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 2026 Volumetric Performance Fees (U 39 E)	Application No. 25-03______

APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) 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 EXPENDITURES OF 2026 VOLUMETRIC PERFORMANCE FEES

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**BEFORE THE PUBLIC UTILITIES COMMISSION
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I. INTRODUCTION

Pursuant to Rules 2.1 and 3.2, Public Utilities Code[1] § 712.8(h)(1), and California Public Utilities Commission ("Commission") Decisions ("D.") 23-12-036 and D.24-12-033, Pacific Gas and Electric Company ("PG&E") respectfully submits this application for review and approval of forecast costs covering the period starting January 1 through December 31, 2026 (the "Record Period") for Diablo Canyon Power Plant ("DCPP" or "Diablo Canyon") extended operations for inclusion in statewide rates starting on January 1, 2026.

PG&E's 2026 forecast costs are shown in the table below and include $1,339 million for DCPP operating costs, statutory fees, and substitution capacity expenses, which is offset by a net forecast of $935 million for California Independent System Operator ("CAISO") market revenues received in the CAISO energy market. After incorporating certain fees, the resulting total net revenue requirement for ratesetting is $410 million for the 2026 calendar year.

[1] Unless indicated otherwise, all statutory sections in this application are to the Public Utilities Code.

TOTAL REVENUE REQUIREMENT FOR RATESETTING

Line No.		Chapter Cross Reference	Diablo Canyon Extended Operations[a] 2026 Cost ($1000s)		
			Statewide (A)	PG&E Specific (B)	Total (C)
1	**Total Cost Forecast**				
2	Operation and Maintenance Cost Forecast	Chapters 2 & 4	726,245		726,245
3	Management , Performance Fees, & Liquidated Damages	Chapters 4 & 5	320,573	131,689	452,262
4	Resource Adequacy Substitution Capacity	Chapter 3	160,837		160,837
5	**Subtotal Operational Revenue Requirement**		**1,207,655**	**131,689**	**1,339,344**
6	**DCPP Market Revenues**				
7	CAISO Market Revenues	Chapter 6	(934,925)		(934,925)
8	**Total Net Forecast Cost (excluding RF&U)**		**272,730**	**131,689**	**404,419**
9	RF&U (PG&E) + FF&U (SCE) and FF&U (SDG&E)[b]	Chapter 10	3,924	1,649	5,572
10	**DCEO Revenue Requirement for Ratesetting**		**276,654**	**133,338**	**409,992**

Notes:
(a) Amounts in 2026 dollars ($s)
(b) SDG&E FF&U revenue for its DCNBC will be collected in Distribution Charge

The total Diablo Canyon revenue requirement for the Record Period is allocated to the three large investor-owned utilities ("IOU") as follows: (1) $257 million to PG&E; (2) $125 million to Southern California Edison Company ("SCE"); and (3) $28 million to San Diego Gas & Electric Company ("SDG&E"). Each of the IOUs independently calculate and present its respective Diablo Canyon Non-Bypassable Charge ("DCNBC") in Chapter 10 based on its allocation of the total net revenue requirement presented in the table above.

As a result, PG&E's system average bundled service rate would decrease by approximately 0.4 percent to 35.4 cents per kWh when compared to the present system average bundled service rate of 35.6 cents per kWh, effective March 1, 2025. PG&E's allocated revenue requirement for the calendar year 2026 results in a decrease of $0.98 per month bill impact for the average non-CARE residential customer. SCE's allocated revenue requirement for calendar year 2026 is estimated to result in a decrease of $1.38 per month bill impact for the average non-CARE residential customer. SDG&E's allocated revenue requirement is estimated to result in a decrease of $0.77 per month bill impact for average non-CARE residential customers.

This application supports PG&E's efforts to respond to the State's call to support electric reliability for all Californians and continuing operations at Diablo Canyon. As presented in Chapter 1, DCPP has additional value to the state and to customers that is not reflected in the total cost presentation. For example, on average, for the 2025 to 2030 extended operations cost recovery period, when accounting for the estimated imputed Resource Adequacy ("RA") attribute value, which would otherwise be realized through RA sales, the benefits on average per year are ~$540 million to statewide customers. Further, as provided in Chapter 1, DCPP's extended operations through 2030 are expected to reduce greenhouse gas ("GHG") emissions from natural gas generation and imported energy by 34.50 million metric tons in total. An average single refueling outage year of extended operations is expected to reduce GHG emissions by 6.98 million metric tons, or the equivalent of carbon dioxide emissions from 1.6 million cars per year.[2]

DCPP is delivering on its commitment to serve California hometowns with safe, reliable, affordable, and clean energy. Annually, Diablo Canyon produces approximately ~18,000 gigawatt hours of safe and reliable GHG free energy. Key accomplishments in the last year include: (1) achieving the highest performance category in the U.S. Nuclear Regulatory Commission's rankings, (2) recognition for DCPP's excellent performance and safe operations by industry peers and nuclear oversight groups, and (3) achieving a 99.5 percent capacity factor for Unit 1 in 2024.

As directed in D.23-12-036, this application includes: (1) a forecast of the 2026 costs of extended operations, (2) a forecast of market revenues for Diablo Canyon, and (3) a proposal to establish the DCNBC applicable to all Commission-jurisdictional customers based on forecast net costs and applicable amounts. This application also includes information responsive to the Commission's directives in D.24-12-033 that PG&E: (1) provide detailed information for all

[2] See U.S. Environmental Protection Agency Greenhouse Gas Equivalencies Calculator: https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator#results.

projects with costs more than $1 million,[3] (2) provide the total cost of DCPP extended operations through 2030 for informational purposes, (3) provide updated administrative and general ("A&G") costs for 2025 and beyond, and (4) provide 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.[4] PG&E also discusses Diablo Canyon Extended Operations Balancing Account ("DCEOBA") recorded activity through January 31, 2025. PG&E only requests cost recovery for the Record Period, that is January 1 to December 31, 2026, in this application.

In regard to RA substitution costs, which are based on the Power Charge Indifference Adjustment ("PCIA") market price benchmarks and are a component of the revenue requirement, PG&E notes that the Commission issued an *Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes,* Rulemaking 25-02-005, in February 2025. This rulemaking may affect the calculation methodology of the RA benchmark price, issued on October 1, 2025, which is incorporated into the final revenue requirement.

This application also presents for Commission review and approval a plan for prioritizing the use of the 2026 volumetric performance fees ("VPF") consistent with § 712.8(f)(5), § 712.8(s) and D.23-12-036.[5] The VPF revenues are collected in lieu of a rate-based return[6] and provide a unique opportunity to accelerate and increase spending on important public purpose priorities identified in § 712.8(s)(1). The 2026 prioritization plan presents a balanced and pragmatic suite of programs that endeavors to accommodate the concerns and interests of a range

[3] D.24-12-033, p. 81, Conclusion of Law 5.
[4] D.24-12-033, pp. 69-70.
[5] PG&E submitted an appeal in California state court of D.23-12-036 and D. 24-05-068 (denying PG&E's application for rehearing of D.23-12-036) concerning the Commission's findings, legal conclusions, and orders relating to PG&E's use of VPFs provided to PG&E under § 712.8(f)(5) and the Commission's interpretation of Public Utilities Code Section 712.8(s)(1). The appeal is being litigated separately from this proceeding.
[6] Pub. Util. Code, § 712.8(f)(5).

of stakeholders while advancing priority work. PG&E also presents its accounting and control processes, consistent with the description in PG&E's February 18, 2025, Advice Letter ("AL") 7511-E.[7]

The schedule set forth in Section VI.E below assumes the Commission will resolve this application by the first business meeting in December to allow the IOUs to implement rate changes as of January 1, 2026. Timely approval is necessary to ensure that statewide rates accurately recover forecast extended operations costs from Commission- jurisdictional load serving entity ("LSE") ratepayers. When approval of this forecast application is delayed, the forecast revenues are misaligned to the recorded costs. As recorded extended operations costs begin to show up in the DCEOBA, they are matched to market revenues and statewide customer rates in the form of PG&E billed revenues and SCE and SDG&E remitted revenues. The 12-month forecast of billed/remitted revenues must align to PG&E's 12-month forecast of record costs. Thus, timely approval is essential to avoid a systematic mismatch in timing between the forecast period and the time at which the recorded costs, market revenues, and billed/remitted revenues are recovered in rates. PG&E requests this Commission's final decision set rates effective as of January 1, 2026.

II. LEGAL AND REGULATORY BACKGROUND

A. Senate Bill 846 and Decision 22-12-005

On September 2, 2022, Governor Newsom signed Senate Bill ("SB") 846 authorizing the potential extension of DCPP operations, California's only remaining nuclear power plant in operation, for up to five years beyond its current operating licenses.[8] This directive was effective immediately as SB 846 was passed as urgency statute. In authorizing the potential extension of Diablo Canyon operations, SB 846 states:

> Preserving the option of continued operations of the Diablo Canyon powerplant for an additional five years beyond 2025 may

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[7] PG&E AL 7511-E, available at: <https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7511-E.pdf> (accessed Mar. 27, 20225).
[8] Pub. Res. Code, § 25548(b).

> be necessary to improve statewide energy system reliability and to reduce the emissions of greenhouse gases while additional renewable energy and zero-carbon resources come online, until those new renewable energy and zero-carbon resources are adequate to meet demand. Accordingly, it is the policy of the Legislature that seeking to extend the Diablo Canyon powerplant's operations for a renewed license term is prudent, cost effective, and in the best interests of all California electricity customers. The Legislature anticipates that this stopgap measure will not be needed for more than five years beyond the current expiration dates.[9]

Additionally, SB 846 tasked the Commission to direct and authorize PG&E to "take all actions … necessary to operate the powerplant beyond the current expiration dates, so as to preserve the option of extended operations…."[10] Subject to continued authorization to operate from the U.S. Nuclear Regulatory Commission ("NRC") and certain findings and conclusions from the Commission, the statute establishes new retirement dates of October 31, 2029 for Unit 1 and October 31, 2030 for Unit 2. In the months following the passage of SB 846, PG&E, acting at the direction and for the benefit of the state of California, took immediate and extensive action to effectuate the state's directives. Multiple state and federal agencies did the same to support continued operations at DCPP.

Two forms of government funding streams are identified in SB 846 to support extended operations at DCPP: a $1.4 billion loan through the California Department of Water Resources ("DWR") and funds awarded through the U.S. Department of Energy ("DOE") Civil Nuclear Credit ("CNC") Program. The funds provided by the DOE will be used to repay the DWR loan. The government funding streams are intended to recover transition costs and costs supporting extended operations, but not the cost of extended operations. Costs that are covered by government funding streams are not included in PG&E's forecast or resulting rate request. The final Civil Nuclear Credit Award and Payment Agreement ("CAPA") between PG&E and the DOE was executed in the first quarter of 2024.

In implementing SB 846, the Commission adopted a broadly prescriptive cost recovery

[9] Pub. Res. Code, § 25548(b).
[10] Pub. Util. Code, § 712.8(c)(1)(A).

and approval process intended to fully recover the costs of Diablo Canyon operations and assign those costs to customers of all Commission-jurisdictional LSEs. This new regulatory process establishes the DCNBC and provides that forecasted costs are trued up to actual recorded costs through an expedited Tier 3 advice letter process.[11] Section 712.8(h)(1) directs the Commission to authorize the recovery of all reasonable costs and expenses necessary to operate DCPP, and also that there will be no further review of costs provided that actual costs are below 115 percent of forecast costs. This section does not allow PG&E to earn a rate of return on any of these costs, directing that "costs shall be recovered as an operating expense and shall not be eligible for inclusion in the operator's rate base."[12]

SB 846 established several costs and fees to be included in the extended operations forecast, including two distinct streams of performance and management fees to PG&E in lieu of the traditional rate-base return on capital investments. Specifically, PG&E receives a fixed management fee of $50 million per unit per year, as well as the VPFs consisting of $13.00 per megawatt-hour ("MWh"), in 2022 dollars, for the period of extended operations. The volumetric performance fee is split into two categories, with the first $6.50/MWh, in 2022 dollars, to be collected from all Commission-jurisdictional customers and an additional $6.50/MWh, in 2022 dollars, to be collected from customers in PG&E's service territory only. Section 712.8(s)(1) directs that the VPF revenues be spent, to the extent not needed for DCPP, to accelerate, or increase spending on, six public purpose priorities critical to advancing California's clean energy and decarbonization goals.[13] In addition, SB 846 provides for the funding of a liquidated damages account until the balance reaches $300 million to be used to offset the costs of any unplanned outages.[14] The Liquidated Damages Subaccount is a subaccount of the DCEOBA.[15]

[11] Pub. Util. Code, § 712.8(h)(1).
[12] Pub. Util. Code, § 712.8(h)(1).
[13] Pub. Util. Code, § 712.8(s)(1)(A) – (F).
[14] Pub. Util. Code, §§ 712.8(g) and (i).
[15] Commission Resolution E-5299, approving ALs 6870-E and 6870-E-A, available at: <https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_6870-E-A.pdf> (accessed Mar. 27, 2025). See also pending AL 7204-E-A.

