fall Update. SDG&E's system total average bundled service rate would increase by 0.7 percent to 39.5 cents per kWh.²¹

4. Issues Before the Commission

Pursuant to the Scoping Memo, dated June 16, 2026, the issues to be determined in this proceeding are as follows:

1. Whether PG&E's forecast cost of operations and requested net revenue requirement of \$595 million over the Record Period for DCPD 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. Resource Adequacy (RA) substitution capacity forecast and true-up costs;
 - c. Operating expenses that would be amortized through 2030 (e.g., nuclear fuel procurement);
 - d. Netting of California Independent System Operator (CAISO) revenues for the period from January 1, 2027, to December 31, 2027;
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 volumetric performance fees (VPFs) spending plan for the January 1, 2027 to December 31, 2027 period complies with Pub. Util. Code Section 712.8(s)(1) and all Commission requirements and should be approved.
4. Whether it is reasonable for PG&E to reclassify \$26 million in costs originally included in the Diablo Canyon Transition and Relicensing Memorandum Account to the Diablo Canyon Extended Operations Balancing Account, as described in PG&E's testimony;

²¹ Ex. PG&E-03 Table 10-12.

5. Whether PG&E's testimony satisfies all the regulatory requirements set forth, including D.23-12-036, D.24-12-033, D.25-06-002, and D.25-12-007.

The Scoping Memo determined that the following issues are out of scope:

1. 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 and D.25-06-002.
2. Whether the Commission should review historical DCPD costs.
3. Whether the Commission should modify the escalation method for Fixed Management Fees adopted in D.25-12-007.
4. Whether the operation of DCPD is cost effective.

5. Burden of Proof and Evidentiary Standard

Pub. Util. Code Section 451 requires that “all 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.²² 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.’”²³

²² D.19-05-020 at 7; D.15-11-021 at 8-9; D.14-08-032 at 17.

²³ 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 2027 DCPD extended operations net revenue requirement. 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 \$637.945 million in O&M costs excluding nuclear fuel procurement for the period January 1 to December 31, 2027.

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

In its Application, as modified by the Fall Update, PG&E requests the Commission adopt its forecast for total extended operations and maintenance expense, excluding nuclear fuel procurement, of \$637.945 million for the period January 1 to December 31, 2027.²⁴ PG&E's forecasted O&M expenses are comprised of 12 Major Work Categories (MWC) – manage environmental operations, manage DCPD business, operate DCPD plant, loss prevention, maintain DCPD plant assets, enhance DCPD personnel performance, maintain DCPD plant configuration, procure DCPD materials and services, provide nuclear support, informational technology forecast, manage fleet services, and manage balancing account processes.²⁵

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

²⁴ Ex. PG&E-03 Table 1.

²⁵ Ex. PG&E-01 at 2-18 to 2-28.

recommendations and conditions from the DCISC and NRC.”²⁶ PG&E reports that there are no actual or known forecastable costs for NRC license renewal conditions or any DCISC recommendations during the record period.²⁷

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.²⁸ 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	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	Total Period Forecast
O&M Expense	\$6,121	\$298,484	\$449,286	\$482,664	\$1,236,555
Projects Expense	\$2,197	\$63,030	\$60,496	\$99,713	\$225,436
Fuel Administration	N/A	N/A	\$1,092	\$636	\$1,728
Retention Program Expense	\$55,277	\$56,210	\$53,061	\$54,932	\$219,480
Total O&M Expense (excluding nuclear fuel procurement)	\$63,596	\$417,724	\$563,934	\$637,945	\$1,683,199

PG&E states that the first component, the base O&M expense, covers direct labor costs, material, contract, and other costs for January 1, 2027 to December 31,

²⁶ D.23-12-036 at 60.

²⁷ Ex. PG&E-01 at 2-2.

²⁸ A.26-03-031 at 8.

2027, excluding project costs, retention program expense, and fuel administration and fuel procurement amortization.²⁹

**6.1.2. Transition and License Renewal Projects
Costs Proposed for Recovery through Diablo
Canyon Extended Operation Costs**

As ordered by D.25-12-007 Ordering Paragraph 5, PG&E discloses in its Application \$26 million in costs originally identified in its Transition and License Renewal Expenditure Summary (TLRES) that PG&E is now seeking recovery of through the DCEOBA. PG&E discloses three projects originally identified in the TLRES that are now reclassified to the DCEOBA – feed-water heaters, with a total cost of \$14.1 million reclassified due to supply chain challenges; control room ventilation system condenser replacement projects, with a total cost of \$11.5 million reclassified based on advanced planning and scope definition; and intake bar rack replacement, with a total cost of \$0.4 million reclassified based on resource planning and availability reprioritization.³⁰ PG&E states that the costs were reclassified after they were no longer expected to be completed before January 1, 2027.³¹ D.24-12-033 established a framework in which projects that are not required by PG&E's Nuclear Regulatory Commission License Renewal Application and are expected to be placed in service on or after January 1, 2027 are categorized as extended operations costs recoverable through customer rates, rather than through the \$1.4 billion Department of Water Resources loan dedicated to DCPD license renewal costs.³²

²⁹ Ex. PG&E-01 at 2-2 to 2-3.

³⁰ Ex. PG&E-01 Table 2-3.

³¹ Ex. PG&E-01 at 2-15.

³² D.24-12-033 at 18.

