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PACIFIC GAS AND ELECTRIC COMPANY

**DIABLO CANYON POWER PLANT 2027 COST RECOVERY
FORECAST TO SUPPORT OPERATIONS AS DIRECTED BY THE
STATE TO ENSURE ELECTRIC RELIABILITY
AND TO REDUCE GREENHOUSE GAS EMISSIONS FOR ALL
CALIFORNIANS**

UPDATE TO PREPARED TESTIMONY



PACIFIC GAS AND ELECTRIC COMPANY
DIABLO CANYON POWER PLANT 2027 COST RECOVERY FORECAST TO
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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **DIABLO CANYON POWER PLANT 2027 COST RECOVERY**
3 **FORECAST TO SUPPORT OPERATIONS AS DIRECTED BY THE**
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7 **UPDATE TO PREPARED TESTIMONY**

8 **A. Introduction**

9 In compliance with the June 16, 2026 Assigned Commissioner's Scoping
10 Memo and Ruling,¹ Pacific Gas and Electric Company (PG&E) submits to the
11 California Public Utilities Commission (CPUC or Commission) and the parties in
12 this proceeding its Update to Prepared Testimony (Fall Update). This Fall
13 Update reflects market conditions closer to the time when rates go into effect
14 and is consistent with the annual Diablo Canyon Power Plant (DCPP or Diablo
15 Canyon) Forecast process. PG&E's Fall Update incorporates updated market
16 and generation production information, updated allocation of the statewide 2027
17 Diablo Canyon Non-Bypassable Charge (DCNBC) to the investor-owned utilities
18 (IOU) based on updates to the California Energy Commission (CEC) load
19 forecast, and updates to the Energy Index and Resource Adequacy (RA) market
20 price benchmarks (MPB) issued by the CPUC's Energy Division on October 1,
21 2026.

22 The Fall Update results in a 2027 Diablo Canyon Extended Operations
23 (DCEO) net revenue requirement of \$934 million when compared to PG&E's
24 Prepared Testimony submittal in March, which forecast a net revenue
25 requirement of \$595 million. This results in an increase of \$339 million between
26 PG&E's initial prepared testimony and this 2027 Fall Update for the DCEO
27 Forecast as shown in the updated Table 1-3 below.

1 Assigned Commissioner's Scoping Memo and Ruling, issued June 16, 2026
 (Scoping Memo), p. 6.

**TABLE 1-3
2027 DCEO FORECAST NET REVENUE REQUIREMENT**

Line No.	Chapter Cross Reference	Diablo Canyon Extended Operations ^a 2027 Cost (\$1000s)			2027 March Prepared Testimony Total	Compare 2027 Fall Update to 2027 March Prepared Testimony
		Statewide	PG&E Specific	Total		
1	Total Forecast Costs	(A)	(B)	(C)	(D)	(C) - (D)
2	Operation and Maintenance Cost Forecast	780,456		780,456	779,713	742
3	Administrative and General	155,384		155,384	153,618	1,766
4	Management, Performance Fees, & Liquidated Damages	258,669	141,983	400,652	391,257	9,395
5	Resource Adequacy Substitution Capacity	14,297		14,297	16,451	(2,155)
6	Total Cost Forecast (excluding FF&U)	1,208,806	141,983	1,350,789	1,341,040	9,749
7	DCPP Market Revenues					
8	CAISO Market Revenues	(728,247)		(728,247)	(750,559)	22,312
9	Total Net Forecast Costs (excluding FF&U)	480,559	141,983	622,542	590,480	32,061
10	Balancing Account Amortization					
11	DCEOBA	296,923		296,923	(4,425)	301,347
12	Total Net Forecast Costs and DCEOBA amortization	777,482	141,983	919,464	586,056	333,408
13	RF&U (PG&E) + FF&U (SCE) and FF&U (SDG&E) ^b	12,404	1,932	14,335	8,947	5,389
14	DCEO Revenue Requirement for Ratesetting	789,885	143,914	933,799	595,002	338,797

Notes:

- (a) Amounts in 2027 dollars (\$s)
(b) SDG&E's FF&U revenue for its DCNBS will be collected in the its Distribution Charge.

One of the primary drivers for the change in the net revenue requirement is attributable to the 2026 end-of-year Diablo Canyon Extended Operations Balancing Account (DCEOBA) balance, which is forecast to be \$297 million undercollected due to lower recorded California Independent System Operator (CAISO) market revenues compared to the 2026 forecast CAISO market revenues.

In Section B, PG&E presents the updated forecasts and their associated drivers, including statutory fees, electric generation revenue forecast, RA substitution capacity cost forecast, and administrative and general (A&G) allocation update for 2027 to 2030. PG&E's forecast of operations and maintenance (O&M) cost presented in opening Prepared Testimony compared to this Fall update remains unchanged although there are changes to property tax and debt financing costs, which are discussed below.

Also in Section B, PG&E presents the updated RA and Energy Index MPBs, as defined by Decision (D.) 19-10-001, D.22-01-023, and D.25-06-049 for use in this proceeding.

In Section C, PG&E presents the updated revenue requirement, revenue requirement allocation among PG&E, Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E), and illustrative bill

1 impacts for each of the three utilities. In addition, the 2027 revenue requirement
2 is updated with an expected end-of-year DCEOBA balance for 2026, which is
3 composed of actual recorded costs for January 2026 through August 2026, with
4 a forecast of expected costs and revenues for September through December
5 2026.

6 In Section D, PG&E updates its Prepared Testimony Table 1-1 to reflect the
7 forecast updates contained in this Fall Update.

8 **B. Forecast Assumptions and Drivers**

9 **1. Updated MPBs**

10 The updated MPBs provided by the CPUC on October 1, 2026, are
11 provided below, along with a description of each.

TABLE A
COMPARISON OF FINAL MARKET PRICE BENCHMARKS

Line No.	Description	2025 Final Benchmarks (All IOUs)	2026 Final Benchmarks ^(a) (All IOUs)
1	Resource Adequacy Adder (\$kW-month)	\$11.21	\$10.11
2	Renewables Portfolio Standard (RPS) (\$/MWh)	63.26	30.88
3	GHG-free Adder (\$/MWh)	N/A	10.17 ^(b)

(a) D.25-06-049, Conclusion of Law (COL) 2 (“The Commission should adopt a single RA MPB based upon three-years’ transaction data for the forecast calculation and four-years’ transaction data for the final calculation.”)

(b) Per D.23-06-006 the IOUs have elected to allocate GHG free attributes. The GHG Adder is displayed for informational purposes only.

**TABLE B
COMPARISON OF FORECAST MARKET PRICE BENCHMARKS**

Line No.	Description	2026 Forecast Benchmarks	2027 Forecast Benchmarks ^(a)
	<u>Energy Index (\$/MWh)</u>		
1	On Peak – PG&E	\$50.20	\$44.22
2	Off Peak – PG&E	52.31	46.59
	<u>RA (\$/kW-month)</u>		
3	RA Adder	11.53	10.02
	<u>Renewables (\$/MWh)</u>		
4	RPS	62.45	12.69

(a) D.25-06-049, OP 2.