In D.22-12-005, the Commission directed PG&E to take "all … actions that would be necessary" to preserve extended operations and to track costs associated with continued and extended operations.[16] The Commission also directed PG&E to establish the Diablo Canyon Transition and Relicensing Memorandum Account ("DCTRMA") and the DCEOBA. The DCTRMA tracks costs and revenues associated with government funding streams for transitioning the plant to extended operations. The DCEOBA tracks the costs that will be recovered from all customers of all Commission-jurisdictional LSEs.

B. Decision 23-12-036

In D.23-12-036, the Commission authorizes new retirement dates for Diablo Canyon Units 1 and 2, subject to certain conditions.[17] The decision also adopts an application process, of which this is the second instance, to authorize forecast DCPP extended operations costs.[18] It also authorized a subsequent true-up process to actual costs and market revenues for the prior calendar year via an expedited Tier 3 advice letter.[19] As with all two-way balancing accounts, PG&E's annual filings may reflect either an over or undercollection depending on actual cost and revenues.

In addition, D.23-12-036 directs the allocation of RA "benefits of DCPP extended operations to each large electrical corporation service area on the basis of a 12-month coincident peak demand,"[20] and that PG&E "determine the allocation of costs and benefits of DCPP extended operations" among PG&E, SCE, and SDG&E.[21] To implement this, the Commission directed that the Energy Division should "utilize the CAM process to determine the allocation of RA benefits to SCE and SDG&E and among the 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

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[16] D.22-12-005, p. 33, Ordering Paragraph (OP) 2.
[17] D.23-12-036, p. 135, OP 1.
[18] *Id.*, p. 136, OP 4.
[19] *Id.*, p. 136, OP 4.
[20] *Id.*, p. 130, COL 35.
[21] *Id.*, p. 133, COL 55.

compliance filing deadline."[22] Thus, Energy Division will allocate the RA benefits later this year to LSEs in each of the IOUs' service territories under the CAM process established in D.06-07-029.

In regard to GHG-free energy allocation, PG&E developed a process with stakeholders and completed its first annual process for GHG-free energy allocation, which is described in PG&E Advice Letter 7295-E/E-A.[23] The transactions reflecting the allocations will be submitted on an informational basis in PG&E's Q4 Quarterly Compliance Report and will be submitted for Commission review in PG&E's Tier 3 Advice Letter submitted in March 2026.

Finally, the Commission directed PG&E to present its planned use of the $13/MWh VPFs in an application.[24] PG&E must demonstrate that its plan is consistent with the critical public purpose priorities in § 712.8(s)(1) prior to expenditure of VPF funds.[25] In this application, PG&E addresses the forecast amount of ratepayer funds to be collected during the Record Period and how PG&E plans to spend those funds. Some of the requirements associated with expenditure of the VPFs are met on a retrospective basis, e.g., reporting requirements including a declaration from PG&E's Chief Financial Officer and will be presented for the first year of expenditures in March 2026.[26]

C. Decision 24-12-033

D.24-12-033, among other items, approved PG&E's first annual extended operations revenue requirement for its first record period, as well as the allocation to the other IOUs.[27] For this and future forecast and cost recovery proceedings, the decision directed that PG&E:

> (1) Provide detailed project summaries for all projects over $1 million, instead of all projects over $3 million as PG&E did in its Application ("A.") 23-03-018 proceeding as modeled after the General Rate Case ("GRC").

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[22] *Id.*, p. 133, COL 55.
[23] PG&E AL 7295-E-A, available at: <https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7295-E-A.pdf> (accessed Mar. 27, 2025).
[24] D.23-12-036, p. 139, OP 15.
[25] *Id.*, p. 139, OP 15.
[26] *Id.*, pp. 111-116.
[27] *Id.*, pp. 84-85, OP 1 and 2.

(2) Provide the total cost of DCPP extended operations through 2030 in each annual application for informational purposes.

(3) Provide updated A&G costs for 2025 and beyond.

(4) Provide 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.

PG&E has included this information in this application as required.

D. Proposed Decision in Phase 2 of Rulemaking 23-01-007

On February 28, 2025, the Commission issued a proposed decision in Phase 2 of Rulemaking ("R.") 23-01-007, which addresses some requirements intended for this application.[28] The earliest Commission voting meeting it would be approved on is April 3, 2025, which is after the submission of this application on March 28, 2025. PG&E has provided the Commission with comments recommending modifications to the proposed decision. PG&E seeks the opportunity to provide supplemental testimony if needed to comply with the final decision in Phase 2 of R.23-01-007.

III. DESCRIPTION OF PG&E'S REQUESTED RELIEF IN THIS APPLICATION

A. Forecast Revenue Requirement for Record Period

The revenue requirement for the Record Period represents the forecast of costs of extended operations from January 1 to December 31, 2026, including operations and maintenance ("O&M") expense and project costs, fuel expense, tax expense, procurement costs associated with capacity and energy substitution for DCPP's planned and maintenance outages, and statutory costs associated with SB 846, netted with forecast market revenues. Unit 1 began extended operations on November 3, 2024, and Unit 2 begins extended operations on August 27, 2025. PG&E does not propose to recover common costs that were included in PG&E's 2023 GRC (which was submitted before the passage of SB 846), such as A&G costs in the rate established by this application. However, pursuant to D.24-12-033,[29] PG&E presents illustrative

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[28] *Proposed Decision on Phase 2 Issues* issued in R.23-01-007 (Feb. 28, 2025).
[29] D.24-12-033, p. 83, COL 24.

A&G costs for 2025 and 2026, even though no A&G is being recovered for 2026 in this application. In addition, consistent with §§ 712.8(f)(5) and 712.8(f)(6)(A), PG&E requests approval of an escalation rate and methodology for the fixed fee and VPF.

The table below expands on the table presented in Section I, *Total Revenue Requirement for Ratesetting*, to show cost component details of the Record Period revenue requirement. As shown below, line 2 includes costs to operate DCPP during this Record Period, including direct costs for O&M, support costs including taxes, benefits and standard PG&E overheads, employee retention, and regulatory compliance items discussed in Chapters 2 and 4. Line 3 includes a forecast for resource adequacy substitution capacity expenses, which is discussed in Chapter 3. Lines 8-11 provide additional detail regarding statutory charges and fees included in the cost forecast, including the performance and management fees, authorized in SB 846. Costs on line 13 plus the 2025 balancing account forecast on Line 17 total $1.339 million. These costs are then netted against generation market revenues (line 15), resulting in approximately $404.4 million, (line 18), excluding Franchise Fees and Uncollectable (FF&U) revenues. The IOUs' FF&U revenues (line 20) are then added onto line 18, resulting in a net revenue requirement to be recovered in rates of approximately $410.0 million.

DETAILED TOTAL NET REVENUE REQUIREMENT FOR 2026 RATESETTING
(THOUSANDS OF DOLLARS)

Line No.		Chapter Cross Reference	Diablo Canyon Extended Operations[a] 2026 Cost ($1000s)		
			Statewide (A)	PG&E Specific (B)	Total (C)
1	Operational Revenue Requirement				
2	Operation and Maintenance Cost Forecast	Chapters 2 & 4	726,245		726,245
3	Resource Adequacy Substitution Capacity	Chapter 3	160,837		160,837
4					
5	**Subtotal Operational Revenue Requirement**		**887,082**		**887,082**
6					
7	Management, Performance Fees, and Liquidated Damages				
8	Management Fee	Chapters 4 & 5	113,884		113,884
9	Liquidated Damages	Chapters 4 & 5	75,000		75,000
10	Volumetric Performance Fee	Chapters 4 & 5	131,689		131,689
11	***PG&E Specific*** Volumetric Performance Fee	Chapters 4 & 5		131,689	131,689
12	**Subtotal Statutory Fees**		**320,573**	**131,689**	**452,262**
13	**Total Cost Forecast (Line 5 + Line 12)**		**1,207,655**	**131,689**	**1,339,344**
14	Offsetting Market Revenues				
15	CAISO Market Revenues	Chapter 6	(934,925)		(934,925)
16	Balancing Account Amortization				
17	DCEOBA	Chapter 8	0		0
18	Subtotal Net Cost (Line 13 + Line 15 + Line 17)		272,730	131,689	404,419
19					
20	RF&U (PG&E) + FF&U (SCE) and FF&U (SDG&E)[b]	Chapter 10	3,924	1649	5,572
21	**DCEO Revenue Requirement for Ratesetting**		**276,654**	**133,338**	**409,992**

Notes:
(a) Amounts in 2026 dollars ($s)
(b) SDG&E FF&U revenue for its DCNBC will be collected in Distribution Charge

As discussed below in Section V, at the time of PG&E's Fall Update, PG&E will present updated amounts for the revenue requirement, including year-end balances from any over- or under-collection for 2025 amounts.

B. Diablo Canyon Allocation to the IOUs and DCNBC

As authorized by SB 846 and D.23-12-036, the DCNBC is a statewide charge that will apply to all Commission-jurisdictional customers of electrical corporations, electric service providers, and Community Choice Aggregators, which will be billed through the CPUC-jurisdictional IOUs.[30] To produce the DCNBC, the revenue requirement for the Record Period is allocated among the three large IOUs based on the 12-month coincident peak demand using publicly available data.[31] Once the revenue requirement is allocated to each IOU, the DCNBC rate calculation by rate class utilizes a process that mirrors the CAM process. For each IOU, the DCNBC by rate class is presented in Chapter 10. The DCNBC rates will be included in their public purpose program ("PPP") rates.[32]

PG&E, SCE, and SDG&E present for Commission review the revenue requirements allocated to each IOU that support rate proposals for the DCNBC, a summary of those allocations is shown below:

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[30] D.23-12-036, pp. 138-139, OP 14.
[31] *Id.*, pp. 136-137, OP 7.
[32] *Id.*, pp. 138-139, OP 14.

2026 DIABLO CANYON EXTENDED OPERATIONS COST ALLOCATION

(THOUSANDS OF DOLLARS)

Line No.		Chapter Cross Reference	2026 Cost Allocation ($1000s) 44.9% Pacific Gas & Electric	45.3% Southern California Edison	9.8% San Diego Gas & Electric	2026 Total
1	Operational Revenue Requirement		(D)	(E)	(F)	(G)
2	Operation and Maintenance Cost Forecast	Chapters 2 & 4	326,084	328,989	71,172	726,245
3	Resource Adequacy Substitution Capacity	Chapter 3	72,216	72,859	15,762	160,837
4	**Subtotal Operational Revenue Requirement**		**398,300**	**401,848**	**86,934**	**887,082**
5	Management, Performance Fees, and Liquidated Damages					
6	Management Fee	Chapters 4 & 5	51,134	51,589	11,161	113,884
7	Liquidated Damages	Chapters 4 & 5	33,675	33,975	7,350	75,000
8	Volumetric Performance Fee	Chapters 4 & 5	59,128	59,655	12,906	131,689
9	***PG&E Specific* Volumetric Performance Fee**	Chapters 4 & 5	131,689			131,689
10	**Subtotal Statutory Fees**		**275,626**	**145,219**	**31,416**	**452,262**
11	**Total Cost Forecast (Line 4 + Line 10)**		**673,926**	**547,068**	**118,350**	**1,339,344**
12	Offsetting Market Revenues					
13	CAISO Market Revenues	Chapter 6	(419,781)	(423,521)	(91,623)	(934,925)
14	Balancing Account Amortization					
15	DCEOBA	Chapter 8	0	0	0	0
16	Subtotal Net Cost (Line 13 + Line 15 + Line 17)		254,145	123,547	26,728	404,419
17	Uncollectibles, Franchise Fees, and SF Revenue Fee Factor[c]	Chapter 10	1.2520%	1.1061%	3.8314%	
18	RF&U (Col. A = Col. D + Col. E + Col. F - Col. B) (Col. B = Col. A, Line 3 x Col. D, Line 23)	Chapter 10	3,182	1,367	1,024	5,572.486
19	**DCEO Revenue Requirement for Ratesetting (Line 16 + Line 18) for PG&E and SCE (Line 16) for SDG&E**		**257,327**	**124,913**	**26,728**	**408,968**
20	**Distribution Revenue (SDG&E FF&U)**				**1,024**	**1,024**
21	**Volumetric Performance Fee (VPF) as a Percent of Net Costs[d]**		**75.08%**	**48.29%**	**48.29%**	

Notes:
(a) Amounts in 2026 dollars ($s)
(b) D.23-12-036, OP8 and OP11
(c) SDG&E's revenues for its DCNBC will be collected in the Distribution Charge.
(d) VPF Revenue allocation for Revenue Reporting

C. Request for Revision to the DOELBA Preliminary Statement

PG&E requests authority to modify the Preliminary Statement Part DZ, Department of Energy Litigation Balancing Account ("DOELBA") to create a subaccount for spent nuclear fuel claims proceeds attributable to the DCEOBA. PG&E proposes to retain the same approved methodology used today for the existing subaccounts that are transferred to Portfolio Allocation Balancing Account ("PABA") and Nuclear Decommissioning Adjustment Mechanism ("NDAM"), which follow the method initially approved by the Commission in PG&E's 2014 GRC Decision[33] and reaffirmed in subsequent proceedings. PG&E requests that this implementation occur through a Tier 1 advice letter within 60 days following the issuance of a decision in this case. PG&E's Chapter 2 request in the proceeding also proposes an updated allocation of spent fuel storage claims proceeds received from the DOE for the 2026 record period across the PABA, NDAM, and DCEOBA.