CARE states that it is not reasonable to allow PG&E to shift \$26 million in costs that were DCTRMA costs to the DCEOBA.³³ In particular, CARE argues that the \$14.1 million requested by PG&E for feedwater heater replacement was intended to be financed by the DWR loan but that “PG&E unilaterally chose to reclassify it for ratepayer funding.”³⁴ CARE also argues that the DCISC identified the feedwater heater replacements “as necessary for extended operations in 2022” and that the feedwater heaters will only have 23 months of useful life after replacement based on the current operational timeline for DCP. ³⁵ CARE states that requested funding for the CRVS condenser replacement and the fuel transfer cart and upender upgrade should be denied because both projects were already canceled in PG&E’s 2020 GRC application.³⁶ CARE also states that Pub. Util. Code Section 718(c)(i)(C) prohibits PG&E from recovering from ratepayers costs incurred to ensure reliability during DCP’s extended operations.³⁷

A4NR recommends disallowance of the requested funds for feedwater heater replacement, stating that PG&E will have enough spare feedwater heaters if any of its existing feedwater heaters fail and that PG&E should have anticipated the need for replacement feedwater heaters.³⁸ A4NR also recommends disallowance of the requested funds for CRVS condensers replacement stating that the repair was already recommended in a 2023 report as a “top tier priority project” and that its reprioritization “exploited PG&E’s

³³ Ex. CARE-1 at 6.

³⁴ Ex. CARE-1 at 6.

³⁵ Ex. CARE-1 at 6.

³⁶ Ex. CARE-1 at 8-9, CARE Reply Brief at 5.

³⁷ CARE Reply Brief at 5.

³⁸ Ex. A4NR-1 at 18-19, A4NR Reply Brief at 3-5.

completion date criterion for DCTRMA by making an unreasonable schedule adjustment to avoid the statutory requirement.”³⁹ Finally, A4NR recommends disallowance of the requested funds for the intake bar rack replacement due to “[t]he absence of any information in PG&E’s Testimony or workpapers, beyond calling the present bar racks corroded, to justify the need for replacement prior to 2030.”⁴⁰

A4NR and WEM state that PG&E should not be allowed to recover feedwater heater replacement costs as the units could remain unused until after DCP’s 2030 retirement date.⁴¹

PG&E responds to A4NR’s statements by highlighting that the feedwater heaters are not interchangeable “as each unit’s feedwater heaters have unique design requirements.”⁴² PG&E also states that the delay in delivery of six feedwater heaters until 2027 resulted from a final fabrication schedule that identified the six feedwater heaters would not be delivered until 2027.⁴³ PG&E states that the CRVS condensers replacement was rescheduled to 2027 because “[a]s engineering and implementation planning progressed, PG&E identified additional scope, testing requirements, procurement planning, vendor coordination efforts, and NRC-related design considerations that extended the project’s anticipation completion date to the third quarter of 2027.”⁴⁴ PG&E also states that projects “were cancelled in the 2020 GRC because they were

³⁹ Ex. A4NR-1 at 22.

⁴⁰ Ex. A4NR-1 at 25.

⁴¹ A4NR Opening Brief at 7, WEM Reply Brief at 6.

⁴² Ex. PG&E-2 at 2-4.

⁴³ Ex. PG&E-2 at 2-5.

⁴⁴ PG&E Opening Brief at 42.

unnecessary under the then remaining operational life of DCP" and that "[t]he enactment of SB 846 and the Commission's approval of extended operations fundamentally changed that analysis."⁴⁵ PG&E states that the anticipated schedule for replacing the intake bar rack was moved from 2026 to 2027 "because PG&E was required to prioritize numerous projects competing for limited resources and implementation opportunities."⁴⁶ PG&E also states that "[c]ompleting the project in 2027 remains necessary and prudent to address documented condition concerns, maintain consistency with the station's established design, and support plan reliability."⁴⁷

The Commission is satisfied with PG&E's explanation regarding the costs it originally classified as transition and licensee renewal expenses that it is now seeking recovery from the DCEOBA. The Commission finds that PG&E has demonstrated that the feedwater heaters that it seeks replacement funds for are not interchangeable and that delivery of the six feedwater heaters was delayed for reasons outside of PG&E's control. The Commission also agrees with PG&E that a previous GRC's determination regarding the CRVS condensers replacement has no bearing on this application. The Commission also finds satisfactory PG&E's explanation for why it rescheduled the intake bar rack replacement. Finally, the Commission disagrees with CARE's argument that Pub. Util. Code Section 718(c)(i)(C) prohibits PG&E from using ratepayer funds to recover costs incurred to ensure reliability during DCP's extended operations. Pub. Util. Code Section 718(c)(i)(C) specifically prohibits PG&E from using ratepayer funds to recover costs "in preparation for extended operations," not to

⁴⁵ PG&E Opening Brief at 11.

⁴⁶ PG&E Opening Brief at 44.

⁴⁷ PG&E Opening Brief at 44.

ensure reliability during extended operations. Accordingly, the Commission approves the \$26 million in costs originally identified in PG&E's TLRES that PG&E is now seeking recovery of through the DCEOBA.