Energy Index

- Separate values for each IOU based on Platts average on-peak and off-peak market indices for North of Path-15 (NP-15) and South of Path-15.

RA Adder

- Single RA price for all IOUs based on all transacted RA categories, including local and flexible RA capacity.²

RPS Adder

- Single value for all IOUs based on index-plus Portfolio Content Category-1 RPS energy transactions.

2. 2027 Operational Revenue Requirement Excluding Statutory Fees

The 2027 Operational Revenue Requirement, excluding the statutory fees, includes the O&M cost, administrative and generation (A&G) expenses, debt financing cost, property and payroll taxes. The O&M portion of revenue requirement and payroll taxes remained unchanged from PG&E's Prepared Testimony while there were increases in A&G expenses, debt financing costs, and property taxes, as shown in the Table below:

² D.25-06-049, Conclusions of Law 2.

TABLE 4-1
OPERATIONAL REVENUE REQUIREMENT EXCLUDING STATUTORY FEES

Line No.	Expense	2027 March Filing	2027 Fall Update	Change
1	O&M	\$756,398,158	\$756,398,158	–
2	A&G	153,617,979	155,384,028	\$1,766,049
3	Debt Financing	(2,097,669)	(1,476,696)	620,973
4	Property Tax	754,281	875,655	121,374
5	Payroll Tax	24,658,580	24,658,580	–
6	Total	\$933,331,329	\$935,839,725	\$2,508,395

The drivers for the A&G increase include costs from PG&E's 2027 GRC Update, filed August 14, 2026, to reflect agreements reached with represented employees for the: (1) 2026-2028 GWI from 3.75 percent to 5.00 percent, (2) meals adjustments, and (3) labor equity adjustments. Property tax increased due to updated valuation on land and working cash increased as a result of updated forecasting inputs.

3. 2027 Fixed Payment Forecast Update

The 2027 Fixed Payment revenue forecast is updated to \$116.6 million from \$117.2 million. This forecast change is due to a decrease in the year-over-year Consumer Price Index (CPI) inflation forecast for the year 2027 using the S&P Q2 2026 Macro Financial Alternatives Forecast data series. PG&E's as-filed Fixed Payment forecast utilized the S&P Q4 2025 Macro Financial Alternatives Forecast data series. The Q2 2026 CPI inflation forecast for 2027 is 2.778 percent as compared to the Q4 2025 CPI inflation forecast for 2027 of 2.36 percent. Aside from the 2027 year-over-year forecast inflation change, the 2027 Fixed Payment revenue forecast methodology and inputs as described in PG&E's Prepared Testimony Chapter 5 have not changed.

4. 2027 Volumetric Performance Fees Revenue Forecast Update

The 2027 Volumetric Performance Fee (VPF) revenue forecast is updated to \$284 million from \$274.1 million. This forecast change is due to an increase in the cumulative escalation factor for the year 2027. More specifically, the change is the result of higher recorded expense non-O&M inflation for calendar year 2025 and forecast expense non-O&M inflation for calendar year 2026 for PG&E's CPUC-jurisdictional Functional Areas as

provided in the S&PQ2 2026 Power Planner data series as compared to the 2025 and 2026 expense non-O&M inflation forecasts for 2025 and 2026 for PG&E's CPUC-jurisdictional Functional Areas as provided in the S&P Q4 2025 Power Planner data series. The Q2 2026 cumulative inflation forecast for 2027 is 1.153 as compared to the Q4 2025 cumulative inflation forecast for 2027 of 1.194.

The updated 2027 VPF forecast to be recovered from all CPUC-jurisdiction load serving entities (LSE) subject to the DCNBC has increased to \$142 million from \$137 million.

Aside from the increase in forecast expense non-O&M inflation, the 2027 VPF revenue forecast methodology and inputs as described in PG&E's Prepared Testimony Chapter 5 have not changed.

5. DCPD Electric Generation Revenue Forecast Update

The DCPD generation revenue forecast was updated using the updated Commission-issued MPBs described in Section B.1 above. The update to the MPB used the NP-15 Platts on-peak and off-peak price curves published by the Commission on October 1, 2026, as part of its standard update process in the ERRR Forecast Proceeding.

The weighting of the on-peak and off-peak MPBs followed the same methodology described in PG&E's Prepared Testimony to form a single forward price for 2027. The updated forecast is shown in Table 6-1. Due to the reduction in the October 1, 2026, Energy Index MPB, the generation revenue is correspondingly reduced from \$751 million in the initial Prepared Testimony to \$728 million in the Fall Update.

**TABLE 6-1
FORECAST OF CAISO ENERGY MARKET REVENUES**

Line No.	Year	Total Generation (MWh)	CAISO Market Reference Price (\$/MWh)	Generation Revenues (Thousands of Dollars)
1	2027	18,288,481	39.82	728,247

6. RA Substitution Capacity Cost Forecast Update

The RA substitution capacity cost forecast was updated using the forecast 2027 PCIA RA MPB \$10.02/kW-month issued by the Commission on October 1, 2026. The updated cost forecast is shown in Table 4-1. Due to the decrease in the system RA MPB, the forecasted RA substitution capacity costs decreased from \$16.5 million shown in the Prepared Testimony to approximately \$14.3 million.

**TABLE 3-1
RA SUBSTITUTION CAPACITY FORECAST (2027)**

Line No.	Year	Total
1	2027	\$14,296,964

C. Fall Update

1. Net Revenue Requirement for Ratemaking

The purpose of this testimony is to consolidate PG&E's DCEO cost updates, described in Sections B.2, *Operational Revenue Requirement excluding Statutory Fees*, B.3, *Fixed Payment Forecast Update*; B.4, *2027 Volumetric Performance Fees Revenue Forecast Update*; B.5, *DCPP Electric Generation Revenue Forecast Update*; and B.6, *RA Substitution Cost Forecast* with the unchanged fixed management cost forecasts presented in PG&E's Prepared Testimony. This consolidated revenue requirement will constitute PG&E's Fall Update and allow PG&E to determine the net 2027 DCEO revenue requirement that will be allocated to the three large IOUs for rate setting. Updates to Tables 9-1 through 9-4 for this Fall Update are presented below.

Table 9-1 provides the updated Results of Operations revenue requirement for 2027 for DCPD operations and the authorized statutory fees, reflecting updates for the Fixed Management Fee and the VPF forecast described above.

**TABLE 9-1
TOTAL REVENUE REQUIREMENTS
(WHOLE DOLLARS)**

Line No.	Description	2027
1	Gross Total Revenue Requirements ^(a)	\$1,336,491,863

(a) Excludes RA Substitution Costs, CAISO Market Revenues, and Revenue or Franchise Fees and Uncollectibles (RF&U/FF&U)

Table 9-2 presents the updated RA Substitution Capacity Cost Forecast for 2027.