D. Prioritization Plan for Expenditures of 2026 Volumetric Performance Fees

PG&E presents its plan for prioritizing the use of the VPF compensation[34] earned in 2026 in this application for Commission approval in compliance with § 712.8(s) and D.23-12-036. The VPF revenues are collected in lieu of a rate-based return[35] and provide a unique opportunity to accelerate and increase spending on important public purpose priorities identified in § 712.8(s)(1). PG&E's plan includes a range of activities that accelerate and promote the public purpose priorities enumerated in § 712.8(s)(1). The 2026 plan presents a balanced and pragmatic suite of programs that endeavors to accommodate the concerns and interest of a range of stakeholders while advancing priority work. PG&E also presents its accounting and control processes, consistent with the description in PG&E's AL 7511-E.[36]

In addition, PG&E seeks the opportunity to supplement its application or testimony depending on the outcome of the final decision in Phase 2 of R.23-01-007.

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[33] D.14-08-032, pp. 435-437.
[34] Pub. Util. Code, § 712.8(s)(1).
[35] Pub. Util. Code, § 712.8(f)(5).
[36] PG&E AL 7511-E, available at: <https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7511-E.pdf> (accessed Mar. 3, 20225).

E. Finding of Compliance with D.23-12-036 and D.24-12-033

PG&E provides the table below (also shown in Chapter 1) showing where in the testimony it has demonstrated compliance with D.23-12-036 and D.24-12-033 requirements.

Line No.	Action Required	Decision Reference	Compliance Action
Decision 23-12-036			
1	PG&E's proposed Energy Resource Recovery Account ("ERRA")-like process to authorize forecast DCPP extended operations costs, with a subsequent true-up to actual costs and market revenues for the prior calendar year via an expedited Tier 3 advice letter process, is approved as modified by this decision. PG&E shall file the first of these DCPP Extended Operations Cost Forecast applications no later than March 29, 2024, and shall file subsequent annual DCPP Extended Operations Cost Forecast applications no later than March 31 beginning in 2025 and ending the year before extended operations are complete.	OP 4	See PG&E Application, filed on March 28, 2025
2	As part of its annual DCPP Extended Operations Cost Forecast Applications, PG&E should: a) Provide detailed projections of all costs and revenues associated with DCPP extended operations, in a manner similar to PG&E's presentation in its GRC and ERRA Forecast proceedings; b) Quantify the impact of DCPP's extended operations on its common costs relative to the amount approved in its 2023 GRC; and c) Demonstrate it will not double count the common costs it proposes for recovery in its GRC and DCPP Extended Operations Cost Forecast applications.	COL 54	Item 2.a Expense O&M and Projects Costs – See Chapter 2 Revenues – See Chapter 4 Item 2.b — See Chapter 1 Section N Item 2.c — See Chapter 1 Section N
3	PG&E, SCE, and SDG&E are directed to provide joint testimony proposing an allocation among themselves of the statutorily-defined DCPP extended operations costs applicable to all LSE, and the revenue associated with the $6.50 per MWh volumetric fee under Pub. Util. Code Section 712.8(f)(5). PG&E, SCE, and SDG&E may use public load data to determine each electrical corporation's share of the 12-month coincident peak demand.	OP 7	See Chapter 10
4	The Diablo Canyon Extended Operations Cost Forecast proceeding should: a) Determine the allocation of costs and benefits of DCPP extended operations among the large electrical corporations' service areas; and	COL 55	See Chapter 10

Line No.	Action Required	Decision Reference	Compliance Action
Decision 23-12-036			
	b) 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 RA benefits to SCE and SDG&E and among the 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.		
5	PG&E is directed to file an annual application, as described in this decision, no later than March 1, 2026, until the retirement of Diablo Canyon Nuclear Power Plant Unit 1 and Unit 2, to report the amount of compensation earned under California Pub. Util. Code § 712.8(f)(5), how it was spent, and a plan for prioritizing the uses of such compensation the next year. PG&E is not prohibited from filing an application earlier than March 1, 2026, to request an earlier approval of its plan for prioritizing the uses of funds collected under California Pub. Util. Code § 712.8(f)(5). PG&E's application may also include one or more proposals that would allow PG&E to spend the performance-based fees while ensuring sufficient funding for the true-up process, as discussed elsewhere in this decision.	OP 15	See Chapter 7
Decision 24-12-033			
6	PG&E must provide the following information in the next Diablo Canyon Power Plant cost forecast proceeding: a) Detailed project summaries for all projects over $1 million, instead of all projects over $3 million; b) Total cost of Diablo Canyon Power Plant extended operations through 2030; c) Updated A&G costs for 2025 and beyond.	OP 10	a) See Workpapers Supporting Chapter 2 b) See Chapter 1 Table 1-1 c) See Chapter 1, Section N

Line No.	Action Required	Decision Reference	Compliance Action
Decision 23-12-036			
7	In D.22-12-005, the Commission concluded that "PG&E should attempt to recover the following transition and extended operations costs using government funding to the greatest extent possible: all costs associated with preserving the option of extended operations at DCPP; all plant and equipment improvement and investment costs; spent fuel storage capacity costs; and any related taxes or other revenue requirements." The Commission also stated that "In the event PG&E…records any of these costs directly to the DCEOBA without seeking government funding, PG&E should be prepared to explain why it 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.	pp. 18 and 19	See Chapter 2

F. Summary of Requested Relief

PG&E requests that the Commission approve the following:

1. DCPP revenue requirement from the Record Period of $410 million to be effective in rates on January 1, 2026, including the following forecasts and their underlying financial assumptions and calculations, subject to updates in the Fall Update:

    a. Operations and maintenance costs (including expenses, project costs, and statutory costs and fees, as well as associated escalation),

    b. Charges for the liquidated damages account pursuant to § 712.8(g),

    c. Resource Adequacy substitution capacity costs, including any updates from the results of R.25-02-005, or unless otherwise directed by the Commission,

    d. Operating expenses that would be amortized through 2030 (i.e., nuclear fuel procurement), and

    e. Netting of CAISO revenues for the period from January 1, 2026, to December 31, 2026.

2. The statewide Diablo Canyon Non-Bypassable Charge.

3. Modification of the DOELBA preliminary statement to create a sub-account for spent nuclear claim proceeds attributable to the DCEOBA, to be implemented in a Tier 1 advice letter within 60 days following the issuance of the decision.

4. PG&E's 2026 VPF plan and proposed spending priorities for the expenditures.

5. Find that PG&E's testimony satisfies all the regulatory requirements from D.23-12-036 and D.24-12-033.

IV. OVERVIEW OF PREPARED TESTIMONY

In support of this application, PG&E contemporaneously serves direct testimony and workpapers to support its revenue requirement and ratemaking request.

Chapter 1 (Introduction and Policy) provides the introduction and underlying policy of the proceeding, including the Legislature and the Governor's charge to the Commission in SB 846 to establish new retirement dates, which became the basis for D.23-12-036. This chapter summarizes PG&E's ratemaking requests for the Record Period, addresses the costs and benefits of DCPP extended operations through 2030, including benefits from RA and GHG-free energy and demonstration that common costs will not be double counted.

Chapter 2 (Forecast Operations and Maintenance Costs to be Recovered in 2026 Rates) contains PG&E's 2026 Record Period forecast of O&M costs. In this chapter, PG&E presents costs by Major Work Category, consistent with PG&E's historical GRC Testimony for Nuclear Operating Costs, which will describe categories of forecast costs.

Chapter 2 also includes proposed expense projects, similar to what would have been capital project forecasts historically addressed in PG&E's GRC. Execution of these projects is necessary to ensure safety and equipment reliability are maintained during extended operations of DCPP to meet the needs of all Californians. Consistent with § 712.8(h)(2), for any significant one-time expense project expenditures during the extended operations period, PG&E may propose an amortization period for such expenditures over a period of greater than one year for the purpose of reducing rate volatility, at an amortization rate determined by the Commission.

Chapter 2 also presents PG&E's proposal for straight line amortization for cost recovery of nuclear fuel over the period of 2025 through 2030. PG&E proposes the Commission approve the same methodology that was adopted in D.24-12-033 for the 2025 extended operations forecast proceeding.

In Chapter 3 (Generation Forecast and Resource Adequacy Substitution Capacity Cost

Forecast), PG&E provides testimony regarding the amount of forecast generation from extended operations for the Record Period, addresses requirements under the Commission's RA Program, PG&E's procurement of replacement capacity during DCPP planned and unscheduled outages, and substitution capacity procurement costs that are necessary to meet the state's reliability needs. Prior to SB 846, these issues were addressed in other proceedings. This chapter also discusses the Commission's directive that PG&E retain responsibility for obtaining substitute capacity during DCPP outages as D.23-12-036 determined it is reasonable for all LSEs that are allocated RA benefits to share in reasonable administrative and procurement costs associated with meeting DCPP substitution capacity obligations, including associated penalties and costs borne by non-DCPP resources.

Chapter 4 (Operational Revenue Requirement) contains cost inputs discussed in Chapter 2 that are incremental to the authorized 2023 GRC revenues, as well as costs from Chapter 3, and Chapter 5 in order to calculate the forecast revenue requirement request for DCPP Units 1 and 2 for the 2026 Record Period, and that are not eligible for government funding pursuant to SB 846, Assembly Bill 180, or the DOE CNC Program. Chapter 4 also explains PG&E's assumptions used in the revenue requirement model. Pub. Util. Code § 712.8(h)(1) requires that all extended operations costs shall be recovered as an operating expense and shall not be eligible for inclusion in PG&E's rate base. Pursuant to § 712.8(h)(1), PG&E's cost recovery for extended operations will be net of market revenues for those operations and any production tax credits of the operator.

Chapter 5 (Statutory Fees) discusses statutory fees, including the statewide VPFs pursuant to Section 712.8(f)(5), PG&E's service territory VPFs pursuant to § 712.8(f)(5), the fixed management fee for PG&E's operation of DCPP in lieu of a rate base return pursuant to § 712.8(f)(6)(A), escalation rate proposals, and liquidated damages subaccount funding pursuant to § 712.8(g).

Chapter 6 (California Independent System Operator Corporation Market Revenues) presents a forecast of the CAISO market revenues for the period of January 1, 2026, to

December 31, 2026, in a manner similar to its ERRA Forecast proceeding, which is based on a weighted average of on- and off-peak forward prices for the Test Year ("TY"). PG&E anticipates that in its Fall Update, its generation revenue forecast will be based upon the Energy Index on- and off-peak prices provided by the Commission's Energy Division on October 1 of each year pursuant to D.22-01-023.

In Chapter 7 (Planned Usage of Funds from Volumetric Performance Fees), PG&E presents its planned usage and programs for spending the 2026 VPFs pursuant to statutorily mandated public purpose priorities. In addition, PG&E also presents its cost tracking, controls, and compliance mechanism to ensure compliance with SB 846 and D.23-12-036. This includes how PG&E will track the VPF project expenditures to ensure they are incremental, and actions PG&E will take to ensure compliance with the prohibitions in § 712.8(s)(1) and (s)(2).

Chapter 8 (Diablo Canyon Extended Operations Balancing Account) addresses the subaccount contents of the DCEOBA, explains how it operates and the revision and true-up process. This discussion is consistent with Advice Letter 7509-E, which has an effective date of February 18, 2025,[37] and modifications submitted and still pending further disposition, including: Advice 7204-E filed on March 14, 2024[38] in compliance with D.23-12-036 directives, as further amended by Advice 7204-E-A filed on February 12, 2025;[39] and Advice 7531-E filed on March 10, 2025 in compliance with D.25-01-043.[40]

Chapter 9 (Net Revenue Requirement for Ratesetting) presents the net revenue requirement to be recovered in rates for consideration in this proceeding, which nets the forecast market revenues with total DCPP Results of Operations costs presented in Chapter 4 over the Record Period.