6.1.3. Pressurized Water Reactor Owners Group Fees

PG&E states that the \$49.015 million in O&M expenses titled MWC BV – Maintain DCCP Plant Configuration includes dues to the Pressurized Water Reactor Owners Group (PWROG). In a response to a TURN data request, PG&E stated that its 2027 O&M forecast includes \$807,760 in PWROG dues.⁴⁸ TURN states that Assembly Bill (AB) 1167 requires the Commission to disallow recovery of any proposed expenditures that support “political influence activities” as defined by AB 1167.⁴⁹ According to TURN, PWROG activities are considered political influence activities under AB 1167, and the PWROG dues should not be collected in rates.⁵⁰ Specifically, TURN states that “PWROG engages in a wide array of advocacy activities at the (U.S. Nuclear Regulatory Commission) designed to modify existing rules and practices.”⁵¹ TURN also asks the Commission to clearly state that trade association dues for the World Nuclear Association are categorically excluded from ratepayer recovery.⁵²

PG&E responds that “PWROG’s activities consist of technical, operational, and regulatory-compliance work directly related to the safe and reliable operations of nuclear facilities, and fall within multiple statutory exclusions to

⁴⁸ Ex. TURN-02 PG&E Response to TURN Data Request 1, Question 9.

⁴⁹ Pub. Util. Code Section 748.3 (a)(6)(A).

⁵⁰ TURN Opening Brief at 6.

⁵¹ TURN Opening Brief at 5.

⁵² TURN Reply Brief at 6.

‘political influence activity’ in Pub. Util. Code § 748.3(a)(6)(B).”⁵³ PG&E also withdraws its request to recover World Nuclear Association dues.⁵⁴

AB 1167 exempts certain activities from the prohibition against ratepayer recovery for political influence activities, including “an activity that is directly and necessarily related to appearances before regulatory or other governmental bodies in connection with the utility’s existing or proposed operations of the utility’s regulated system.”⁵⁵ PG&E’s testimony demonstrates that past PWROG activities may qualify for this or other exemptions. This showing is sufficient to allow PG&E to recover in rates forecasted costs associated with PG&E’s PWROG membership.

The Commission is not, however, predetermining whether the 2027 PWROG activities are exempt. As part of its true-up advice letter filing for the record period, PG&E is directed to detail the PWROG activities paid for with ratepayer funds and how such activities qualify for an exemption. Specifically, as to Pub. Util. Code Section 748.3(a)(6)(B)(i), PG&E must demonstrate that the activities are “necessarily related to” DCP. If the Commission finds that any such ratepayer funded activities constitute non-exempt political influence activities, any costs associated with such activities may be disallowed.

6.1.4. Conclusion – O&M Costs

Upon consideration and based on the discussion presented in Section 6.1 of this decision, and subject to the true-up requirements imposed on payments related to PWROG activities, the Commission finds that PG&E’s forecasted O&M

⁵³ PG&E Opening Brief at 21.

⁵⁴ PG&E Opening Brief at 21-22.

⁵⁵ Pub. Util. Code Section 748.3 (a)(6)(B)(i).

costs comply with the applicable statute and Commission orders, are reasonable, and should be approved.

6.2. Working Cash Adjustment

PG&E forecasts refunding approximately \$1.477 million in working cash to customers for the 2027 operational year.⁵⁶ PG&E explains that working cash is composed of the amounts used to pay operating expenses in advance of receiving customer payments and is forecasted using a revenue lag comprised of market revenue from the CAISO as well as the IOUs' share of the revenue requirement.⁵⁷

Cal Advocates states that PG&E should refund ratepayers \$3.3 million in working cash based on PG&E's authorized cost of capital of 7.61%.⁵⁸ Cal Advocates argues that Pub. Util. Code Section 712.8(h)(1) requires that all DCPD costs be recovered as an operating expense and not be eligible for inclusion in the operator's rate base.⁵⁹ Cal Advocates also states that ratepayers already provide working cash to meet PG&E's requirements and PG&E does not need investors to supply any working cash. Cal Advocates concludes: "Thus, PG&E's working cash adjustment is a proposed refund to ratepayers as compensation for the cash retention that results from PG&E's collection of revenues in advance of its payment of 2027 DCPD expenses."⁶⁰ PG&E responds that Pub. Util. Code Section 712.8(h)(1) states that DCPD costs are not eligible for inclusion in the rate base

⁵⁶ Ex. PG&E-03 at 5.

⁵⁷ Ex. PG&E-01 at 4-5.

⁵⁸ Cal Advocates Opening Brief at 6-7.

⁵⁹ Cal Advocates Opening Brief at 7, Cal Advocates Reply Brief at 2-3.

⁶⁰ Cal Advocates Opening Brief at 7.

and thus “there is no investor financing to refund and no rate base adjustment as the rate base does not exist.”⁶¹

The Commission agrees with PG&E that Pub. Util. Code Section 712.8(h)(1) states that DCPD costs are not eligible for inclusion in the rate base and that the working cash refund does not constitute an adjustment to rate base. Accordingly, this decision approves PG&E’s refund of \$1.477 million in working cash.

6.3. Statutory Fees

The Commission approves the following statutory fees authorized by SB 846 and requested by PG&E for the extended operations period of January 1, 2027 through December 31, 2027: (1) \$116.6 million in the Fixed Management Fee; (2) \$284 million in the VPF; and (3) associated VPF and Fixed Management Fee escalation factors.⁶²

6.3.1. Fixed Management Fees

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 operator could be held liable for.”⁶³ 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.”⁶⁴ 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

⁶¹ PG&E Opening Brief at 28.

⁶² Ex. PG&E-01 at 5-1.

⁶³ Pub. Util. Code § 712.8(f)(6).

⁶⁴ Pub. Util. Code § 712.8(f)(6).