**TABLE 9-2
RA SUBSTITUTION CAPACITY COST FORECAST (2027)**

Line No.	Year	Unit 1	Unit 2	Total
1	2027	–	\$14,296,964	\$14,296,964

Table 9-3 presents the updated 2026 DCPD Generation Revenue Forecast, presented above.

**TABLE 9-3
CAISO MARKET REVENUES**

Line No.	Year	Generation Revenues
1	2027	\$ 728,247,314

A consolidated view of the updated revenue requirement for rate setting is presented in Table 9-4 below and includes all of the updated costs presented in Tables 9-1, 9-2, and 9-3. Specifically, Table 9-4 presents the consolidated costs on Line 12, and the CAISO generation revenue amounts on Line 14. Line 17 then presents a Subtotal for Net Costs which sums the

consolidated costs (Line 12), CAISO generation revenues (Line 14), and the 2026 DCEOBA balance (Line 16). Lastly, the Revenue Fee (or Franchise Fee) and Uncollectible (RF&U/FF&U) amounts on Line 19 are combined with Line 17 to present the 2027 DCEO Revenue Requirement for Ratesetting on Line 20.

**TABLE 9-4
NET REVENUE REQUIREMENT FORECAST
(THOUSANDS OF DOLLARS)**

Line No.	Chapter Cross Reference	Diablo Canyon Extended Operations ^a 2027 Cost (\$1000s)		
		Statewide (A)	PG&E Specific (B)	Total (C)
1	<u>Operational Revenue Requirement</u>			
2	Operation and Maintenance Cost Forecast	Chapters 2 & 4	780,456	780,456
3	Administrative and General	Chapter 4	155,384	155,384
4	Resource Adequacy Substitution Capacity	Chapter 3	14,297	14,297
5	Subtotal Operational Revenue Requirement	950,137		950,137
6	<u>Management, Performance Fees, and Liquidated Damages</u>			
7	Management Fee	Chapters 4 & 5	116,687	116,687
8	Liquidated Damages	Chapters 4 & 5	0	0
9	Volumetric Performance Fee	Chapters 4 & 5	141,983	141,983
10	PG&E Specific Volumetric Performance Fee	Chapters 4 & 5	141,983	141,983
11	Subtotal Statutory Fees	258,669	141,983	400,652
12	Total Cost Forecast (Line 5 + Line 11)	1,208,806	141,983	1,350,789
13	<u>Offsetting Market Revenues</u>			
14	CAISO Market Revenues	Chapter 6	(728,247)	(728,247)
15	<u>Balancing Account Amortization</u>			
16	DCEOBA	Chapter 8	296,923	296,923
17	Subtotal Net Cost (Line 12 + Line 14 + Line 16)	777,482	141,983	919,464
18				
19	RF&U (PG&E) + FF&U (SCE) and FF&U (SDG&E) ^b	Chapter 10	12,404	1,932
20	DCEO Revenue Requirement for Ratesetting	789,885	143,914	933,799

Notes:

(a) Amounts in 2027 dollars (\$s)

(b) SDG&E FF&U revenue for its DCNBC will be collected in Distribution Charge

2. End-of-Year DCEOBA Balance

a. Recorded 2026 Costs and Revenues

PG&E's recorded balance for the Diablo Canyon Operations Subaccount as of August 2026 is \$176 million. This includes the following activity for 2026 record period, year-to-date:

1 **1) Customer Revenue**

2 PG&E has accrued customer revenue based upon the GAAP
3 standard of accounting. Accordingly, PG&E currently estimates the
4 amount of revenues earned from customers. Accordingly, the
5 amounts are aligned with expectations from the monthly revenue
6 requirement seasonal trend for each IOU. Adjustments related to
7 any variance for final billed data from each IOU are included in the
8 forecast period for the final four months of 2026 and will be recorded
9 in the final quarter starting with the September accounting close
10 process as information becomes available.

11 **2) Authorized Costs**

12 Since January 2026, PG&E has incurred extended operations
13 costs, including: employee retention costs, projects costs, O&M
14 costs, and nuclear fuel straight line amortization to recover nuclear
15 fuel amortization and associated short term financing costs.
16 Additionally, PG&E expects to incur authorized RA Substitution
17 costs in October and November associated with the Unit 2 refueling
18 outage.

19 **3) Authorized Revenue Requirements**

20 PG&E has recorded the following authorized revenue
21 requirements through August 2026:

- 22 1) \$50 million for Liquidated Damages. This amount is set aside
23 and made available in the Liquidated Damages Subaccount for
24 future use.
25 2) \$76 million in fixed management fees for Unit 1 and Unit 2, both
26 of which have been in the extended operations period through
27 August 2026.

28 **4) Volumetric Performance Fees**

29 As of August 2026, PG&E recorded VPF as a percentage of
30 accrued customer revenues. These amounts are set aside in the
31 VPF Subaccount subject to use by expenses incurred by PG&E's
32 approved VPF spending plan. Specifically, PG&E set aside 83.5
33 percent of PG&E customer revenues, 45.9 percent of revenues from

1 SCE and 38.9 percent SDG&E customer revenues to the VPF
2 Subaccount.

3 PG&E's true-up (or true-down) to the earned VPF proceeds to
4 final generation amounts will be recorded prior to the end of the year
5 when final generation figures for the year are available.

6 **5) CAISO Net Revenue**

7 Finally, PG&E has recognized net CAISO revenues for Unit 1
8 and Unit 2 related to the period of extended operations for through
9 August 2026 of \$290 million.

10 **6) Balancing Account Interest**

11 PG&E has also recognized interest from the period of
12 January - August 2026. Interest is recorded in accordance with
13 electric Preliminary Statement Part JR, which indicates that the
14 three-month commercial paper rate in Federal Reserve Statistical
15 Release H.15 (or its successor) is used.

16 **b. Forecast 2026 Costs and Revenues for the Balance of 2026**

17 PG&E developed a forecast of authorized costs, billed customer
18 revenues, and CAISO Market revenues PG&E expects will accrue for
19 the months September through December, which when combined with
20 the recorded costs for the Diablo Canyon Operations Subaccount as of
21 August 2026, results in an undercollection of approximately \$297 million.
22 Highlights of the forecast for months September through December
23 include accrual forecasts in the following categories.

24 **1) Customer Revenue**

25 PG&E has developed an accrual forecast for expected customer
26 billed revenue in consultation with the other IOUs' revenue
27 accounting teams, which provided guidance on seasonal revenue
28 variations, and load forecast variance expected during the final
29 months of the year. Generally, the amounts are aligned with
30 expectations from the monthly seasonal revenue requirements for
31 each IOU. As noted above, adjustments related to any variance for
32 final billed data from each IOU is included in September –

December accrual and will be recorded in the final quarter as information becomes available.

2) Authorized Costs

For the forecast period September through December 2026, the forecast of O&M costs remains unchanged from the forecast submitted in PG&E's March testimony, which informs the monthly entries for balance of the year. Additionally, PG&E has included forecast entries for the RA substitution capacity costs it expects to incur in October and November using the October 1, 2026 RA MPB issued by the CPUC's Energy Division. There were no prior substitution cost entries to true-up using the October 1 MPB. Lastly, PG&E extrapolated the nuclear fuel straight line amortization recorded in previous months through to the months of September through December.