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[37] PG&E AL 7509-E, available at: <https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7509-E.pdf> (accessed Mar. 27, 2025).
[38] PG&E AL 7204-E, available at: <https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7204-E.pdf> (accessed Mar. 27, 2025).
[39] PG&E AL 7204-E-A, available at: <https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7204-E-A.pdf> (accessed Mar. 27, 2025).
[40] PG&E AL 7531-E, available at: <https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7531-E.pdf> (accessed Mar. 27, 2025).

Chapter 10 (Joint Investor-Owned Utility Non-Bypassable Charge Proposal) is co-sponsored by PG&E, SCE, and SDG&E and presents the ratemaking mechanism for the statewide NBC applicable to all Commission-jurisdictional customers through the PPP rates of the Commission-jurisdictional IOUs. PG&E, SCE, and SDG&E jointly present testimony to allocate the net revenue requirement for the Record Period amongst themselves using the California Energy Commission's ("CEC") published 2025 peak load forecast that is developed for use in the Commission's RA program. Each utility sponsors its own testimony on allocating its share of the revenue requirement among its customer classes using a process that mirrors the existing Cost Allocation Methodology for system reliability resources.

Chapter 10 also presents the allocation of the DCPP Extended Operations revenue requirement to PG&E, SCE, and SDG&E and illustrative DCNBC rates applicable to customers in each utility's service area based on the methodology adopted by D.23-12-036. The rates presented in Chapter 10 are illustrative and subject to updates in the Fall Update and in each utility's January 1, 2026, consolidated rate change process.

Appendix A includes the statements of qualification for PG&E, SCE, and SDG&E witnesses sponsoring this Prepared Testimony. Parties that execute a Non-Disclosure Agreement with PG&E are able to receive the confidential version of PG&E's workpapers, data request responses, and other items, if any, throughout the course of this proceeding.

V. FALL UPDATE

Similar to the rate recovery process in existence for the large IOUs for the ERRA proceedings, PG&E will update its prepared testimony in October 2025 (i.e., the Fall Update) to include any updated forecast and recorded DCEOBA balances prior to the issuance of the proposed decision.[41] Certain variable factors that will be available during the Fall Update include but are not limited to: (1) the final RA market price benchmarks used to charge

[41] A subsequent true-up of the 2025 forecast revenue requirement and rates to actual costs, PG&E billed revenues, IOU remitted revenues, and CAISO market revenues will occur through an expedited Tier 3 advice letter process.

replacement capacity, (2) updated forward CAISO market prices that will be used to offset costs, and (3) more historical information to confirm the expected over or undercollection from the IOUs. This year, PG&E will provide a forecast of the expected end-of-year DCEOBA balances as part of its Fall Update testimony.[42] PG&E also will present the amortization of the 2025 balancing account balances into rates as of January 1, 2026. The over or undercollection of 2025 rates will be included in the December 2025 AET for ratesetting purposes. Therefore, as explained above in the Introduction, timely approval of this proceeding is essential to avoid a systemic mismatch in timing between the forecast period and the time at which the recorded costs, market revenues, and billed/remitted revenues are recovered in rates. Finally, PG&E proposes to update its 2026 Record Period revenue requirement to reflect $12.5 million DOE settlement claims proceeds for DCPP spent fuel management activities funded through the DCEOBA.

VI. COMPLIANCE WITH THE COMMISSION'S RULES OF PRACTICE AND PROCEDURE

A. Statutory and Other Authority (Rule 2.1)

PG&E files this Application pursuant to Rules 2.1 and 3.2, as well as Rule 2.2, § 712.8(h)(1) and D.23-12-036.

B. Legal Name and Principal Place of Business (Rule 2.1(a))

The legal name of the Applicant is Pacific Gas and Electric Company. PG&E's principal place of business is 300 Lakeside Drive, Oakland, California 94612. PG&E is duly organized under the State of California.

C. Correspondence and Communications (Rule 2.1(b))

All correspondence, communications, and service of papers regarding this Application should be directed to:

[42] Any under- or over-collected DCEOBA balances would become part of the subsequent year revenue requirement, since D.23-12-036 does not contemplate a process for adjusting rates mid-year.

Lillian Rafii Pacific Gas and Electric Company 300 Lakeside Drive Attn: Law Department Oakland, CA 94612	Thomas Jarman Pacific Gas and Electric Company 300 Lakeside Drive Attn: Regulatory Affairs Department Oakland, CA 94612
Telephone: (510) 203-0749 E-Mail: Lillian.Rafii@pge.com	E-mail: Thomas.Jarman@pge.com

D. Categorization, Hearings, and Issues to Be Considered (Rule 2.1(c))

1. Proposed Categorization

This application should be categorized as a "ratesetting" proceeding.

2. Need for Hearings

PG&E anticipates that evidentiary hearings may be requested by other parties to this proceeding, but the need for evidentiary hearings will depend on the degree to which and grounds on which other parties might contest the proposals contained in this application. PG&E hopes to resolve the issues raised in this application without hearings, such as through more informal procedures, including discovery.

3. Issues to Be Considered

The issues presented in this application are as follows:

1. Whether PG&E's forecast cost of operations and revenue requirement over the Record Period for DCPP is just and reasonable?
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?
3. Whether PG&E's proposed modification to the 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 PG&E's planned expenditure of VPFs during the January 1 to December 31, 2026, period comply with § 712.8(s)(1) requirements?

E. Procedural Schedule

PG&E proposes the following procedural schedule for this proceeding, which results in a final decision at the first voting meeting in December 2025, to facilitate the ratemaking process among the statewide IOUs.

Event	Date (all in 2025)
PG&E files Application	March 28
Notice of Application appears in Daily Calendar	April 1
Protests filed	+ 30 days after Notice
Reply filed	+ 10 days after Protests/ Responses
Prehearing Conference	By May 30
Intervenor testimony served	July 8
Rebuttal testimony served	August 15
Rule 13.9 Meet and Confer	By August 25
Evidentiary Hearings (if needed)	Week of September 8
Opening Briefs	October 1
Market Price Benchmarks issued	October 1
Update to Prepared Testimony ("Fall Update") served	By October 8
Comments to Fall Update	October 20
Reply Briefs	October 27
Reply comments to Fall Update; proceeding submitted	October 31
Proposed Decision issued 20 days before Commission voting meeting	November
Comments on Proposed Decision	+ 5 days after Proposed Decision[a]
Reply Comments	+ 3 days after Comments on Proposed Decision[a]
Final Decision	December 4

> (a) Rule 14.6(b) allows the parties in the proceeding to stipulate to a shortened comment period. In the past, parties to PG&E's annual ERRA Forecast proceedings have stipulated to a shortened comment period given the timing constraints between the anticipated Proposed Decision date and the need for a January rate change.

The proposed schedule adheres to D.23-12-036 and is consistent with the ERRA Forecast schedules, which it is modeled after.

F. Articles of Incorporation (Rule 2.2)

PG&E is, and since October 10, 1905, has been, an operating public utility corporation organized under California law. It is engaged principally in the business of furnishing electric and gas services in California. A certified copy of PG&E's Amended and Restated Articles of Incorporation, effective June 22, 2020, was filed with the Commission on July 1, 2020, with PG&E's Application ("A.") 20-07-002. These articles are incorporated herein by reference pursuant to Rule 2.2 of the Commission's Rules.

G. Authority to Increase Rates (Rule 3.2)

PG&E is providing material in this Application that complies with Rule 3.2. This Application is not a general rate increase application, so Rule 3.2(a) applies, except for subsections (4), (7), and (9).

H. Balance Sheet and Income Statement (Rule 3.2(a)(1))

Attachment A of this Application presents PG&E's most recent balance sheet and income statement for the period ended December 31, 2024.

I. Statement of Presently Effective Rates (Rule 3.2(a)(2))

PG&E's presently effective electric rates are attached as Attachment B to this Application.

J. Statement of Proposed Increases or Changes In Rates (Rule 3.2(a)(3))

The proposed changes in electric rates are set forth in Attachment C.

K. Summary of Earnings (Rule 3.2(a)(5) and (a)(6))

A summary of recorded 2023 revenues, expenses, rate bases, and rate of return for

PG&E's Electric and Gas Departments was filed with the Commission on September 6, 2024, in first amended A.23-12-014, and is incorporated herein by reference.

L. Most Recent Proxy Statement – Rule 3.2(a)(8)

PG&E's most recent proxy statement was filed with the Commission on May 15, 2024, in A.24-05-009. This proxy statement is incorporated herein by reference.

M. Type of Rate Change Requested (Rule 3.2(a)(10))

The rate changes sought in this application pass through to PG&E, SCE, and SDG&E customers in their respective PPP rates as a non-bypassable charge.

N. Service and Notice of Application (Rule 3.2(b)-(d))

PG&E is serving this Application and its prepared testimony on the service lists in: *Application of Pacific Gas and Electric Company to Recover in Customer Rates the Costs to Support Extended Operation of Diablo Canyon Power Plant from September 1, 2023 through December 31, 2025 and for Approval of Planned Expenditure of 2025 Volumetric Performance Fees, A.24-03-018* and *Order Instituting Rulemaking to Consider Potential Extension of Diablo Canyon Power Plant Operations in Accordance with Senate Bill 846, R.23-01-007*. Within 20 days after filing this Application, PG&E will mail a notice stating in general terms the proposed revenues, rate changes and rate making mechanisms requested in this Application to the parties listed in Attachment D of this Application, including the State of California and cities and counties served by PG&E. Within 20 days, PG&E will also publish in newspapers of general circulation in each county in its service territory a notice of the filing of this Application and any proposed changes in rates.

Within 45 days after filing this Application, PG&E will also include notices of proposed changes in rates with the regular bills mailed or emailed to all customers affected by the proposed changes.

O. Safety (Rule 2.1(c))

In D.16-01-017, the Commission adopted an amendment to Rule 2.1(c) requiring applications to clearly state the "relevant safety considerations." The Commission has previously explained that the "safe and reliable provisions of utilities at predictable rates promotes public safety."[43] As demonstrated in this application and the prepared testimony, the proposals in this proceeding support the directives provided in SB 846, which find that extending DCPP operations is "prudent, cost effective, and in the best interests of all California electricity customers."[44] PG&E is providing detailed testimony and workpapers supporting its revenue requirement for the Record Period. The rate proposals contained in this application are co-sponsored by PG&E, SCE, and SDG&E pursuant to D.23-12-036. The proposals in this proceeding will promote the safe and reliable provision of electric service and establish predictable rates, all of which can help facilitate public safety.

VII. ATTACHMENTS

The following attachments are included in this Application:

- Attachment A – Balance sheet and income statement;
- Attachment B – Present electric rates;
- Attachment C – Proposed rate decrease; and
- Attachment D – City and county mailing list.

VIII. CONCLUSION

PG&E respectfully requests that the Commission issue an order in this application to authorize the following:

1. DCPP revenue requirement from the Record Period of $410 million to be effective in rates on January 1, 2026, including the following forecasts and their underlying financial assumptions and calculations, subject to updates in the Fall Update:
   a. Operations and maintenance costs (including expenses, project costs, and statutory costs and fees, as well as associated escalation),
   b. Charges for the liquidated damages account pursuant to Section 712.8(g),
   c. Resource Adequacy substitution capacity costs, including any updates from the results of R.25-02-005, or unless otherwise directed by the Commission,
   d. Operating expenses that would be amortized through 2030 (i.e., nuclear fuel

[43] D.14-12-053, pp. 12-13.
[44] Pub. Res. Code, § 25548(b).

procurement), and

e. Netting of CAISO revenues for the period from January 1, 2026, to December 31, 2026.

2. The statewide Diablo Canyon Non-Bypassable Charge.

3. Modification of the DOELBA preliminary statement to create a sub-account for spent nuclear claim proceeds attributable to the DCEOBA, to be implemented in a Tier 1 advice letter within 60 days following the issuance of the decision.

4. PG&E's 2026 VPF plan and proposed spending priorities for the expenditures.

5. Find that PG&E's testimony satisfies all the regulatory requirements from D.23-12-036 and D.24-12-033.

Respectfully Submitted,

By: */s/ Lillian Rafii*
LILLIAN RAFII

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E-Mail: Lillian.Rafii@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: March 28, 2025

ATTACHMENT A

ATTACHMENT B

ATTACHMENT C

VERIFICATION

I, the undersigned, say:

I am an officer of Pacific Gas and Electric Company, a corporation, and am authorized, pursuant to Rule 2.1 and Rule 1.11 of the Rules of Practice and Procedure of the Commission, to make this Verification for and on behalf of said Corporation, and I make this Verification for that reason. I have read the foregoing Application, and I am informed and believe that the matters therein concerning Pacific Gas and Electric Company are true.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct to the best of my knowledge.