DCNBC.⁶⁵ 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.⁶⁶ 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.”⁶⁷ D.25-12-007 revised the Fixed Management Fee escalation method authorized in D.24-12-033 and instead ordered PG&E to escalate the annual Fixed Management Fee in future DCPD cost recovery applications by using the all-urban consumer price index.⁶⁸

PG&E explains in its Application that the forecasted Fixed Management Fee for the 2027 extended operations year is the product of \$57 million for each DCPD unit multiplied by the 2027 annual escalation factor of 1.0278.⁶⁹ The Fall Update explains that PG&E lowered the 2027 Fixed Management revenue forecast to \$116.6 million due to a decrease in the year-over-year Consumer Price Index (CPI) inflation forecast for 2027 using the Standard & Poor’s (S&P) Q2 2026 Macro Financial Alternatives Forecast data series, compared to the CPI inflation forecast using the S&P Q4 2025 Macro Financial Alternatives Forecast data series that PG&E used to calculate the forecasted 2027 Fixed Management Fee in A.26-03-031.⁷⁰

CARE states that the 2027 Fixed Management Fee should be set at \$58.368 million per unit using the Long Forecast Model and notes that PG&E has

⁶⁵ D.23-12-036 at 67.

⁶⁶ D.24-12-033 at 25.

⁶⁷ Pub. Util. Code 712.8 (h)(1)

⁶⁸ D.25-12-007 Ordering Paragraph 4.

⁶⁹ Ex. PG&E-01 at 5-2.

⁷⁰ Ex. PG&E-03 at 5.

adopted the same CPI-U escalation factor in its Fall Update.⁷¹ No party opposed PG&E's method for escalating the Fixed Management Fee for the 2027 extended operations year.

The Commission approves PG&E's fixed management fees for the 2027 extended operations year in the amount of \$116.6 million estimated using the methodology approved by the Commission in previous DCPD cost forecast applications.

6.3.2. Volumetric Performance Fees

Pub. Util. Code Section 712.8(f)(5) established VPFs for recovery in rates for DCPD "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 liable for."⁷² 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 DCPD 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 six dollars and fifty cents (\$6.50), in 2022 dollars, to be borne by customers in the service territory of the operator."⁷³ As with 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."⁷⁴

⁷¹ CARE Reply Brief at 10.

⁷² Pub. Util. Code Section 712.8(f)(6).

⁷³ Pub. Util. Code Section 712.8(f)(6).

⁷⁴ Pub. Util. Code Section 712.8(f)(6).

PG&E requests the Commission's approval to recover a total combined VPF for DCPD Units 1 and 2 of \$284 million for the Record Period.⁷⁵ PG&E also requests the Commission's approval of the proposed 2027 VPF cumulative escalation rate of 1.194, explaining it is the product of the weighted average cumulative PG&E labor expense escalation rate and the weighted average cumulative non-labor O&M expense escalation rate.⁷⁶

No party opposed PG&E's proposed VPF escalation rate.

The Commission approves PG&E's proposed VPF escalation rate of 1.194.

This decision considers PG&E's proposed VPF spending plan below in Section 8.

6.3.3. Liquidated Damages Fund

PG&E requests no funding for the Liquidated Damages subaccount, explaining that the authorized funding of \$300 million will be fully recovered by December 31, 2026.⁷⁷

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

⁷⁵ Ex. PG&E-03 at 5 to 6.

⁷⁶ Ex. PG&E-01 at 5-5, Ex. PG&E-03 at 5 to 6.

⁷⁷ Ex. PG&E-01 at 5-6.

resulting from an unplanned outage at DCPD 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.

No intervenor objected to PG&E's request of \$0 for the fund.

CARE states that PG&E should use accrued interest in the liquidated damages account to lower its revenue requirement, stating that "SB 846 does not authorize PG&E to retain any interest payments on the account."⁷⁸ PG&E responds that Pub. Util. Code Section 712.8 (g), (i), and (f) only allow disbursement of funds from the Liquidated Damages Subaccount "for reasonable replacement power costs during unplanned outage periods only, and remaining funds from the subaccount will be returned to customers in PG&E's service

⁷⁸ CARE Opening Brief at 25, CARE Reply Brief at 10-11.

territory in a manner to be determined by the Commission.”⁷⁹ CGNP states that reduction of the DCPD revenue requirement is not a permitted use of DCPD Liquidated Damages Subaccount interest.⁸⁰

The Commission agrees with PG&E that Pub. Util. Code Section 712.8(g), (i), and(f) only allow funds from the Liquidated Damages Subaccount to be used for reasonable replacement power costs during unplanned outage periods only. Accordingly, PG&E’s liquidated damages funding request of \$0 complies with the statute, is reasonable and should be approved, and no interest from the Liquidated Damages Subaccount shall be used to lower DCPD’s revenue requirement.

6.4. RA Substitution Capacity Costs

6.4.1. 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 DCPD units are on planned outages.⁸¹ 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 administrative and procurement costs associated with meeting DCPD’s substitution RA capacity obligations, including associated penalties and costs borne by non-DCPD resources.⁸²

D.24-12-033 found that “the Commission has already determined that the use of the RA MPB is appropriate. The use of Power Charge Indifference

⁷⁹ PG&E Opening Brief at 15.

⁸⁰ CGNP Reply Brief at 4.

⁸¹ D.23-12-036 at 86-87.

⁸² D.23-12-036 at 87.