3) Authorized Revenue Requirements

For the months of September – December, PG&E has included entries that accrue the following revenue requirements up to the authorized level:

- 1) \$25 million for Liquidated Damages, which brings the total accrual for the 2026 record period to \$75 million which is consistent with the authorized amount. This amount is set aside and made available in the Liquidated Damages Subaccount for future use.
- 2) \$38 million for the fixed management fees which brings the total accrual for the 2026 record period to \$114 million and covers the extended operations of Unit 1 and Unit 2, which is in line with the authorized amount.

4) Volumetric Performance Fees

For the forecast period September to December 2026, PG&E developed accrual entries for the VPF based on the expected amount of monthly generation multiplied by the VPF rate, escalated to 2026 dollars, to arrive at a monthly accrual forecast for the balance of the year.

1 PG&E also developed a prior period accounting adjustment to
2 true-up the monthly accrual entries for VPFs that were posted
3 between January and August, which was based on a percentage of
4 accrued customer revenues, and was slightly overstated, when
5 compared to the calculated amounts based on the generation output
6 of DCPD multiplied by VPF rate stated in 2026 dollars. The true-up
7 entry aligns the accrual for the months January to August with the
8 original authorized forecast for these months.

9 PG&E's true-up (or true-down) to the earned VPF proceeds to
10 final generation amounts will be recorded prior to the end of the year
11 when final generation amounts are verified. PG&E's forecast does
12 include estimates of that true-up entry based on generation data that
13 is available.

14 **5) CAISO Net Revenue**

15 PG&E has accrued an estimate of net CAISO revenues for
16 Unit 1 and Unit 2 for the months September – December, using the
17 authorized energy prices for the balance of 2026. The total CAISO
18 market revenues for 2026 are forecast to be \$546 million, which is
19 \$297 million lower than the original authorized forecast of
20 \$842.7 million.

21 **c. DCNBC Operation Subaccount Entries Year to Date and Accrual for** 22 **the Balance of the Year**

23 Attachment A to this testimony presents PG&E's forecast for the
24 DCEOBA Operations Subaccount year-to-date and the accrual entries
25 for the balance for 2026.

26 **3. Diablo Canyon Revenue Allocation NBC**

27 The purpose of this section of testimony is to present an allocation of the
28 updated net revenue requirement for ratemaking to the three large IOUs,
29 PG&E, SCE, and SDG&E. Each IOU will then sponsor the DCNBC rate
30 allocations to customer classes in its service territory using its respective
31 12-Month Coincident Peak (12-CP) revenue allocation factors, as required in
32 D.23-12-036.

The first step to determine the DCNBC rates is to allocate the revenue requirement to the IOUs based on the CEC's 12-CP forecast for 2027. Table 10-1 presents the forecast data from the CEC and Table 10-2 presents the allocation factors derived from the CEC's 12-CP forecast.

TABLE 10-1
2027 CEC RA COINCIDENT PEAK LOAD FORECAST
(MW)

Line No.	Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Total
1	PGE	12,383	11,916	12,309	13,319	14,717	18,564	18,580	16,459	18,022	14,539	12,439	12,248	175,494
2	SCE	10,681	10,770	11,535	12,354	10,659	16,435	20,375	21,069	20,821	16,503	12,785	11,528	175,514
3	SDGE	2,702	2,710	2,612	2,592	2,421	2,979	3,513	3,991	4,162	3,585	3,038	2,802	37,107
4	Total	25,766	25,396	26,456	28,265	27,798	37,978	42,468	41,519	43,004	34,628	28,261	26,577	388,115

TABLE 10-2
12-CP LOAD ALLOCATION FACTORS
(MW)

IOU	Source	Duration	Term	MW	Percent
PG&E	2027 CEC 12-CP	1-Year	2026	175,494	45.22%
SCE	2027 CEC 12-CP	1-Year	2026	175,514	45.22%
SDG&E	2027 CEC 12-CP	1-Year	2026	37,107	9.56%
Total				388,115	100.00%

The consolidated DCPD extended operations net revenue requirement to be allocated to the IOUs is presented in Table 9-4 above. That revenue requirement is replicated in Table 10-3 below and totals \$933.8 million.

TABLE 10-3
2027 DIABLO CANYON EXTENDED OPERATIONS
NET REVENUE REQUIREMENT FORECAST
(THOUSANDS OF DOLLARS)

Line No.	Chapter Reference	Diablo Canyon Extended Operations ^a		
		2027 Cost (\$1000s)		
		Statewide	PG&E Specific	Total
		(A)	(B)	(C)
1	<u>Operational Revenue Requirement</u>			
2	Operation and Maintenance Cost Forecast	Chapters 2 & 4	780,456	780,456
3	Administrative and General	Chapter 4	155,384	155,384
4	Resource Adequacy Substitution Capacity	Chapter 3	14,297	14,297
5	Subtotal Operational Revenue Requirement	950,137		950,137
6	<u>Management, Performance Fees, and Liquidated Damages</u>			
7	Management Fee	Chapters 4 & 5	116,687	116,687
8	Liquidated Damages	Chapters 4 & 5	0	0
9	Volumetric Performance Fee	Chapters 4 & 5	141,983	141,983
10	PG&E Specific Volumetric Performance Fee	Chapters 4 & 5	141,983	141,983
11	Subtotal Statutory Fees	258,669	141,983	400,652
12	Total Cost Forecast (Line 5 + Line 11)	1,208,806	141,983	1,350,789
13	<u>Offsetting Market Revenues</u>			
14	CAISO Market Revenues	Chapter 6	(728,247)	(728,247)
15	<u>Balancing Account Amortization</u>			
16	DCEOBA	Chapter 8	296,923	296,923
17	Subtotal Net Cost (Line 12 + Line 14 + Line 16)	777,482	141,983	919,464
18	Uncollectibles, Franchise Fees, and SF Revenue Fee Factor ^c	Chapter 10		
19	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	12,404	14,335
20	DCEO Revenue Requirement for Ratesetting (Line 17 + Line 19) for PG&E and SCE (Line 17) for SDG&E		789,885	933,799
21	Distribution Revenue (SDG&E FF&U)			

Notes:

- (a) Amounts in 2027 dollars (\$s)
- (b) D.23-12-036, OP8 and OP11
- (c) SDG&E's FF&U revenues for its DCNBC will be collected in the Distribution Charge.

1 The revenue requirement in Table 10-3 is allocated to PG&E, SCE, and
2 SDG&E using the allocation factors from Table 10-2 of 45.22 percent,
3 45.22 percent, and 9.56 percent, respectively, and these allocated revenue
4 requirements are shown in Table 10-4.