Executed on 03/27/2025, at San Luis Obispo, California.

By: *_/s Maureen Zawalick_*
Maureen Zawalick
Vice President, Business & Technical Services

ATTACHMENT A

PACIFIC GAS AND ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF INCOME
(in millions)

	Year ended December 31,		
	2024	**2023**	**2022**
Operating Revenues			
Electric	$ 17,811	$ 17,424	$ 15,060
Natural gas	6,608	7,004	6,620
Total operating revenues	**24,419**	**24,428**	**21,680**
Operating Expenses			
Cost of electricity	2,261	2,443	2,756
Cost of natural gas	1,192	1,754	2,100
Operating and maintenance	11,787	11,913	9,725
SB 901 securitization charges, net	33	1,267	608
Wildfire-related claims, net of recoveries	94	64	237
Wildfire Fund expense	383	567	477
Depreciation, amortization, and decommissioning	4,189	3,738	3,856
Total operating expenses	**19,939**	**21,746**	**19,759**
Operating Income	**4,480**	**2,682**	**1,921**
Interest income	589	593	162
Interest expense	(2,781)	(2,485)	(1,658)
Other income, net	319	293	595
Income Before Income Taxes	**2,607**	**1,083**	**1,020**
Income tax benefit	(105)	(1,461)	(1,206)
Net Income	**2,712**	**2,544**	**2,226**
Preferred stock dividend requirement	14	14	14
Income Available for Common Stock	**$ 2,698**	**$ 2,530**	**$ 2,212**

See accompanying Notes to the Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in millions)

	Year ended December 31,		
	2024	**2023**	**2022**
Net Income	**$ 2,712**	**$ 2,544**	**$ 2,226**
Other Comprehensive Income (Loss)			
Pension and other postretirement benefit plans obligations (net of taxes of \$3, \$5, and \$2, at respective dates)	(8)	(12)	6
Net unrealized gain (losses) on available-for-sale securities (net of taxes of \$0, \$4, and \$3, respectively)	1	7	(5)
Total other comprehensive income (loss)	**(7)**	**(5)**	**1**
Comprehensive Income	**$ 2,705**	**$ 2,539**	**$ 2,227**

See accompanying Notes to the Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS
(in millions)

	Balance at	
	December 31, 2024	**December 31, 2023**
ASSETS		
Current Assets		
Cash and cash equivalents	$ 705	$ 442
Restricted cash and restricted cash equivalents (includes $263 million and $282 million related to VIEs at respective dates)	272	294
Accounts receivable		
Customers (net of allowance for doubtful accounts of $418 million and $445 million at respective dates) (includes $1.9 billion and $1.7 billion related to VIEs, net of allowance for doubtful accounts of $418 million and $445 million at respective dates)	2,220	2,048
Accrued unbilled revenue (includes $1.3 billion and $1.1 billion related to VIEs at respective dates)	1,487	1,254
Regulatory balancing accounts	7,227	5,660
Other (net of allowance for doubtful accounts of $35 million and $35 million at respective dates)	1,810	1,495
Regulatory assets	234	300
Inventories		
Gas stored underground and fuel oil	52	65
Materials and supplies	768	805
Wildfire Fund asset	301	450
Wildfire self-insurance asset	905	—
Other	998	1,374
Total current assets	**16,979**	**14,187**
Property, Plant, and Equipment		
Electric	86,639	80,345
Gas	31,623	29,830
Construction work in progress	4,458	4,452
Financing lease ROU asset and other	814	787
Total property, plant, and equipment	**123,534**	**115,414**
Accumulated depreciation	(35,304)	(33,093)
Net property, plant, and equipment	**88,230**	**82,321**
Other Noncurrent Assets		
Regulatory assets	15,561	17,189
Customer credit trust	377	233
Nuclear decommissioning trusts	3,833	3,574
Operating lease ROU asset	519	598
Wildfire Fund asset	4,070	4,297
Income taxes receivable	—	22
Other (includes noncurrent accounts receivable of $82 million and $0 related to VIEs, net of noncurrent allowance for doubtful accounts of $18 million and $0 at respective dates)	3,697	2,934
Total other noncurrent assets	**28,057**	**28,847**
TOTAL ASSETS	**$ 133,266**	**$ 125,355**

See accompanying Notes to the Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS
(in millions, except share amounts)

	Balance at	
	December 31, 2024	**December 31, 2023**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$ 1,523	$ 3,971
Long-term debt, classified as current (includes $222 million and $176 million related to VIEs at respective dates)	2,146	1,376
Accounts payable		
Trade creditors	2,745	2,307
Regulatory balancing accounts	3,169	1,669
Other	729	820
Operating lease liabilities	85	80
Financing lease liabilities	577	259
Interest payable (includes $91 million and $67 million related to VIEs at respective dates)	667	621
Wildfire-related claims	916	1,422
Other	3,331	4,391
Total current liabilities	**15,888**	**16,916**
Noncurrent Liabilities		
Long-term debt (includes $10.1 billion and $10.5 billion related to VIEs at respective dates)	47,958	46,376
Regulatory liabilities	19,417	19,444
Pension and other postretirement benefits	741	405
Asset retirement obligations	5,444	5,512
Deferred income taxes	3,632	2,436
Operating lease liabilities	434	518
Financing lease liabilities	4	554
Other	4,198	3,670
Total noncurrent liabilities	**81,828**	**78,915**
Shareholders' Equity		
Preferred stock	258	258
Common stock, $5 par value, authorized 800,000,000 shares; 800,000,000 shares outstanding at respective dates	1,322	1,322
Additional paid-in capital	35,930	30,570
Reinvested earnings	(1,940)	(2,613)
Accumulated other comprehensive loss	(20)	(13)
Total shareholders' equity	**35,550**	**29,524**
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**$ 133,266**	**$ 125,355**

See accompanying Notes to the Consolidated Financial Statements.

ATTACHMENT B

Exhibit B

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Saturday, March 1, 2025

RESIDENTIAL RATES

LINE NO.		3/1/25 RATES SUMMER	3/1/25 RATES WINTER	LINE NO.
1	SCHEDULE E-1			1
2	MINIMUM BILL ($/MONTH)	$12.27	$12.27	2
3	ES UNIT DISCOUNT ($/UNIT/MONTH)	$0.82	$0.82	3
4	ET UNIT DISCOUNT ($/UNIT/MONTH)	$3.54	$3.54	4
5	ES/ET MINIMUM RATE LIMITER ($/KWH)	$0.04892	$0.04892	5
6	ENERGY ($/KWH)			6
7	TIER 1 (Baseline Quantity - BQ)	$0.40730	$0.40730	7
8	TIER 2 - All usage > 100% of BQ	$0.51031	$0.51031	8
9	SCHEDULE E-TOU-C (Default TOU Rate for E-1 Customers)			9
10	MINIMUM BILL ($/MONTH)	$12.27	$12.27	10
11	ON-PEAK ENERGY ($/KWH)	$0.62569	$0.50086	11
12	PART-PEAK ENERGY ($/KWH)	$0.50269	$0.47086	12
13	BASELINE CREDIT ($/KWH)	($0.10301)	($0.10301)	13
14	SCHEDULE EM-TOU			14
15	MINIMUM BILL ($/MONTH)	$12.27	$12.27	15
16	METER CHARGE ($/MONTH)	$7.70	$7.70	16
17	ON-PEAK ENERGY ($/KWH)			17
18	TIER 1 (Baseline Quantity - BQ)	$0.52268	n/a	18
19	TIER 2 - All usage > 100% of BQ	$0.62569	n/a	19
20	PART-PEAK ENERGY ($/KWH)			20
21	TIER 1 (Baseline Quantity - BQ)	$0.00000	$0.39785	21
22	TIER 2 - All usage > 100% of BQ	$0.00000	$0.50086	22
23	OFF-PEAK ENERGY ($/KWH)			23
24	TIER 1 (Baseline Quantity - BQ)	$0.39968	$0.36785	24
25	TIER 2 - All usage > 100% of BQ	$0.50269	$0.47086	25

Exhibit B

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Saturday, March 1, 2025

OPTIONAL RESIDENTIAL RATES

LINE NO.		3/1/25 RATES SUMMER	3/1/25 RATES WINTER	LINE NO.
1	D-CARE (Previously Low Income "L" Rates)			1
2	MINIMUM BILL ($/MONTH) - 50% DISCOUNT	$6.14	$6.14	2
3	EML-TOU METER CHARGE($/MONTH)	$0.00	$0.00	3
4	BASE SERVICES CHARGE ($/MONTH) - 50% DISCOUNT	$7.50	$7.50	4
5	ALL ENERGY (% DISCOUNT)	-35.00%	-35.00%	5
6	SCHEDULE E-TOU-B			6
7	MINIMUM BILL ($/MONTH)	$12.27	$12.27	7
8	ON-PEAK ENERGY ($/KWH)	$0.58672	$0.45009	8
9	OFF-PEAK ENERGY ($/KWH)	$0.46366	$0.41129	9
10	SCHEDULE E-TOU-D			10
11	MINIMUM BILL ($/MONTH)	$12.27	$12.27	11
12	ON-PEAK ENERGY ($/KWH)	$0.57149	$0.48189	12
13	OFF-PEAK ENERGY ($/KWH)	$0.43653	$0.44328	13
14	SCHEDULE E-ELEC			14
15	BASE SERVICES CHARGE ($/MONTH)	$15.00	$15.00	15
16	ON-PEAK ENERGY ($/KWH)	$0.61418	$0.38266	16
17	PART-PEAK ENERGY ($/KWH)	$0.45230	$0.36057	17
18	OFF-PEAK ENERGY ($/KWH)	$0.39562	$0.34671	18
19	SCHEDULE EV: RATE A			19
20	MINIMUM BILL ($/MONTH)	$12.27	$12.27	20
21	ON-PEAK ENERGY ($/KWH)	$0.72891	$0.54631	21
22	PART-PEAK ENERGY ($/KWH)	$0.48480	$0.41430	22
23	OFF-PEAK ENERGY ($/KWH)	$0.37225	$0.34257	23
24	SCHEDULE EV: RATE B			24
25	EV-B METER CHARGE ($/MONTH)	$1.50	$1.50	25
26	ON-PEAK ENERGY ($/KWH)	$0.72572	$0.54318	26
27	PART-PEAK ENERGY ($/KWH)	$0.48161	$0.41117	27
28	OFF-PEAK ENERGY ($/KWH)	$0.36906	$0.33944	28
29	SCHEDULE EV2: RATE A			29
30	MINIMUM BILL ($/MONTH)	$12.27	$12.27	30
31	ON-PEAK ENERGY ($/KWH)	$0.62277	$0.49566	31
32	PART-PEAK ENERGY ($/KWH)	$0.51228	$0.47896	32
33	OFF-PEAK ENERGY ($/KWH)	$0.31026	$0.31027	33

Exhibit B

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Saturday, March 1, 2025

SMALL L&P RATES

LINE NO.		3/1/25 RATES SUMMER	3/1/25 RATES WINTER	LINE NO.
1	SCHEDULE A-1			1
2	CUSTOMER CHARGE: SINGLE-PHASE ($/MO.)	$10.00	$10.00	2
3	CUSTOMER CHARGE: POLYPHASE ($/MO.)	$25.00	$25.00	3
4	ENERGY ($/KWH)	$0.46240	$0.40542	4
5	SCHEDULE A-1 TOU			5
6	CUSTOMER CHARGE: SINGLE-PHASE ($/MO.)	$10.00	$10.00	6
7	CUSTOMER CHARGE: POLYPHASE ($/MO.)	$25.00	$25.00	7
8	ENERGY ($/KWH)			8
9	ON-PEAK	$0.46509		9
10	PART-PEAK	$0.46509	$0.41750	10
11	OFF-PEAK	$0.44038	$0.41692	11
12	SCHEDULE A-6			12
13	CUSTOMER CHARGE: SINGLE-PHASE ($/MO.)	$10.00	$10.00	13
14	CUSTOMER CHARGE: POLYPHASE ($/MO.)	$25.00	$25.00	14
18	ENERGY ($/KWH)			18
19	ON-PEAK	$0.52308		19
20	PART-PEAK	$0.48157	$0.42004	20
21	OFF-PEAK	$0.42909	$0.41900	21
22	SCHEDULE A-15			22
23	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	23
24	FACILITY CHARGE ($/MONTH)	$25.00	$25.00	24
25	ENERGY ($/KWH)	$0.46161	$0.42092	25
26	SCHEDULE TC-1			26
27	CUSTOMER CHARGE ($/MONTH)	$15.00	$15.00	27
28	ENERGY ($/KWH)	$0.37851	$0.37851	28