Adjustment (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.”⁸³ Additionally, D.25-06-049 established a new methodology for calculating the RA MPB authorized in D.24-12-033 to calculate DCPD 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.⁸⁴ 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.⁸⁵

6.4.2. 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 capacity is then multiplied by a market reference price to estimate the total procurement costs for meeting DCPD’s RA substitution capacity obligations.⁸⁶

PG&E uses the outage and curtailment schedules from the generation forecast and multiplies that amount by the 2026 PCIA system RA MPB, similar to the practice used in the ERRA Forecast proceeding.⁸⁷ Consistent with traditional ERRA Forecast modeling practices, PG&E will true-up the 2026 substitution

⁸³ D.24-12-033 at 32.

⁸⁴ D.25-06-049 OP 1.

⁸⁵ D.25-06-049 OP 1.

⁸⁶ Ex. PG&E-01 at 3-4.

⁸⁷ Ex. PG&E-01 at 3-4.

capacity cost to reflect the final 2026 PCIA system RA MPB and update the DCPD RA substitution capacity cost forecast in the Fall using the forecast 2026 PCIA system RA MPB, unless otherwise directed by the Commission.⁸⁸ 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-DCPD resources within PG&E's generation portfolio.⁸⁹

As a result, PG&E seeks recovery from ratepayers of forecast RA Substitution Capacity Costs of \$14.297 million for 2027 as shown in Table 2. Due to the decrease in the system RA MPB, the forecasted RA substitution capacity costs decreased from \$16.5 million originally forecast in A.26-03-031.⁹⁰

Table 2: RA Substitution Capacity Cost Forecast

Year	Total
2024	\$16,340,100
2025	\$193,800,800
2026	\$26,288,000
2027	\$14,296,964
Total	\$250,725,864

No party opposed PG&E's forecast of RA substitution capacity costs.

PG&E's RA substitution capacity cost forecast of \$14.297 million for the extended operations period of January 1 through December 31, 2027 is approved.⁹¹

⁸⁸ Ex. PG&E-01 at 3-4.

⁸⁹ Ex. PG&E-01 at 3-4 to 3-5.

⁹⁰ Ex. PG&E-03 at 27.

⁹¹ Ex. PG&E-01 Table 3-1.

6.5. Nuclear Fuel Costs

PG&E requests that the Commission adopt its nuclear fuel amortization forecast of \$118.5 million for 2027.⁹² 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.⁹³

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.⁹⁴ 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.⁹⁵

No party objected to PG&E's method for recovering nuclear fuel expenses over the 2025-2030 period.

The Commission determines that PG&E's nuclear fuel cost forecast and straightline amortization proposal are reasonable, comply with Pub. Util. Code Sections 712.8(c)(1)(C) and 712.8(h)(1), and Commission decisions and resolutions interpreting those statutory sections, and are approved.

⁹² Ex. PG&E-01 at 2-35.

⁹³ Ex. PG&E-01 at 2-35 to 2-36.

⁹⁴ Ex. PG&E-01 at 2-37.

⁹⁵ Ex. PG&E-01 at 2-37.

6.6. 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 \$728.247 million in 2027 revenues.⁹⁶

6.6.1. 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 ERRR forecast proceeding, using a portfolio weighting factor calculation based on actual DCPD CAISO generation and revenue data as opposed to the entire PCIA-eligible portfolio.⁹⁷

PG&E updated the market reference price calculation in the Fall Update using the latest Platts North of Path-15 (NP-15) price curves. PG&E's forecast of CAISO energy market revenues is as follows:

Table 3: DCPD 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
2027	18,288	39.82	728,247

⁹⁶ Ex. PG&E-01 at 9-3.

⁹⁷ Ex. PG&E-01 at 6-2.

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

PG&E explains that the primary driver for PG&E's lower 2027 record period CAISO market revenue forecast is the change attributable to the 2026 end-of-year DCEOBA balance, which is forecast to be undercollected due to lower recorded CAISO market revenues compared to the 2026 forecast CAISO market revenues.⁹⁸

6.6.2. Party Comments and Discussion

WEM states that PG&E's DCPD CAISO revenue forecasts have consistently been overestimated both in their initial applications and Fall Updates and that the Commission should focus on the actual CAISO revenues recorded for each forecast year.⁹⁹ WEM also proposes that the MPB used to forecast CAISO market revenues for DCPD extended operations should be capped at \$36 per megawatt-hour (MWh).¹⁰⁰

A4NR notes the higher 2027 DCPD net revenue requirement forecast in the Fall Update and suggests the Commission "give careful consideration to the historical record and the opportunity costs incurred" as it "weighs whether and how to structure a 2027 examination of Diablo Canyon cost-effectiveness."¹⁰¹ CARE states that VPF subaccount funds should be used to offset DCPD extended operation costs because the forecasted 2027 DCPD costs are more than 15% over the net revenue requirement approved by D.25-12-007.¹⁰² CGNP states that even

⁹⁸ PG&E Reply Brief at 2.

⁹⁹ WEM Opening Comments on PG&E Fall Update at 2-4, WEM Reply Brief at 4.

¹⁰⁰ WEM Reply Brief at 5.

¹⁰¹ A4NR Opening Comments on PG&E Fall Update at 3.