TABLE 10-4
2027 DIABLO CANYON EXTENDED OPERATIONS
ALLOCATED NET REVENUE REQUIREMENT
(THOUSANDS OF DOLLARS)

Line No.	Chapter Reference	12-Month Coincident Peak Allocation ^a 2027 Cost Allocation (\$1000s)			2027 Total
		45.22% Pacific Gas & Electric	45.22% Southern California Edison	9.56% San Diego Gas & Electric	
1	<u>Operational Revenue Requirement</u>	(D)	(E)	(F)	(G)
2	Operation and Maintenance Cost Forecast	Chapters 2 & 4	352,922	352,922	780,456
3	Administrative and General	Chapter 4	70,265	70,265	155,384
4	Resource Adequacy Substitution Capacity	Chapter 3	6,465	6,465	14,297
5	Subtotal Operational Revenue Requirement		429,652	429,652	950,137
6	<u>Management, Performance Fees, and Liquidated Damages</u>				
7	Management Fee	Chapters 4 & 5	52,766	52,766	116,687
8	Liquidated Damages	Chapters 4 & 5	0	0	0
9	Volumetric Performance Fee	Chapters 4 & 5	64,205	64,205	141,983
10	PG&E Specific Volumetric Performance Fee	Chapters 4 & 5	141,983		141,983
11	Subtotal Statutory Fees		258,953	116,970	400,652
12	Total Cost Forecast (Line 5 + Line 11)		688,605	546,622	1,350,789
13	<u>Offsetting Market Revenues</u>				
14	CAISO Market Revenues	Chapter 6	(329,313)	(329,313)	(728,247)
15	<u>Balancing Account Amortization</u>				
16	DCEOBA	Chapter 8	130,352	130,467	296,923
17	Subtotal Net Cost (Line 12 + Line 14 + Line 16)		489,643	347,776	919,464
18	Uncollectibles, Franchise Fees, and SF Revenue Fee Factor ^c	Chapter 10	1.3604%	1.2264%	4.1550%
19	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	6,661	4,265	3,409
20	DCEO Revenue Requirement for Ratesetting (Line 17 + Line 19) for PG&E and SCE (Line 17) for SDG&E		496,304	352,041	82,045
21	Distribution Revenue (SDG&E FF&U)			3,409	3,409

Notes:

- (a) Amounts in 2027 dollars (\$s)
- (b) D.23-12-036, OP8 and OP11
- (c) SDG&E's FF&U revenues for its DCNBC will be collected in the Distribution Charge.

1 Line 20 presented in Table 10-4 (“DCEO Revenue Requirement for
2 Ratesetting”) will be used to set rates for each IOU. PG&E’s net
3 revenue requirement is \$496.3 million and is higher than the net
4 revenue requirements allocated to SCE and SDG&E due to the
5 additional VPF customers in PG&E’s service territory are obligated to
6 pay pursuant to SB 846.³ SCE’s allocated net revenue requirement for
7 ratesetting is \$352.0 million and SDG&E’s allocated net revenue
8 requirement for ratesetting is \$82.0 million.⁴

9 **4. Diablo Canyon NBC**

10 **a. PG&E DCNBC Rates**

11 To develop illustrative DCNBC rates, PG&E allocates PG&E’s share
12 of the revenue requirement to its various customer classes using the
13 12-CP allocation factors and then divides the allocated revenues by the
14 currently effective sales forecast. In Table 10-5, below, PG&E has
15 provided illustrative DCNBC rates applicable to each customer class.

³ Public Utilities Code (Pub. Util. Code) § 712.8(f)(5).

⁴ Consistent with the rest of the components within SDG&E’s Public Purpose Program (PPP) rate component, the FF&U associated with the SDG&E DCNBC rate of \$3.4 million will be collected through its distribution rate component.

**TABLE 10-5
PG&E'S 2027 DCNBC RATE CALCULATION**

Line No.	Customer Class	12-CP Allocation Factor	Revenue Requirement (\$000)	Sales Forecast (MWh)	2027 DCNBC Rate (\$/kilowatt-hour (kWh))	Customer Months Forecast	2027 DCNBC Rate (\$/day)
		(a)	(b) = PG&E's Revenue Requirement * (a)	(c)	(d) = (b)/(c)	(e)	(f) = (b)*1,000/(e) *12/365.25
1	Residential	48.4%	\$240,120	26,537,268	\$0.00905	60,952,394	\$0.12943
2	Small Commercial	8.5%	\$42,286	7,313,566	\$0.00578	N/A	N/A
3	Medium and Large Commercial	22.7%	\$112,868	21,631,821	\$0.00522	N/A	N/A
4	Streetlights	0.3%	\$1,263	240,593	\$0.00525	N/A	N/A
5	Standby	0.6%	\$2,934	555,174	\$0.00529	N/A	N/A
6	Agriculture	6.4%	\$31,899	5,290,582	\$0.00603	N/A	N/A
7	Industrial	13.1%	\$64,935	15,573,048	\$0.00417	N/A	N/A

As a result of the DCPD extended operations revenue requirement allocated to PG&E of \$496.3 million, the system average bundled service rate would increase by approximately 1.0 percent to 32.9 cents per kWh when compared to the present system average bundled service rate of 32.6 cents per kWh, effective March 1, 2026. The system average rate for Direct Access (DA) and Community Choice Aggregation (CCA) customers, whose average rates exclude generation charges that are provided by third-party service providers, 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 23.6 cents per kWh, which was effective March 1, 2026. Table 10-6 presents illustrative rate impacts by customer class and illustrative bundled service residential customer bill impacts.⁵

**TABLE 10-6
PG&E'S ILLUSTRATIVE RATE IMPACTS BY CUSTOMER CLASS**

Line No.	Illustrative Total Rate Impacts								
	Customer Class	Bundled				Direct Access and Community Choice Aggregator			
		3/1/2026 Present	1/1/2027 Proposed	Rate Change	% Change	3/1/2026 Present	1/1/2027 Proposed	Rate Change	% Change
1	Residential	32.34	32.57	0.23	0.7%	28.16	28.52	0.36	1.3%
2	CARE	21.80	21.63	-0.17	-0.8%	12.88	12.71	-0.17	-1.3%
3	Non-CARE	39.25	39.74	0.48	1.2%	31.76	32.25	0.49	1.5%
4	Small Commercial	40.53	40.90	0.36	0.9%	32.44	32.81	0.37	1.1%
5	Medium Commercial	35.46	35.82	0.36	1.0%	26.08	26.44	0.36	1.4%
6	Large Commercial (B-19)	31.17	31.52	0.36	1.1%	21.44	21.80	0.36	1.7%
7	B-19 T	16.87	17.29	0.41	2.4%	14.02	14.39	0.37	2.6%
8	B-19 P	25.57	25.92	0.36	1.4%	17.88	18.24	0.36	2.0%
9	B-19 S	32.11	32.47	0.36	1.1%	21.76	22.11	0.36	1.6%
10	Streetlight	43.02	43.31	0.29	0.7%	32.35	32.63	0.29	0.9%
11	Standby	15.02	15.40	0.39	2.6%	15.67	16.06	0.39	2.5%
12	Agriculture	38.34	38.79	0.45	1.2%	27.21	27.67	0.46	1.7%
13	Industrial (B-20)	21.62	21.94	0.32	1.5%	13.72	14.04	0.32	2.4%
14	B-20 T	17.77	18.10	0.32	1.8%	8.65	8.97	0.32	3.7%
15	B-20 P	24.60	24.93	0.32	1.3%	15.98	16.30	0.32	2.0%
16	B-20 S	27.92	28.24	0.32	1.2%	18.21	18.54	0.32	1.8%
17	Average System Rate	32.60	32.91	0.314	1.0%	23.64	23.99	0.355	1.5%
Illustrative Residential Bundled Customer Bill Impacts									
		3/1/2026 Present	1/1/2027 Proposed	Bill Change	% Change				
18	Non-CARE (500 kWh)	\$197.51	\$199.94	2.43	1.2%				
19	CARE (500 kWh)	\$111.39	\$110.58	-0.81	-0.7%				