Exhibit B

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Saturday, March 1, 2025

SMALL L&P RATES

LINE NO.		3/1/25 RATES SUMMER	3/1/25 RATES WINTER	LINE NO.
1	SCHEDULE B-1			1
2	CUSTOMER CHARGE: SINGLE-PHASE ($/MO.)	$10.00	$10.00	2
3	CUSTOMER CHARGE: POLYPHASE ($/MO.)	$25.00	$25.00	3
4	ENERGY ($/KWH)			4
5	ON-PEAK	$0.51044	$0.43502	5
6	PART-PEAK	$0.46121		6
7	OFF-PEAK	$0.44040	$0.41890	7
8	SUPER OFF-PEAK		$0.40248	8
9	SCHEDULE B-6			9
10	CUSTOMER CHARGE: SINGLE-PHASE ($/MO.)	$10.00	$10.00	10
11	CUSTOMER CHARGE: POLYPHASE ($/MO.)	$25.00	$25.00	11
12	ENERGY ($/KWH)			12
13	ON-PEAK	$0.68214	$0.43545	13
14	OFF-PEAK	$0.42452	$0.39186	14
15	SUPER OFF-PEAK		$0.35578	15

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Saturday, March 1, 2025

MEDIUM L&P RATES

LINE NO.		3/1/25 RATES SUMMER	3/1/25 RATES WINTER	LINE NO.
1	SCHEDULE A-10			1
2	CUSTOMER CHARGE ($/MONTH)	$371.42	$371.42	2
3	MAXIMUM DEMAND CHARGE ($/KW/MO)			3
4	SECONDARY VOLTAGE	$25.69	$25.69	4
5	PRIMARY VOLTAGE	$24.84	$24.84	5
6	TRANSMISSION VOLTAGE	$13.95	$13.95	6
7	ENERGY CHARGE ($/KWH)			7
8	SECONDARY VOLTAGE	$0.28325	$0.24565	8
9	PRIMARY VOLTAGE	$0.25934	$0.22414	9
10	TRANSMISSION VOLTAGE	$0.17083	$0.15370	10
11	SCHEDULE A-10 TOU			11
12	CUSTOMER CHARGE ($/MONTH)	$371.42	$371.42	12
13	MAXIMUM DEMAND CHARGE ($/KW/MO)			13
14	SECONDARY VOLTAGE	$25.69	$25.69	14
15	PRIMARY VOLTAGE	$24.84	$24.84	15
16	TRANSMISSION VOLTAGE	$13.95	$13.95	16
17	ENERGY CHARGE ($/KWH)			17
18	SECONDARY			18
19	ON PEAK	$0.29701		19
20	PARTIAL PEAK	$0.29701	$0.24655	20
21	OFF-PEAK	$0.27023	$0.24584	21
22	PRIMARY			22
23	ON PEAK	$0.27383		23
24	PARTIAL PEAK	$0.27383	$0.22471	24
25	OFF-PEAK	$0.24851	$0.22404	25
26	TRANSMISSION			26
27	ON PEAK	$0.18597		27
28	PARTIAL PEAK	$0.18597	$0.15408	28
29	OFF-PEAK	$0.16132	$0.15342	29
30	SCHEDULE B-10			30
31	CUSTOMER CHARGE ($/MONTH)	$371.42	$371.42	31
32	MAXIMUM DEMAND CHARGE ($/KW/MO)			32
33	SECONDARY VOLTAGE	$22.71	$22.71	33
34	PRIMARY VOLTAGE	$21.89	$21.89	34
35	TRANSMISSION VOLTAGE	$14.21	$14.21	35
36	ENERGY CHARGE ($/KWH)			36
37	SECONDARY			37
38	ON-PEAK	$0.36806	$0.29179	38
39	PART-PEAK	$0.30637		39
40	OFF-PEAK	$0.27380	$0.25631	40
41	SUPER OFF-PEAK		$0.21997	41
42	PRIMARY			42
43	ON-PEAK	$0.34209	$0.26924	43
44	PART-PEAK	$0.28379		44
45	OFF-PEAK	$0.25295	$0.23560	45
46	SUPER OFF-PEAK		$0.19926	46
47	TRANSMISSION			47
48	ON-PEAK	$0.23643	$0.18338	48
49	PART-PEAK	$0.17969		49
50	OFF-PEAK	$0.14962	$0.15055	50
51	SUPER OFF-PEAK		$0.11421	51

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Saturday, March 1, 2025

E-19 FIRM RATES

LINE NO.		3/1/25 RATES SUMMER	3/1/25 RATES WINTER	LINE NO.
1	SCHEDULE E-19 T FIRM			1
2	CUSTOMER CHARGE > 500 KW ($/MONTH)	$3,637.59	$3,637.59	2
3	CUSTOMER CHARGE < 500 KW ($/MONTH)	$371.42	$371.42	3
4	TOU METER CHARGE - RATES V & X ($/MONTH)	$371.42	$371.42	4
5	TOU METER CHARGE - RATE W ($/MONTH)	$371.42	$371.42	5
6	DEMAND CHARGE ($/KW/MONTH)			6
7	ON-PEAK	$17.74		7
8	PARTIAL PEAK	$17.74	$0.00	8
9	MAXIMUM	$18.47	$18.47	9
10	ENERGY CHARGE ($/KWH)			10
11	ON-PEAK	$0.10987		11
12	PARTIAL-PEAK	$0.10987	$0.09918	12
13	OFF-PEAK	$0.10239	$0.09831	13
14	SCHEDULE E-19 P FIRM			14
15	CUSTOMER CHARGE > 500 KW ($/MONTH)	$2,761.98	$2,761.98	15
16	CUSTOMER CHARGE < 500 KW ($/MONTH)	$371.42	$371.42	16
17	TOU METER CHARGE - RATES V & X ($/MONTH)	$371.42	$371.42	17
18	TOU METER CHARGE - RATE W ($/MONTH)	$371.42	$371.42	18
19	DEMAND CHARGE ($/KW/MONTH)			19
20	ON-PEAK	$22.84		20
21	PARTIAL PEAK	$18.82	$0.00	21
22	MAXIMUM	$35.50	$35.50	22
23	ENERGY CHARGE ($/KWH)			23
24	ON-PEAK	$0.12246		24
25	PARTIAL-PEAK	$0.12246	$0.11209	25
26	OFF-PEAK	$0.11522	$0.11124	26
27	SCHEDULE E-19 S FIRM			27
28	CUSTOMER CHARGE > 500 KW ($/MONTH)	$1,863.65	$1,863.65	28
29	CUSTOMER CHARGE < 500 KW ($/MONTH)	$371.42	$371.42	29
30	TOU METER CHARGE - RATES V & X ($/MONTH)	$371.42	$371.42	30
31	TOU METER CHARGE - RATE W ($/MONTH)	$371.42	$371.42	31
32	DEMAND CHARGE ($/KW/MONTH)			32
33	ON-PEAK	$26.79		33
34	PARTIAL PEAK	$21.30	$0.00	34
35	MAXIMUM	$45.68	$45.68	35
36	ENERGY CHARGE ($/KWH)			36
37	ON-PEAK	$0.13862		37
38	PARTIAL-PEAK	$0.13862	$0.12790	38
39	OFF-PEAK	$0.13114	$0.12701	39

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Saturday, March 1, 2025

B-19 FIRM RATES

LINE NO.		3/1/25 RATES SUMMER	3/1/25 RATES WINTER	LINE NO.
1	SCHEDULE B-19 T FIRM			1
2	CUSTOMER CHARGE ($/MONTH)	$3,933.20	$3,933.20	2
3	TOU METER CHARGE - RATE V ($/MONTH)	$371.42	$371.42	3
4	DEMAND CHARGE ($/KW/MONTH)			4
5	ON-PEAK	$20.36	$1.96	5
6	PARTIAL PEAK	$5.09		6
7	MAXIMUM	$19.11	$19.11	7
8	ENERGY CHARGE ($/KWH)			8
9	ON-PEAK	$0.16828	$0.16711	9
10	PARTIAL-PEAK	$0.15098		10
11	OFF-PEAK	$0.11416	$0.11497	11
12	SUPER OFF-PEAK		$0.03828	12
13	SCHEDULE B-19 P FIRM			13
14	CUSTOMER CHARGE ($/MONTH)	$2,860.38	$2,860.38	14
15	TOU METER CHARGE - RATE V ($/MONTH)	$371.42	$371.42	15
16	DEMAND CHARGE ($/KW/MONTH)			16
17	ON-PEAK	$45.80	$2.33	17
18	PARTIAL PEAK	$9.92		18
19	MAXIMUM	$32.00	$32.00	19
20	ENERGY CHARGE ($/KWH)			20
21	ON-PEAK	$0.18881	$0.16507	21
22	PARTIAL-PEAK	$0.14798		22
23	OFF-PEAK	$0.11247	$0.11291	23
24	SUPER OFF-PEAK		$0.03870	24
25	SCHEDULE B-19 S FIRM			25
26	CUSTOMER CHARGE ($/MONTH)	$1,920.94	$1,920.94	26
27	TOU METER CHARGE - RATE V ($/MONTH)	$371.42	$371.42	27
28	DEMAND CHARGE ($/KW/MONTH)			28
29	ON-PEAK	$55.76	$3.20	29
30	PARTIAL PEAK	$12.21		30
31	MAXIMUM	$40.90	$40.90	31
32	ENERGY CHARGE ($/KWH)			32
33	ON-PEAK	$0.21867	$0.18454	33
34	PARTIAL-PEAK	$0.16493		34
35	OFF-PEAK	$0.12692	$0.12677	35
36	SUPER OFF-PEAK		$0.04927	36

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Saturday, March 1, 2025

LARGE L&P RATES

LINE NO.		3/1/25 RATES SUMMER	3/1/25 RATES WINTER	LINE NO.
1	SCHEDULE E-20 T FIRM			1
2	CUSTOMER CHARGE ($/MONTH)-FIRM	$9,432.09	$9,432.09	2
3	DEMAND CHARGE ($/KW/MONTH)			3
4	ON-PEAK	$22.22		4
5	PARTIAL PEAK	$22.22	$0.00	5
6	MAXIMUM	$18.55	$18.55	6
7	ENERGY CHARGE ($/KWH)			7
8	ON-PEAK	$0.11402		8
9	PARTIAL-PEAK	$0.11402	$0.10359	9
10	OFF-PEAK	$0.10672	$0.10274	10
11	SCHEDULE E-20 P FIRM			11
12	CUSTOMER CHARGE ($/MONTH)	$3,487.67	$3,487.67	12
13	DEMAND CHARGE ($/KW/MONTH)			13
14	ON-PEAK	$27.51		14
15	PARTIAL PEAK	$22.10	$0.00	15
16	MAXIMUM	$40.96	$40.96	16
17	ENERGY CHARGE ($/KWH)			17
18	ON-PEAK	$0.12930		18
19	PARTIAL-PEAK	$0.12930	$0.11890	19
20	OFF-PEAK	$0.12202	$0.11805	20
21	SCHEDULE E-20 S FIRM			21
22	CUSTOMER CHARGE ($/MONTH)	$3,412.93	$3,412.93	22
23	DEMAND CHARGE ($/KW/MONTH)			23
24	ON-PEAK	$27.19		24
25	PARTIAL PEAK	$20.74	$0.00	25
26	MAXIMUM	$45.01	$45.01	26
27	ENERGY CHARGE ($/KWH)			27
28	ON-PEAK	$0.13075		28
29	PARTIAL-PEAK	$0.13075	$0.12020	29
30	OFF-PEAK	$0.12341	$0.11932	30

Exhibit B

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Saturday, March 1, 2025

LARGE L&P RATES

LINE NO.		3/1/25 RATES SUMMER	3/1/25 RATES WINTER	LINE NO.
1	SCHEDULE B-20 T FIRM			1
2	CUSTOMER CHARGE ($/MONTH)-FIRM	$10,844.16	$10,844.16	2
3	DEMAND CHARGE ($/KW/MONTH)			3
4	ON-PEAK	$30.09	$4.02	4
5	PARTIAL PEAK	$7.17		5
6	MAXIMUM	$19.41	$19.41	6
7	ENERGY CHARGE ($/KWH)			7
8	ON-PEAK	$0.17965	$0.17075	8
9	PARTIAL-PEAK	$0.14648		9
10	OFF-PEAK	$0.10945	$0.10380	10
11	SUPER OFF-PEAK		$0.03693	11
12	SCHEDULE B-20 P FIRM			12
13	CUSTOMER CHARGE ($/MONTH)	$3,620.40	$3,620.40	13
14	DEMAND CHARGE ($/KW/MONTH)			14
15	ON-PEAK	$53.64	$3.26	15
16	PARTIAL PEAK	$11.06		16
17	MAXIMUM	$37.86	$37.86	17
18	ENERGY CHARGE ($/KWH)			18
19	ON-PEAK	$0.20458	$0.17163	19
20	PARTIAL-PEAK	$0.15281		20
21	OFF-PEAK	$0.11671	$0.11680	21
22	SUPER OFF-PEAK		$0.03902	22
23	SCHEDULE B-20 S FIRM			23
24	CUSTOMER CHARGE ($/MONTH)	$3,524.92	$3,524.92	24
25	DEMAND CHARGE ($/KW/MONTH)			25
26	ON-PEAK	$50.19	$3.22	26
27	PARTIAL PEAK	$10.81		27
28	MAXIMUM	$43.05	$43.05	28
29	ENERGY CHARGE ($/KWH)			29
30	ON-PEAK	$0.20832	$0.17965	30
31	PARTIAL-PEAK	$0.16020		31
32	OFF-PEAK	$0.12220	$0.12189	32
33	SUPER OFF-PEAK		$0.04451	33