¹⁰² CARE Opening Comments on PG&E Fall Update at 5-6, CARE Reply Brief at 13-17.

with the lower forecasted CAISO revenue, DCPD “is still an incredible bargain for ratepayers and the environment because DCPD's generation is both clean and firm.”¹⁰³ Finally, PG&E states that the 15% trigger for VPF funds applies only to situations where the actual recorded costs exceed approved forecast costs by 15% for a given record period.¹⁰⁴

Upon review of PG&E's request and party comments, the Commission determines that PG&E has forecasted 2027 DCPD's CAISO revenues in a manner that is consistent with prior Commission decisions, prior DCPD forecast proceedings, and the method used in the ERRR proceedings.¹⁰⁵ Also, the Commission does not adopt CARE's proposal to use VPF subaccount funds to offset DCPD extended operations costs as D.23-12-036 only required PG&E to use VPF fees to offset actual recorded costs more than 15% above PG&E's approved forecasted costs.¹⁰⁶ The Commission does not adopt WEM's proposed \$36/MWh cap for the MPB used to calculate CAISO market revenues for extended DCPD operations as WEM does not offer any calculation or other justification for the cap. Accordingly, the Commission finds PG&E's forecasted CAISO energy market revenues reasonable and approves them as adjusted for the corrected 2027 CAISO revenue amount.

¹⁰³ CGNP Opening Comments on PG&E Fall Update at 3.

¹⁰⁴ PG&E Reply Comments on Fall Update at 4.

¹⁰⁵ D.23-06-006 Appendix B, D.25-12-007 Conclusion of Law 13.

¹⁰⁶ D.23-12-036 at 110-111.

6.7. Netting of CAISO Revenues

PG&E requests that the Commission approve the consolidated net revenue requirement of \$933.799 million that will be used to allocate costs to the three large IOUs and will be the basis for setting rates.¹⁰⁷

In its Fall Update, PG&E consolidates PG&E's Diablo Canyon Extended Operations cost updates, DCPD Electric Generation Revenue Forecast Update, VPF Update, and the RA Substitution Cost Forecast. 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.

CARE stated that \$239.655 million of the net operating revenue requirement should be offset by VPF funds because the forecasted 2027 DCPD costs are more than 15% over the net revenue requirement approved by D.25-12-007.¹⁰⁸ No other party disputed the computation of netting the CAISO revenues. WEM also proposes that VPF funds be used to offset DCPD's revenue requirement.¹⁰⁹

As stated in the previous section, the Commission does not adopt CARE's proposal to use VPF subaccount funds to offset DCPD extended operations costs as D.23-12-036 only required PG&E to use VPF fees to offset actual recorded costs more than 15% above PG&E's approved forecasted costs.¹¹⁰ Upon review, a consolidated net revenue requirement of \$933.799 million is approved.

¹⁰⁷ Ex. PG&E-03 at 1.

¹⁰⁸ CARE Opening Comments on PG&E Fall Update at 5-6.

¹⁰⁹ WEM Reply Brief at 6.

¹¹⁰ D.23-12-036 at 110-111.

7. Non-Bypassable Charge

The Commission finds that the IOUs' proposal for allocation of the DCPD 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 DCPD extended operations costs.¹¹¹ The Commission required PG&E, SCE, and SDG&E "to provide joint testimony proposing an allocation among themselves of the statutorily defined [DCPD] 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 DCPD Extended Operations Cost Forecast application proceedings[.]"¹¹² In compliance with the requirements, the IOUs, jointly, presented their proposed allocation of the DCPD extended operations costs and the DCNBC rates applicable to each utility's customers.

The IOUs propose allocating the DCPD extended operations costs using a 12-month Coincident Peak (12-CP) load forecast, as required by D.23-12-036.¹¹³ They utilize the California Energy Commission's (CEC) peak load forecast developed for use in the Commission's RA program.¹¹⁴ Then, the utilities

¹¹¹ D.23-12-036 at 138-139, OP 14.

¹¹² D.23-12-036 at OP 7.

¹¹³ D.23-12-036 at COL 30, OP 14.

¹¹⁴ Ex. PG&E-01 at 10-3.

develop allocation factors by developing a percentage that each utility contributes to the total calculated forecast peak load.¹¹⁵ The IOUs updated the allocation of DCPD extended operations costs based on the more recent 2025 CEC 12-CP load forecast in the Fall Update, as shown below.¹¹⁶

Table 4: 12-CP Load Allocation Factors

IOU	MW	Percent
PG&E	175,494	45.22
SCE	175,514	45.22
SDG&E	37,107	9.56
Total	388,115	100.00

7.2. Party Positions

A4NR argues in its Opening Brief that the non-bypassable charge should be recalculated to reflect \$26.068 million in disallowances related to feedwater heater replacement, CRVS condenser replacement, and intake bar rack replacement.¹¹⁷

7.3. Discussion

In D.23-12-036, the Commission established a two-step process for allocating net statewide DCPD extended operations costs to the LSEs in each IOU service area. The first step involves allocation of DCPD 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 DCPD operating, it

¹¹⁵ Ex. PG&E-01 at 10-4.

¹¹⁶ Ex. PG&E-03 Table 10-2.

¹¹⁷ A4NR Opening Brief at 6.

follows that allocating the costs of those extended operations based on an IOU's share of a [12-CP] is fair and equitable."¹¹⁸

The second step in the process established in D.23-12-036 allocates each IOU's DCPD 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 DCPD extended operations costs within each IOU's territory."¹¹⁹

The Commission concludes that the IOUs' proposed methodology and rate design for allocating the DCPD 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. 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.