⁵ Bills were calculated using the applicable Base Services Charges: \$24.15 per month for Non-CARE customers and \$6.00 per month for CARE customers.

1 **b. SCE DCNBC Rates**

2 SCE's DCNBC revenue allocation has been updated in the Fall
3 Update to 45.22 percent. This 45.22 percent equates to
4 \$352.041 million in forecasted revenue (including FF&U)⁶ for 2027 that
5 is to be recovered in electric rates effective January 1, 2027. Pursuant
6 to D.23-12-036,⁷ SCE will continue to allocate its total revenue
7 requirement within its service area based on SCE's then-current 12-CP
8 allocation factors that are used as part of SCE's existing CAM.

9 To allocate the costs to the various customer classes, SCE will
10 utilize the current approved 12-CP allocation factors that are used for
11 the CAM, which can be found in SCE's most recently approved
12 Transmission Owner (TO) rate case and is shown in Table 10-7 below.⁸
13 Should a new TO Rate Filing with revised 12-CP allocator factors be
14 adopted prior to the January 1, 2027 effective date, SCE will update
15 these allocations to align with the latest approved 12-CP allocation
16 factors upon implementation.

6 In accordance with D.25-09-030, which approved SCE's 2025 GRC, and Advice 5663-E, SCE has updated its FF&U to 1.2264 percent.

7 *Ibid.*, p. 74.

8 See SCE's Formula Transmission Rate Filings; hyperlink at:
<https://www.sce.com/regulatory/open-access-information/formula-transmission-rate>.

TABLE 10-7
SCE'S 12-CP ALLOCATION FACTORS

Line No.	Customer Class	12-CP Allocation Factor ^(a)
1	Domestic	46.02%
2	TOU-GS-1	6.89%
3	TC-1	0.04%
4	TOU-GS-2	15.02%
5	TOU-GS-3	8.00%
6	TOU-8-SEC	7.46%
7	TOU-8-PRI	5.66%
8	TOU-8-SUB	6.54%
9	TOU-8-Standby-SEC	0.08%
10	TOU-8-Standby-PRI	0.18%
11	TOU-8-Standby-SUB	0.57%
12	TOU-PA-2	1.65%
13	TOU-PA-3	1.54%
14	Street Lighting	0.35%

(a) The 12-CP Allocators for the TOU-8-nonStandby and TOU-8-Standby Customer Class have been adjusted from the original allocator values. These adjustments were made to account for the shift of supplemental load from the TOUT-8-nonStandby Customer Class to the TOU-8-Standby Customer Class. Adjustments were made based on the respective system sales and voltages (SEC, PRO, SUB). No other allocators have been adjusted.

1 To develop the DCNBC rate, SCE used the current effective sales
2 forecast adopted in SCE's 2026 ERRRA Forecast (A.25-05-008),⁹ which
3 is shown in Table 12-8 below. If SCE's 2027 ERRRA Forecast
4 Application (A.26-05-006) is adopted and effective by January 1, 2027,
5 the same time that the DCNBC becomes effective, SCE will update the
6 DCNBC to reflect the 2027 sales forecast from its 2027 ERRRA Forecast
7 Application.

⁹ See D.24-12-039, which approved SCE's 2025 ERRRA Forecast Application.

**TABLE 10-8
SCE'S 2027 DCNBC RATE CALCULATION**

Line No.	Customer Class	12-CP Allocation Factor	Revenue Requirement (\$000)	Sales Forecast (MWh)	2026 DCNBC Rate (\$/kWh)
		(a)	(b) = SCE's Revenue Requirement * (a)	(c)	(d) = (b) / (c)
1	Domestic	46.02%	\$162,007	27,340,000	\$0.00593
2	TOU-GS-1	6.89%	\$24,253	5,845,431	\$0.00415
3	TC-1	0.04%	\$157	53,036	\$0.00296
4	TOU-GS-2	15.02%	\$52,863	13,090,151	\$0.00404
5	TOU-GS-3	8.00%	\$28,151	7,428,852	\$0.00379
6	TOU-8-SEC	7.46%	\$26,278	7,614,658	\$0.00345
7	TOU-8-PRI	5.66%	\$19,925	6,281,060	\$0.00317
8	TOU-8-SUB	6.54%	\$23,041	7,865,863	\$0.00293
9	TOU-8-Standby-SEC	0.08%	\$268	77,571	\$0.00345
10	TOU-8-Standby-PRI	0.18%	\$649	204,548	\$0.00317
11	TOU-8-Standby-SUB	0.57%	\$1,994	680,763	\$0.00293
12	TOU-PA-2	1.65%	\$5,823	1,692,432	\$0.00344
13	TOU-PA-3	1.54%	\$5,416	1,846,648	\$0.00293
14	Street Lighting	0.35%	\$1,217	424,297	\$0.00287

**TABLE 10-9
SCE'S ESTIMATED RATES
BUNDLED AVERAGE RATES (¢/kWh)**

Line No.	Customer Group	Current Rates	Proposed Change	Proposed Rates	Percentage Change
1	Residential	34.5	0.32	34.9	0.9%
2	Lighting – Small and Medium Power	29.7	0.29	30.0	1.0%
3	Large Power	20.2	0.22	20.5	1.1%
4	Agricultural and Pumping	23.8	0.24	24.1	1.0%
5	Street and Area Lighting	36.7	0.37	37.1	1.0%
6	Standby	15.0	0.05	15.0	0.3%
7	Total	30.2	0.22	29.9	1.0%

TABLE 10-10
SCE'S ESTIMATED BILL IMPACTS
RESIDENTIAL (\$/MONTH)

Line No	Description	Current	Proposed Change	Proposed	Percent Change
1	Non-CARE Residential Bill	\$188.64	\$1.81	\$190.45	1.0%
2	CARE Residential Bill	\$111.25	\$1.17	\$112.42	1.0%

c. SDG&E DCNBC Rates

1) Background

Pursuant to D.23-12-036, the Commission conditionally approved extended operations at DCPD in response to SB 846 and approved a non-bypassable charge (NBC) to be included in Public Purpose Program (PPP) rates to support the extended operations of DCPD.¹⁰ SDG&E's portion of the DCNBC will be collected from customers within SDG&E's service territory for remittance to PG&E, the operator of DCPD Units 1 and 2, as required by D.23-12-036.¹¹

Pursuant to Rule 3.2, SDG&E will collaborate with PG&E, SCE, Bear Valley Electric Service, Inc., Liberty Utilities, PacifiCorp d/b/a Pacific Power, and the Commission's Public Advisor's Office to ensure all participating utilities comply with requirements that are a result of PG&E's DCPD Extended Operations Forecast application.