Exhibit B

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Saturday, March 1, 2025

STANDBY RATES

LINE NO.		3/1/25 RATES SUMMER	3/1/25 RATES WINTER	LINE NO.
1	SCHEDULE S - TRANSMISSION			1
2	CONTRACT CAPACITY CHARGE ($/KW/MO.)	$2.77	$2.77	2
3	EFFECTIVE RESERVATION CHARGE ($/KW/MO.)	$2.35	$2.35	3
4	ENERGY ($/KWH)			4
5	ON-PEAK	$0.18360		5
6	PART-PEAK	$0.15490	$0.15941	6
7	OFF-PEAK	$0.11693	$0.13025	7
8	SCHEDULE S - PRIMARY			8
9	CONTRACT CAPACITY CHARGE ($/KW/MO.)	$17.59	$17.59	9
10	EFFECTIVE RESERVATION CHARGE ($/KW/MO.)	$14.95	$14.95	10
11	ENERGY ($/KWH)			11
12	ON-PEAK	$1.35950		12
13	PART-PEAK	$0.57055	$0.24605	13
14	OFF-PEAK	$0.17215	$0.19106	14
15	SCHEDULE S - SECONDARY			15
16	CONTRACT CAPACITY CHARGE ($/KW/MO.)	$17.59	$17.59	16
17	EFFECTIVE RESERVATION CHARGE ($/KW/MO.)	$14.95	$14.95	17
18	ENERGY ($/KWH)			18
19	ON-PEAK	$1.35617		19
20	PART-PEAK	$0.56722	$0.24272	20
21	OFF-PEAK	$0.16882	$0.18773	21

Exhibit B

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Saturday, March 1, 2025

STANDBY RATES

LINE NO.		3/1/25 RATES SUMMER	3/1/25 RATES WINTER	LINE NO.
1	SCHEDULE S CUSTOMER AND METER CHARGES			1
2	RESIDENTIAL			2
3	CUSTOMER CHARGE ($/MO)	$5.00	$5.00	3
4	TOU METER CHARGE ($/MO)	$3.90	$3.90	4
5	AGRICULTURAL			5
6	CUSTOMER CHARGE ($/MO)	$27.60	$27.60	6
7	TOU METER CHARGE ($/MO)	$6.00	$6.00	7
8	SMALL LIGHT AND POWER (less than or equal to 75 kW)			8
9	SINGLE PHASE CUSTOMER CHARGE ($/MO)	$10.00	$10.00	9
10	POLY PHASE CUSTOMER CHARGE ($/MO)	$25.00	$25.00	10
11	METER CHARGE ($/MO)	$6.12	$6.12	11
12	MEDIUM LIGHT AND POWER (>75 kW, <500 kW)			12
13	CUSTOMER CHARGE ($/MO)	$371.42	$371.42	13
14	METER CHARGE ($/MO)	$5.40	$5.40	14
15	MEDIUM LIGHT AND POWER (>500kW, <1000kW)			15
16	TRANSMISSION CUSTOMER CHARGE ($/MO)	$3,637.59	$3,637.59	16
17	PRIMARY CUSTOMER CHARGE ($/MO)	$2,761.98	$2,761.98	17
18	SECONDARY CUSTOMER CHARGE ($/MO)	$1,863.65	$1,863.65	18
19	LARGE LIGHT AND POWER (> 1000 kW)			19
20	TRANSMISSION CUSTOMER CHARGE ($/MO)	$9,432.09	$9,432.09	20
21	PRIMARY CUSTOMER CHARGE ($/MO)	$3,487.67	$3,487.67	21
22	SECONDARY CUSTOMER CHARGE ($/MO)	$3,412.93	$3,412.93	22
23	REDUCED CUSTOMER CHARGES ($/MO)			23
24	SMALL LIGHT AND PWR (< 75 kW) SINGLE PHASE	$10.00	$10.00	24
25	MED LIGHT AND PWR (Res Capacity >75 kW and <500 kW) S	$37.57	$37.57	25
26	MED LIGHT AND PWR (Res Capacity > 500 kW and < 1000 kW) S	$240.93	$240.93	26

Exhibit B

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Saturday, March 1, 2025

STANDBY RATES

LINE NO.		3/1/25 RATES SUMMER	3/1/25 RATES WINTER	LINE NO.
1	SCHEDULE SB - TRANSMISSION			1
2	CONTRACT CAPACITY CHARGE ($/KW/MO.)	$2.47	$2.47	2
3	EFFECTIVE RESERVATION CHARGE ($/KW/MO.)	$2.10	$2.10	3
4	ENERGY ($/KWH)			4
5	ON-PEAK	$0.16376	$0.15906	5
6	PART-PEAK	$0.15179		6
7	OFF-PEAK	$0.13847	$0.13971	7
8	SUPER OFF-PEAK		$0.09549	8
9	SCHEDULE SB - PRIMARY			9
10	CONTRACT CAPACITY CHARGE ($/KW/MO.)	$17.90	$17.90	10
11	EFFECTIVE RESERVATION CHARGE ($/KW/MO.)	$15.22	$15.22	11
12	ENERGY ($/KWH)			12
13	ON-PEAK	$0.84105	$0.24396	13
14	PART-PEAK	$0.48596		14
15	OFF-PEAK	$0.21730	$0.21846	15
16	SUPER OFF-PEAK		$0.17431	16
17	SCHEDULE SB - SECONDARY			17
18	CONTRACT CAPACITY CHARGE ($/KW/MO.)	$17.90	$17.90	18
19	EFFECTIVE RESERVATION CHARGE ($/KW/MO.)	$15.22	$15.22	19
20	ENERGY ($/KWH)			20
21	ON-PEAK	$0.83772	$0.24063	21
22	PART-PEAK	$0.48263		22
23	OFF-PEAK	$0.21397	$0.21513	23
24	SUPER OFF-PEAK		$0.17098	24

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Saturday, March 1, 2025

STANDBY RATES

LINE NO.		3/1/25 RATES SUMMER	3/1/25 RATES WINTER	LINE NO.
1	SCHEDULE SB CUSTOMER CHARGES			1
2	RESIDENTIAL			2
3	CUSTOMER CHARGE ($/MO)	$5.00	$5.00	3
4	AGRICULTURAL			4
5	CUSTOMER CHARGE ($/MO)	$27.87	$27.87	5
6	SMALL LIGHT AND POWER (less than or equal to 50 kW)			6
7	SINGLE PHASE CUSTOMER CHARGE ($/MO)	$10.00	$10.00	7
8	POLY PHASE CUSTOMER CHARGE ($/MO)	$25.00	$25.00	8
9	MEDIUM LIGHT AND POWER (>75 kW, <500 kW)			9
10	CUSTOMER CHARGE ($/MO)	$371.42	$371.42	10
11	MEDIUM LIGHT AND POWER (>500kW, <1000kW)			11
12	TRANSMISSION CUSTOMER CHARGE ($/MO)	$3,933.20	$3,933.20	12
13	PRIMARY CUSTOMER CHARGE ($/MO)	$2,860.38	$2,860.38	13
14	SECONDARY CUSTOMER CHARGE ($/MO)	$1,920.94	$1,920.94	14
15	LARGE LIGHT AND POWER (> 1000 kW)			15
16	TRANSMISSION CUSTOMER CHARGE ($/MO)	$10,844.16	$10,844.16	16
17	PRIMARY CUSTOMER CHARGE ($/MO)	$3,620.40	$3,620.40	17
18	SECONDARY CUSTOMER CHARGE ($/MO)	$3,524.92	$3,524.92	18
19	REDUCED CUSTOMER CHARGES ($/MO)			19
20	SMALL LIGHT AND PWR (< 75 kW) SINGLE PHASE	$10.00	$10.00	20
21	MED LIGHT AND PWR (Res Capacity >75 kW and <500 kW) S	$37.57	$37.57	21
22	MED LIGHT AND PWR (Res Capacity > 500 kW and < 1000 kW) S	$240.93	$240.93	22

Exhibit B

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Saturday, March 1, 2025

AGRICULTURAL RATES

LINE NO.		3/1/25 RATES SUMMER	3/1/25 RATES WINTER	LINE NO.
1	SCHEDULE AG-1A			1
2	CUSTOMER CHARGE ($/MONTH)	$17.47	$17.47	2
3	CONNECTED LOAD CHARGE ($/hp/MONTH)	$14.23	$9.89	3
4	ENERGY CHARGE ($/KWH)	$0.35980	$0.31051	4
5	SCHEDULE AG-RA			5
6	CUSTOMER CHARGE - RATES A & D ($/MONTH)	$17.47	$17.47	6
9	CONNECTED LOAD CHARGE ($/hp/MONTH)	$11.60	$8.66	9
10	ENERGY ($/KWH)			10
11	ON-PEAK	$0.35328		11
12	PART-PEAK		$0.30560	12
13	OFF-PEAK	$0.35149	$0.30489	13
14	SCHEDULE AG-VA			14
15	CUSTOMER CHARGE - RATES A & D ($/MONTH)	$17.47	$17.47	15
18	CONNECTED LOAD CHARGE ($/hp/MONTH)	$11.29	$8.20	18
19	ENERGY ($/KWH)			19
20	ON-PEAK	$0.35842		20
21	PART-PEAK		$0.31031	21
22	OFF-PEAK	$0.35664	$0.30960	22
23	SCHEDULE AG-4A			23
24	CUSTOMER CHARGE - RATES A & D ($/MONTH)	$17.47	$17.47	24
27	CONNECTED LOAD CHARGE ($/hp/MONTH)	$12.06	$9.04	27
28	ENERGY ($/KWH)			28
29	ON-PEAK	$0.39671		29
30	PART-PEAK		$0.34135	30
31	OFF-PEAK	$0.39496	$0.34063	31
32	SCHEDULE AG-5A			32
33	CUSTOMER CHARGE - RATES A & D ($/MONTH)	$17.47	$17.47	33
36	CONNECTED LOAD CHARGE ($/hp/MONTH)	$21.03	$12.67	36
37	ENERGY ($/KWH)			37
38	ON-PEAK	$0.30724		38
39	PART-PEAK		$0.27481	39
40	OFF-PEAK	$0.30579	$0.27410	40

Exhibit B

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Saturday, March 1, 2025

AGRICULTURAL RATES

LINE NO.		3/1/25 RATES SUMMER	3/1/25 RATES WINTER	LINE NO.
1	SCHEDULE AG-1B			1
2	CUSTOMER CHARGE ($/MONTH)	$23.23	$23.23	2
3	MAXIMUM DEMAND CHARGE ($/KW/MONTH)			3
4	SECONDARY VOLTAGE	$23.75	$18.01	4
5	PRIMARY VOLTAGE DISCOUNT	$2.13	$1.56	5
6	ENERGY CHARGE ($/KWH)	$0.29477	$0.21408	6
7	SCHEDULE AG-RB			7
8	CUSTOMER CHARGE - RATES B & E ($/MONTH)	$23.23	$23.23	8
11	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$7.87		11
12	MAXIMUM DEMAND CHARGE ($/KW/MONTH)			12
13	SECONDARY VOLTAGE	$20.34	$16.19	13
14	PRIMARY VOLTAGE DISCOUNT	$0.78	$0.89	14
15	ENERGY CHARGE ($/KWH)			15
16	ON-PEAK	$0.33374		16
17	PART-PEAK		$0.30273	17
18	OFF-PEAK	$0.33213	$0.30202	18
19	SCHEDULE AG-VB			19
20	CUSTOMER CHARGE - RATES B & E ($/MONTH)	$23.23	$23.23	20
23	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$6.70		23
24	MAXIMUM DEMAND CHARGE ($/KW/MONTH)			24
25	SECONDARY VOLTAGE	$20.61	$16.65	25
26	PRIMARY VOLTAGE DISCOUNT	$1.07	$1.02	26
27	ENERGY CHARGE ($/KWH)			27
28	ON-PEAK	$0.31410		28
29	PART-PEAK		$0.28421	29
30	OFF-PEAK	$0.31247	$0.28350	30