¹¹⁸ D.23-12-036 at 73-74.

¹¹⁹ D.23-12-036 at 75.

8.1. Background

Pub. Util. Code Section 712.8(s) provides the following guidance regarding the spending of DCPV 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, 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.¹²⁰ 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 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."¹²¹ 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 DCPD 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)]."¹²²

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.¹²³ 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

¹²⁰ D.23-12-036 at OP 15.

¹²¹ D.23-12-036 at 110-111.

¹²² D.23-12-036 at OP 60.

¹²³ Ex. PG&E-01 at 7-1.

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.¹²⁴

The total forecast for the VPFs collected in 2027 is \$284 million. The electricity generation forecast included in PG&E's Fall Update increased the VPF amount from \$274.1 million originally forecast in the Application.¹²⁵ The proposal includes the following programs.

1. Power Generation (PG): Asset Management, Inspection, and Maintenance (\$22.1 – 32.9 million) aims to accelerate identification of asset condition and risk across the entire system of water conveyances and power facilities.
2. PG: Communications (\$0.2 – 0.3 million) expands PG&E's public outreach beyond its existing K-8 hydro safety brochures to deliver broader communications about safety, renewable generation, and PG&E's operations.
3. PG: Workforce Safety Initiatives (\$0.4 – 1.0 million) continues implementation of Incident Management Teams who respond to employee-led workforce safety improvements, develop PG&E's Safety Culture, and enhance workforce safety procedures.
4. PG: Net Zero Carbon Energy Activities (\$1.3 – 8 million) aims to advance technical analyses for technologies aimed at reducing carbon dioxide emissions from PG&E-owned natural gas fired generation facilities.
5. PG: Renewable Energy Activities (\$1.3 to 2 million) accelerates early-stage development activities for large, utility-scale Battery Energy Storage System projects and other clean firm renewable generation projects.
6. EVA/EVB New Business (\$12.55 million) tracks expenses for the call center minutes for calls related to New Business

¹²⁴ Ex. PG&E-01 at 7-1.

¹²⁵ Ex. PG&E-04 at 7.

- & Work at the Request of Others by other service inquiries and applications.
7. Technology & System of Record (\$0 to \$13.5 million) includes map-based work execution, monitoring, and validating system enabling PG&E to maintain records and perform work.
 8. Overhead Inspections (\$31.93 million) identifies abnormal compelling conditions and other conditions that must be addressed for regulatory compliance reasons as well as third-party caused conditions that impact safety or reliability.
 9. Wildfire Situation Awareness and Forecast (WSAF): Wildfire Cameras (\$11.53 million) aims to mature the artificial intelligence capabilities of PG&E's overall early wildfire detection system.
 10. WSAF Asset Health and Performance Center (\$5.7 million) deploys and operates technologies and applications that provide data for real-time grid monitoring and analytics of asset health and performance.
 11. WSAF Meteorology Programs (\$17.18 million) include satellite data analysis, advanced fire modeling, fire potential index, research and academic partnerships, meteorology information technology support expense, weather stations expense, the satellite fire detection system, and numerical weather prediction.
 12. Customer Battery Programs (\$30 million) explores deploying multiple battery solutions to improve customer reliability and resiliency, enhance load management, and reduce system costs.
 13. Inspection, Preventative, and Corrective Maintenance (\$58.5 million) focuses on distribution substation O&M.
 14. Interconnections – Electric Grid Interconnection (\$2 to \$9.4 million) administers interconnecting electric generation projects to the distribution system.

15. Customer Electrification & Grid Modernization Technologies Programs (CEGMTP): Driving Stakeholder Readiness for Electrification (\$10 to \$12 million) aims to reduce barriers that increase cost, complexity, uncertainty, and inaction for customers considering electric vehicles and building electrification measures.
16. CEGMTP: Customer Intake and Management Platform (\$3 to \$3.25 million) aims to modernize and unify how customers access and participate in PG&E programs.
17. CEGMTP: Optimizing Asset Utilization to Accelerate Interconnection & Modernize the Electrical Grid (\$1 to \$20 million) aims to scale deployment of solution that optimize the use of existing grid assets and accelerate customer interconnection and energization.
18. Enterprise Safety Access Program (\$2 to \$2.5 million) aims to increase safety for coworkers and contractors assessing PG&E's assets and increase operational efficiency to access PG&E assets for inspections, operations, and maintenance.
19. Lone Safety Worker Program (\$2.92 million) supports PG&E's Working Alone Tactical Communications Hub Desk and provides devices and technologies for individuals or crews working in remote areas with limited communication options.
20. Performance Playbook (\$4 to \$5 million) aims to enable visual management, problem solving, standard work, and waste elimination to enable a better decision-making and operating system.
21. Workforce and Customer Safety and Education Enhancements (\$6 to \$12 million) encompasses security and educational initiatives designed to protect employees and provide customers and communities with safety and environmental issues.
22. PG&E Contingency Uses: (1) for Safety and Risk and (2): DCPD Operational Costs (\$0 to 50 million) aims to support Safety and Risk programs: MWCs: BH, DD (Electric Distribution Routine Emergency), AR, DD, EY, IU, and HY

(Field Metering), GA (E T&D Maintenance OH Poles), BA
(Electric Distribution Operating Activities), BF
(Inspections).¹²⁶