2) 2027 DCNBC Rate

As discussed in Section C.3, SDG&E's updated cost allocation is 9.56 percent based on collective 12-CP among PG&E, SCE, and SDG&E (the Joint IOUs). This equates to \$82.0 million¹² in 2027 revenue requirement, as shown in Table 10-14, to be recovered in SDG&E's electric rates effective January 1, 2027. This is an increase of \$48.0 million compared to current. As discussed further below, SDG&E allocates its 2027 revenue requirements to its customer classes and then utilizes its most recent sales forecast to

¹⁰ D.23-12-036, OP 1 and OP 14.

¹¹ *Ibid.*, Finding of Fact (FOF) 14 and COL 47.

¹² Excludes FF&U.

1 develop its 2027 DCNBC rates to be charged by customer class.
2 This calculation and resulting rates can be found in Table 10-11
3 below.¹³

4 To allocate costs to its customer classes, SDG&E utilizes the
5 current 12-CP demand that can be found in Statement BL in Docket
6 Number ER26-632-000 of SDG&E's TO 6 Cycle 2 Filing.¹⁴ SDG&E
7 will update these allocations upon implementation if a new 12-CP
8 forecast is approved.

9 To develop the 2027 DCNBC rate, SDG&E utilizes the current
10 effective sales forecast, which was originally adopted in SDG&E's
11 2026 ERRRA Forecast & Sales proceeding (A.25-05-012)¹⁵ and later
12 updated through implementation of the 2024 General Rate Case
13 (GRC) Phase 2 on April 1, 2026.¹⁶ Upon implementation, SDG&E
14 will update this forecast to use current adopted sales forecast at that
15 time.¹⁷

¹³ Table 10-11 includes the Medium and Large Commercial & Industrial customer class as a single class. On September 30, 2026, SDG&E filed Docket No. ER26-3896-000 which splits this class into Medium Commercial and Large Commercial & Industrial customer classes effective January 1, 2027. This includes the calculation of SDG&E's 12 CP Allocation Factor. SDG&E will illustrate this change to rates in future proceedings when applicable to current rates.

¹⁴ Docket No. ER26-632-000: TO6 Cycle 2 Annual Informational Filing Statement BL, p. BL-2.

¹⁵ D.25 12 008 was implemented in rates effective January 1, 2026.

¹⁶ D.25-09-006 approved, among other changes, the establishment of a new "Medium Commercial" customer class which included the recategorization of the Small Commercial Schedule TOU-M into the newly created customer class.

¹⁷ For example, SDG&E filed its 2027 sales forecast in its 2027 ERRRA/Sales Forecast application A.26-05-009 on May 15, 2026. If the new sales forecast is adopted and effective January 2027, at the same time this DCP rate becomes effective, SDG&E will update the DCP rate to utilize the current effective 2027 sales forecast.

**TABLE 10-11
SDG&E'S DCNBC RATE CALCULATION**

Line No.	Customer Class	12-CP Allocation Factor (SDG&E's TO6 C2)	Revenue Requirement (RRQ) (\$000)	Sales Forecast 2026 ERRRA Filing ^(a) (GWh)	2027 DCNBC Rate (\$/kWh)
		(a)	(b) = SDG&E's RRQ * (a)	(c)	(d) = (b)/(c)/1000
1	Residential	44.5%	\$36,487.79	7,312	\$0.00499
2	Small Commercial	11.5%	\$9,446.91	1,813	\$0.00521
3	Medium and Large Commercial & Industrial	42.6%	\$34,964.92	9,865	\$0.00354
4	Agriculture	1.1%	\$898.41	404	\$0.00222
5	Streetlight	0.3%	\$247.23	82	\$0.00301
6	System Average	100%	\$82,045.25	19,476	\$0.00421

(a) SDG&E's sales forecast is utilizing System Delivered sales since PPP is a non-bypassable charge.

1 The DCNBC rate will be added to components of the PPP rate
2 for customer billing.¹⁸ Any updates to allocation factors or sales
3 forecast will be included in SDG&E's annual electric consolidated
4 advice letter filing process.¹⁹

5 The 2027 DCNBC results in an increase to electric total system
6 average rate of 0.257 cents/kwh,²⁰ which is a 1.2 percent increase
7 to delivery rates or 0.7 percent increase to bundled (delivery plus
8 commodity) rates. Table 10-12 below presents a table summarizing
9 the rate impacts by customer class.²¹

¹⁸ D.23-12-036, pp. 138-139, OP 14.

¹⁹ The DCNBC is currently fully volumetric (\$/kWh) in 2026 rates. However, the residential DCNBC is eligible to be part of the PPP portion of the Residential Fixed Charge per D.24-05-028 should allocation be necessary.

²⁰ System Average Rate Includes FF&U.

²¹ On March 2, 2026, SDG&E filed AL 4791-E which splits the Medium and Large Commercial & Industrial customer class into Medium Commercial and Large Commercial & Industrial customer classes Effective April 1, 2026. SDG&E now illustrates this change to current rates in Table 10-12.

TABLE 10-12
SDG&E'S ILLUSTRATIVE RATE IMPACT BY CUSTOMER CLASS

Rate Impacts (Unbundled) ^(a)					
Line No.	Customer Class	Current Elec. Delivery Class Average Rates	Proposed Elec. Delivery Class Average Rates	Total Rate Increase (¢/kWh)	Percentage Average Rate Increase (%)
		Effective 8/1/26 (¢/kWh)	1/1/27 DCPD NBC (¢/kWh)		
1	Residential	25.0	25.4	0.3	1.2%
2	Small Comm.	23.8	24.2	0.3	1.3%
3	Medium Commercial	19.6	19.8	0.2	1.1%
4	Large C&I	18.2	18.5	0.2	1.2%
5	Agriculture	13.8	14.0	0.1	1.0%
6	Lighting	14.0	14.2	0.2	1.3%
7	System Total	21.1	21.3	0.3	1.2%

(a) "Unbundled" customers receive electric generation from an Energy Service Provider (ESP) that is not SDG&E.