Exhibit B

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Saturday, March 1, 2025

AGRICULTURAL RATES

LINE NO.		3/1/25 RATES SUMMER	3/1/25 RATES WINTER	LINE NO.
1	SCHEDULE AG-4B			1
2	CUSTOMER CHARGE - RATES B & E ($/MONTH)	$23.23	$23.23	2
5	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$4.50		5
6	MAXIMUM DEMAND CHARGE ($/KW/MONTH)			6
7	SECONDARY VOLTAGE	$21.25	$15.99	7
8	PRIMARY VOLTAGE DISCOUNT	$2.21	$0.99	8
9	ENERGY CHARGE ($/KWH)			9
10	ON-PEAK	$0.33508		10
11	PART-PEAK		$0.30421	11
12	OFF-PEAK	$0.33351	$0.24658	12
13	SCHEDULE AG-4C			13
14	CUSTOMER CHARGE - RATES C & F ($/MONTH)	$65.44	$65.44	14
17	DEMAND CHARGE ($/KW/MONTH)			17
18	ON-PEAK	$8.78		18
19	PART-PEAK	$7.77	$2.47	19
20	MAXIMUM	$16.99	$16.99	20
21	PRIMARY VOLTAGE DISCOUNT			21
22	ON-PEAK	$0.87		22
23	MAXIMUM		$0.73	23
24	TRANSMISSION VOLTAGE DISCOUNT			24
25	ON-PEAK	$3.23		25
26	PART-PEAK	$2.22	$2.47	26
27	MAXIMUM	$12.74	$12.74	27
28	ENERGY CHARGE ($/KWH)			28
29	ON-PEAK	$0.24711		29
30	PART-PEAK	$0.24658	$0.22393	30
31	OFF-PEAK	$0.23478	$0.22322	31
32	SCHEDULE AG-5B			32
33	CUSTOMER CHARGE - RATES B & E ($/MONTH)	$36.36	$36.36	33
36	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$10.94		36
37	MAXIMUM DEMAND CHARGE ($/KW/MONTH)			37
38	SECONDARY VOLTAGE	$31.69	$21.49	38
39	PRIMARY VOLTAGE DISCOUNT	$3.98	$0.74	39
40	TRANSMISSION VOLTAGE DISCOUNT	$15.58	$10.01	40
41	ENERGY CHARGE ($/KWH)			41
42	ON-PEAK	$0.22801		42
43	PART-PEAK		$0.21082	43
44	OFF-PEAK	$0.22725	$0.21014	44

Exhibit B

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Saturday, March 1, 2025

AGRICULTURAL RATES

LINE NO.		3/1/25 RATES SUMMER	3/1/25 RATES WINTER	LINE NO.
1	SCHEDULE AG-5C			1
2	CUSTOMER CHARGE - RATES C & F ($/MONTH)	$161.58	$161.58	2
5	DEMAND CHARGE ($/KW/MONTH)			5
6	ON-PEAK	$18.07		6
7	PART-PEAK	$15.99	$3.68	7
8	MAXIMUM	$15.60	$15.60	8
9	PRIMARY VOLTAGE DISCOUNT			9
10	ON-PEAK	$1.73		10
11	MAXIMUM		$1.37	11
12	TRANSMISSION VOLTAGE DISCOUNT			12
13	ON-PEAK	$6.62		13
14	PART-PEAK	$4.54	$0.00	14
15	MAXIMUM	$15.00	$15.00	15
16	ENERGY CHARGE ($/KWH)			16
17	ON-PEAK	$0.18896		17
18	PART-PEAK	$0.18854	$0.18147	18
19	OFF-PEAK	$0.18200	$0.18076	19

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Saturday, March 1, 2025

STREETLIGHTING RATES

LINE NO.		3/1/25 RATES SUMMER	3/1/25 RATES WINTER	LINE NO.
1	SCHEDULE LS-1			1
2	ENERGY CHARGE ($/KWH)	$0.35449	$0.35449	2
3	SCHEDULE LS-2			3
4	ENERGY CHARGE ($/KWH)	$0.35449	$0.35449	4
5	SCHEDULE LS-3			5
6	SERVICE CHARGE ($/METER/MO.)	$7.50	$7.50	6
7	ENERGY CHARGE ($/KWH)	$0.35449	$0.35449	7
8	SCHEDULE OL-1			8
9	ENERGY CHARGE ($/KWH)	$0.36730	$0.36730	9

ATTACHMENT C

Table 1
Pacific Gas and Electric Company
Illustrative Electric Revenue Increase and Class Average Rates
January - December 2026

Line No.	Customer Class	Proposed Revenue Increase (000's)	Present Rates ($/kWh)	Proposed Rates ($/kWh)	Percentage Change	Line No.
	Bundled Service*					
1	Residential	$ (16,845)	$ 0.36469	$ 0.36302	-0.5%	1
2	Small Commercial	$ (3,237)	$ 0.44151	$ 0.44016	-0.3%	2
3	Medium Commercial	$ (2,569)	$ 0.39120	$ 0.38998	-0.3%	3
4	Large Commercial	$ (4,100)	$ 0.34342	$ 0.34219	-0.4%	4
5	Streetlights	$ (98)	$ 0.47261	$ 0.47131	-0.3%	5
6	Standby	$ (586)	$ 0.18667	$ 0.18529	-0.7%	6
7	Agriculture	$ (5,563)	$ 0.39807	$ 0.39678	-0.3%	7
8	Industrial	$ (3,392)	$ 0.22714	$ 0.22617	-0.4%	8
9	Total	$ (36,389)	$ 0.35560	$ 0.35421	-0.4%	9
	Direct Access and Community Choice Aggregation Service**					
10	Residential	$ (29,882)	$ 0.23994	$ 0.23811	-0.8%	10
11	Small Commercial	$ (6,997)	$ 0.29772	$ 0.29635	-0.5%	11
12	Medium Commercial	$ (6,393)	$ 0.22833	$ 0.22711	-0.5%	12
13	Large Commercial	$ (13,581)	$ 0.18402	$ 0.18279	-0.7%	13
14	Streetlights	$ (217)	$ 0.29896	$ 0.29766	-0.4%	14
15	Standby	$ (207)	$ 0.13114	$ 0.12976	-1.1%	15
16	Agriculture	$ (2,004)	$ 0.24456	$ 0.24327	-0.5%	16
17	Industrial	$ (10,179)	$ 0.11217	$ 0.11120	-0.9%	17
18	Total	$ (69,461)	$ 0.20550	$ 0.20412	-0.7%	18
	Departing Load***					
19	Residential	$ (4)			-0.6%	19
20	Small Commercial	$ (14)			-3.1%	20
21	Medium Commercial	$ (88)			-4.0%	21
22	Large Commercial	$ (126)			-4.6%	22
23	Streetlights	$ -			0.0%	23
24	Standby	$ -			0.0%	24
25	Agriculture	$ (38)			-4.6%	25
26	Industrial	$ (1,527)			-4.0%	26

* Customers who receive electric generation as well as transmission and distribution service from PG&E.

** Customers who purchase energy from non-PG&E suppliers.

*** Customers who purchase their electricity from a non-utility supplier and receive transmission and distribution service from a publicly owned utility or municipality. A rate comparison cannot be provided for Departed Load as the applicable rates vary by specific departed load customer categories and any average rate that could be derived, would not be representative of any particular departed load category.

ATTACHMENT D

SERVICE OF NOTICE OF APPLICATION

In accordance with Rule 3.2(b), Applicant will mail a notice to the following, stating in general terms its proposed change in rates.

State of California

To the Attorney General and the Department of General Services.

State of California
Office of Attorney General
1300 I St Ste 1101
Sacramento, CA 95814

and

Director of General Services
State of California
707 3rd St
West Sacramento, CA 95605

Counties

To the County Counsel or District Attorney and the County Clerk in the following counties:

Alameda
Alpine
Amador
Butte
Calaveras
Colusa
Contra Costa
El Dorado
Fresno
Glenn
Humboldt
Kern
Kings
Lake
Lassen
Madera
Marin
Mariposa
Mendocino
Merced
Modoc
Monterey
Napa
Nevada
Placer
Plumas
Sacramento
San Benito
San Bernardino
San Francisco
San Joaquin
San Luis Obispo
San Mateo
Santa Barbara
Santa Clara
Santa Cruz
Shasta
Sierra
Siskiyou
Solano
Sonoma
Stanislaus
Sutter
Tehama
Trinity
Tulare
Tuolumne
Yolo
Yuba

Municipal Corporations

To the City Attorney and the City Clerk of the following municipal corporations:

Alameda
Albany
Amador City
American Canyon
Anderson
Angels Camp
Antioch
Arcata
Arroyo Grande
Arvin
Atascadero
Atherton
Atwater
Auburn
Avenal
Bakersfield
Barstow
Belmont
Belvedere
Benicia
Berkeley
Biggs
Blue Lake
Brentwood
Brisbane
Buellton
Burlingame
Calistoga
Campbell
Capitola
Carmel
Ceres
Chico
Chowchilla
Citrus Heights
Clayton
Clearlake
Cloverdale
Clovis
Coalinga
Colfax
Colma
Colusa
Concord
Corcoran
Corning
Corte Madera
Cotati
Cupertino
Daly City
Danville
Davis
Del Rey Oakes
Dinuba
Dixon
Dos Palos
Dublin
East Palo Alto
El Cerrito
Elk Grove
Emeryville
Escalon
Eureka
Fairfax
Fairfield
Ferndale
Firebaugh
Folsom
Fort Bragg
Fortuna
Foster City
Fowler
Fremont
Fresno
Galt
Gilroy
Gonzales
Grass Valley
Greenfield
Gridley
Grover Beach
Guadalupe
Gustine
Half Moon Bay
Hanford
Hayward
Healdsburg
Hercules
Hillsborough
Hollister
Hughson
Huron
Ione
Isleton
Jackson
Kerman
King City
Kingsburg
Lafayette
Lakeport
Larkspur
Lathrop
Lemoore
Lincoln
Live Oak
Livermore
Livingston
Lodi
Lompoc
Loomis
Los Altos
Los Altos Hills
Los Banos
Los Gatos
Madera
Manteca
Maricopa
Marina
Mariposa
Martinez
Marysville
McFarland
Mendota
Menlo Park
Merced
Mill Valley

Millbrae
Milpitas
Modesto
Monte Sereno
Monterey
Moraga
Morgan Hill
Morro Bay
Mountain View
Napa
Newark
Nevada City
Newman
Novato
Oakdale
Oakland
Oakley
Orange Cove
Orinda
Orland
Oroville
Pacific Grove
Pacifica
Palo Alto
Paradise
Parlier
Paso Robles
Patterson
Petaluma
Piedmont
Pinole
Pismo Beach
Pittsburg
Placerville
Pleasant Hill
Pleasanton
Plymouth
Point Arena
Portola
Portola Valley
Rancho Cordova
Red Bluff
Redding
Redwood City
Reedley
Richmond
Ridgecrest
Rio Dell
Rio Vista
Ripon
Riverbank
Rocklin
Rohnert Park
Roseville
Ross
Sacramento
Saint Helena
Salinas
San Anselmo
San Bruno
San Carlos
San Francisco
San Joaquin
San Jose
San Juan Bautista
San Leandro
San Luis Obispo
San Mateo
San Pablo
San Rafael
San Ramon
Sand City
Sanger
Santa Clara
Santa Cruz
Santa Maria
Santa Rosa
Saratoga
Sausalito
Scotts Valley
Seaside
Sebastopol
Selma
Shafter
Shasta Lake
Soledad
Solvang
Sonoma
Sonora
South San Francisco
Stockton
Suisun City
Sunnyvale
Sutter Creek
Taft
Tehama
Tiburon
Tracy
Trinidad
Turlock
Ukiah
Union City
Vacaville
Vallejo
Victorville
Walnut Creek
Wasco
Waterford
Watsonville
West Sacramento
Wheatland
Williams
Willits
Willows
Windsor
Winters
Woodland
Woodside
Yountville
Yuba City

VERIFICATION

I, the undersigned, say:

I am an officer of Pacific Gas and Electric Company, a corporation, and am authorized, pursuant to Rule 2.1 and Rule 1.11 of the Rules of Practice and Procedure of the Commission, to make this Verification for and on behalf of said Corporation, and I make this Verification for that reason. I have read the foregoing Application, and I am informed and believe that the matters therein concerning Pacific Gas and Electric Company are true.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct to the best of my knowledge.

Executed on 03/27/2025, at San Luis Obispo, California.

By: */s Maureen Zawalick*
Maureen Zawalick
Vice President, Business & Technical Services