8.2. Party Positions

CUE supports PG&E's VPF spending plan.¹²⁷ CARE and WEM state that VPF funds should be used to lower DCP's revenue requirement.¹²⁸ A4NR states that VPF funds should be used for the feedwater heaters, CRVS condenser replacement, and intake bar rack replacement that PG&E has requested recovery for through the 2027 DCP O&M budget.¹²⁹ PG&E responds that A4NR has not offered "any compelling evidence demonstrating that redirecting funds to the identified projects would better satisfy the statutory requirements than PG&E's proposed portfolio."¹³⁰ PG&E also states that its VPF spending plan implements complies with the percentage-based framework adopted by D.24-12-033 and therefore should not be used to lower DCP's revenue requirement as proposed by CARE and WEM.¹³¹

8.3. Discussion

The Commission agrees with PG&E's argument that its 2027 VPF spending plan complies with the requirements of R.23-12-036 as well as Pub. Util. Code Section 712.8 (s)(1). Accordingly, this decision approves PG&E's 2027 VPF spending plan.

¹²⁶ Ex. PG&E-01 at 7-7 to 7-57.

¹²⁷ CUE Opening Brief at 6.

¹²⁸ Ex. CARE Opening Brief at 28-29, WEM Opening Brief at 10.

¹²⁹ Ex. A4NR-01 at 10, 22, and 25.

¹³⁰ PG&E Opening Brief at 35.

¹³¹ PG&E Opening Brief at 32.

9. 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.25-12-007 and how the application addressed these requirements.¹³²

No party argued that PG&E's application did not comply with D.23-12-036, D.24-12-033, and D.25-12-007.

10. 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 Docket Card for that proceeding on the Commission's website. Rule 1.18(a) requires that all written public comment submitted prior to the submission of the proceeding are part of the administrative record of the proceeding. 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 28 members of the public submitted comments opposing the requested rate increase.

11. 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.

12. 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

¹³² A.26-03-031 at 18-20.

Procedure. Comments were filed on _____, and reply comments were filed on _____ by _____.

13. 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 DCPD extended operations cost application.
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, 2027 to support DCPD 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 DCPD for the Record Period, and (3) a proposal to establish the DCNBC applicable to all Commission jurisdictional customers based on the forecasted net costs.
4. PG&E estimates \$1,350.789 million for DCPD costs, statutory fees, and substitution capacity expenses, with an offsetting \$728.247 million of CAISO net forecasted market revenue and \$296.923 million in DC Balancing Account amortization, as well as the addition of \$14.335 million franchise fees and uncollectibles, for a net revenue requirement of \$933.799 million.
5. PG&E's forecasted O&M expense of \$780.456 million includes the base O&M expense, projects expense, nuclear fuel expense, and employee retention program expense.

6. PG&E's testimony demonstrates that past PWROG activities may qualify for exemptions to AB 1167 and is sufficient to allow PG&E to recover in rates forecasted costs associated with PG&E's PWROG membership.

7. A previous GRC's determination regarding the CRVS condensers replacement has no bearing on this application.

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

9. 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.

10. DCPD 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 \$0 is correct.

12. 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.

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

14. 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.

Conclusions of Law

1. PG&E's 2027 DCPD extended operations net revenue requirement of \$933.799 million should be approved.

2. The approved costs should be reflected in statewide rates starting on January 1, 2027.

3. PG&E's request to recover \$780.456 million in total O&M costs for the period January 1 to December 31, 2027, is reasonable.

4. The \$26 million in DCPD costs that PG&E originally classified as transition and licensee renewal expenses should be recovered from the DCEOBA.

5. PG&E should detail the PWROG activities paid for with ratepayer funds as part of its true-up advice letter filing for the record period. If the Commission finds that any such ratepayer-funded activities constitute non-exempt political influence activities, all costs associated with such activities should be disallowed.

6. PG&E's request for \$284 million in VPFs, \$116.6 million in Fixed Management Fee, and \$0 to be recorded to the liquidated damages subaccount of the DCEOBA should be approved.

7. PG&E's liquidated damages funding request of \$0 complies with Pub. Util. Code Section 712.8(g), is reasonable, and should be approved.

8. PG&E's RA substitution capacity cost forecast of \$14.3 million for the extended operations period of January 1 through December 31, 2027 should be approved.

9. PG&E's nuclear fuel cost forecast and straightline amortization proposal are reasonable, comply with Pub. Util. Code Sections 712.8(c)(1)(C), and 712.8(h)(1) and Commission decisions and resolutions interpreting those statutory sections, and should be approved.

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

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

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

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

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

15. 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 net revenue requirement of \$933.799 million covering the extended operations costs of Diablo Canyon Power Plant from January 1 to December 31, 2027, 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, 2027.

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 2026.

3. Pacific Gas and Electric Company is ordered to detail in its true-up advice letter filing for the record period the Pressurized Water Reactor Owners Group activities paid for with ratepayer funds. If the Commission finds that any such

ratepayer-funded activities constitute non-exempt political influence activities, all costs associated with such activities will be disallowed.

4. Pacific Gas and Electric Company's proposed volumetric performance fees spending plan for the January 1 to December 31, 2027 period is approved.

5. Pacific Gas and Electric Company's testimony satisfies all the regulatory requirements set forth in Decisions 23-12-036, Decision 24-12-033, Decision 25-06-002, and Decision 25-12-007.

6. 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.

7. 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 11, 2026.

8. 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.

9. Application 26-03-031 is closed.

This order is effective today.

Dated _____, at Sacramento, California.