Rate Impacts (Bundled) ^(a)					
Line No.	Customer Class	Current Total Class Average Rates	Proposed Total Class Average Rates	Total Rate Increase (¢/kWh)	Percentage Average Rate Increase (%)
		Effective 8/1/26 (¢/kWh)	1/1/27 DCPD NBC (¢/kWh)		
1	Residential	43.1	43.4	0.3	0.7%
2	Small Comm.	40.0	40.3	0.3	0.8%
3	Medium Commercial	38.4	38.6	0.2	0.6%
4	Large C&I	38.0	38.2	0.2	0.6%
5	Agriculture	26.2	26.3	0.1	0.5%
6	Lighting	26.4	26.6	0.2	0.7%
7	System Total	39.3	39.5	0.3	0.7%

(a) "Bundled" customers receive electric generation from SDG&E.

- 1 Table 10-13 below shows illustrative bill impacts for a typical
- 2 residential customer.

TABLE 10-13
SDG&E'S ILLUSTRATIVE BILL IMPACT FOR A TYPICAL RESIDENTIAL CUSTOMER

Bill Impacts ^(a)					
Line No.	Customer Class	Current	Proposed	Total Rate Increase (\$/month)	Percentage Average Rate Increase (%)
		Effective 8/1/26 (\$/month)	1/1/27 DCPP NBC (\$/month)		
1	Unbundled, 2021V ^(a)	\$122.98	\$124.12	\$1.15	0.9%
2	Bundled ^(b)	\$182.59	\$183.73	\$1.15	0.6%

(a) "Unbundled" customers receive electric generation from an ESP that is not SDG&E.

(b) "Bundled" customers receive electric generation from SDG&E. May not sum due to rounding.

D. Table 1-1 Period of Extended Operations Cost Update

Table 1-1 below presents the updated DCPP extended operations period total costs. Updates include: (1) the Fixed Payment forecast change on line 6 due to the CPI-U year-over-year escalation rate increase for 2027 through 2030; (2) the forecast change for the 2027 VPF revenues on line 7 due to the increase in expense escalation and for 2027 through 2030, (3) updates to from the 2027 GRC filing for 2027 through 2030 on line 9, (4) the 2027 through 2030 forecast DCPP Generation Market Revenues due to the updated per megawatt-hour price change, (5) the 2027 through 2030 forecast RA substitution capacity cost changes on line 15 due to the lower PCIA RA MPB, (6) the 2027 through 2030 RA Capacity Benefit forecast change on line 16 due to the decrease in the PCIA system RA MPB, and (7) the total changes on lines 19, 20, and 21 accounting for all of the changes above. Each of these line-item updates for the 2026 recorded period are discussed in detail in Section C above.

Additionally, the FF&U values on line 11 have been updated to reflect the impacts of the aforementioned forecast updates.

TABLE 1
2023-2030 EXTENDED OPERATIONS COSTS, REVENUE CREDITS, AND SOCIETAL BENEFITS
(MILLIONS OF DOLLARS)

Line No.	Forecast Item	2023A	2024A	2025A	2026A	2027F	2028F	2029F	2030F
1	DCPP Direct Costs (Ch. 2)								
2	Expense O&M and Projects (Excludes Nuclear Fuel Procurement)	\$ 17,025	\$ 63,586	\$ 417,724	\$ 563,935	637,945	629,541	439,444	371,050
3	Nuclear Fuel Expense Amortization (Ch. 2)	\$ -	\$ -	\$ 134,002	\$ 135,734	\$ 118,454	\$ 118,454	\$ 118,454	\$ 118,454
4	Spent Nuclear Fuel Management Department of Energy (DOE) Litigation Balancing Account Proceeds	\$ -	\$ -	\$ -	(\$12,587)	(\$11,440)	(\$10,514)	(\$23,462)	(\$3,430)
5	Statutory Fees (Ch. 5)								
6	Fixed Payment	\$ -	\$ 7,869	\$ 66,479	\$ 113,997	\$ 116,687	\$ 119,569	\$ 116,833	\$ 56,956
7	Volumetric Performance Fee	\$ -	\$ 19,467	\$ 147,638	\$ 266,567	\$ 283,965	\$ 274,325	\$ 286,018	\$ 117,724
8	Results of Operations Items (Ch. 4)								
9	A&G Allocation	\$ -	\$ -	\$ -	\$ -	\$ 155,384	\$ 159,472	\$ 113,921	\$ 52,796
10	Taxes	\$ 1,928	\$ 5,211	\$ 17,573	\$ 23,659	\$ 25,534	\$ 27,611	\$ 21,993	\$ 20,029
11	Revenue Fees and Uncollectibles	\$ 271	\$ 787	\$ 8,823	\$ 7,562	\$ 9,509	\$ 8,683	\$ 3,572	\$ 1,498
12	Debt Financing Costs (Excluding Nuclear Fuel Debt Financing)	\$ -	\$ 173	\$ 2,925	\$ 2,918	\$ (1,477)	\$ (2,194)	\$ (1,971)	\$ (1,542)
13	Nuclear Generation Related Benefits and Costs								
14	DCPP Generation Market Revenues (Ch. 6)	\$ -	\$ (80,043,587)	\$ (544,204,773)	\$ (842,676)	\$ (728,247)	\$ (785,890)	\$ (848,522)	\$ (346,691)
Line No.	Forecast Item	2023	2024	2025	2026	2027	2028	2029	2030
15	RA Substitution (Ch. 3)	\$ -	\$ 14,968	\$ 50,388	\$ 26,288	\$ 14,297	\$ 28,594	\$ -	\$ 14,297
16	RA Capacity Benefit (Ch. 1)	\$ -	\$ (59,873)	\$ (204,470)	\$ (315,461)	\$ (274,147)	\$ (274,147)	\$ (251,302)	\$ (114,228)
17	Other Costs								
18	Liquidated Damages Subaccount (Ch. 5)	\$ -	\$ 25,000	\$ 200,000	\$ 75,000	\$ -	\$ -	\$ -	\$ (300,000)
19	Total Extended Operations Gross Revenue Requirement	\$ 19,224	\$ 137,061	\$ 1,045,553	\$ 1,203,071	\$ 1,344,434	\$ 1,353,541	\$ 1,074,802	\$ 447,831
20	Total Extended Operations Net Revenue Requirement	\$ 19,224	\$ 57,018	\$ 501,348	\$ 360,396	\$ 616,186	\$ 567,651	\$ 226,279	\$ 101,140
21	Total Annual Cost Including RA Capacity Benefit	\$ 19,224	\$ (2,855)	\$ 296,877	\$ 44,935	\$ 342,039	\$ 293,504	\$ (25,022)	\$ (13,088)

A refers to amounts adopted in prior decisions. These amounts will be replaced with final recorded costs upon Commission approval of each annual true up advice letter.

****F**** refers to amounts forecast in this application.

***** Totals may not sum precisely due to rounding.

***** Rows 19 reflects the DCEGBA credit of \$4,425 million for forecast year 2027. This credit cascades into rows 20 and 21 for forecast year 2027.

1 **E. Conclusion**

2 PG&E appreciates the opportunity to submit the Fall Update and
3 recommends the Commission adopt the proposals herein.

PACIFIC GAS AND ELECTRIC COMPANY
ATTACHMENT A
2026 DCEOBA END OF YEAR BALANCE
AND FORECAST

AtchA-2