Application: 24-03-018
Exhibit No. EPUC-1

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of the Pacific Gas & Electric Company (U39 E) 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.	**Application 24-03-018**

Direct Testimony and Schedules of

Michael P. Gorman

On behalf of

Energy Producers & Users Coalition ("EPUC")

July 29, 2024

BRUBAKER & ASSOCIATES, INC.
Project 11688

Table of Contents to the Direct Testimony of Michael P. Gorman

TABLES

SCHEDULES

APPENDIX

INTRODUCTION AND RECOMMENDATIONS

Q1 PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q2 WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Managing Principal of the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q3 PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is provided in Appendix A to my testimony.

Q4 ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Energy Producers & Users Coalition ("EPUC").

Q5 WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A My testimony addresses Pacific Gas & Electric Company's ("PG&E" or "Company") application ("A.") 24-03-018 (the "Application") requesting California Public Utilities Commission ("Commission") review and approval of forecast costs and related proposals related to life extension of Diablo Canyon Power Plant ("Diablo Canyon" or "DC") over 2023-2025 (the "Record Period").

Q6 PLEASE OUTLINE YOUR RECOMMENDATIONS IN THIS PROCEEDING.

A First, I address PG&E's proposal to modify the 12-month coincident peak demand (12-CP) allocation of Diablo Canyon's resource adequacy ("RA") capacity and greenhouse gas ("GHG") benefits approved in Decision ("D.") 23-12-036. Next, I address PG&E's forecast revenue requirement used to determine the Diablo Canyon Non-Bypassable Charge ("DCNBC"), and make certain recommendations to ensure that the DCNBC reflects a reasonable forecast of costs over the Record Period, and results in just and reasonable charges to customers. Finally, I use a revised revenue requirement based on my recommendations to calculate alternate DCNBC rates that should be adopted.

My recommended adjustments to PG&E's proposals are summarized as follows:

1. The Commission should reject PG&E's proposal for a modified 12-CP allocation of Diablo Canyon's RA and GHG benefits. Instead, the Commission should adhere to its precedent and require PG&E to adhere to the 12-CP allocation methodology adopted in D.23-12-036.

2. The Commission should base the 2025 DCNBC on revenues and billing units applicable to 2025 operations, and reject PG&E's proposal to include multi-year costs developed over single-year billing units.

3. The Commission should reject PG&E's proposal for application of a gross-up and an escalation factor to the Management Fee paid to PG&E for life extension of Diablo Canyon.

4. The Commission should require PG&E to limit collection of costs to cover Diablo Canyon liquidated damages to the periods in which the current DCNBC licenses are in effect.

5. The Commission should require PG&E to adjust the forecasted 2025 California Independent System Operator ("CAISO") market energy price revenue used to reduce the 2025 Diablo Canyon life extension

revenue requirement using unadjusted forward price projections for the CAISO North of Path 15 (“NP15”) zone in 2025. Specifically, the Commission should require PG&E to increase the $68.57/MWh price used in its calculation to $73.40/MWh to reflect 2025 forward price data.

PG&E’S PROPOSED MODIFICATION TO THE DC BENEFIT ALLOCATION METHODOLOGY APPROVED IN D.23-12-036 SHOULD BE REJECTED

Q7 DID PG&E RECOMMEND ALLOCATION OF DIABLO CANYON RA CAPACITY AND GHG ENERGY ATTRIBUTE BENEFITS ACROSS LOAD-SERVING ENTITIES?

A Yes. In D.23-12-036, the Commission directed the allocation of Diablo Canyon’s extended operations costs and benefits to Pacific Gas & Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric Company (SDG&E) (collectively, the “Utilities” or “IOUs”). The allocation must be based on each IOU’s load share of 12-CP, and then allocated to load-serving entities (LSEs) within each IOU’s service territory based on a process that mirrors the CAM.[1] PG&E does not take issue with the 12-CP allocation of Diablo Canyon life extension costs. However, with respect to allocation of RA capacity and GHG benefits, PG&E inappropriately seeks to modify the authorized methodology to shift the balance of benefits in PG&E’s favor, citing PG&E’s larger cost responsibility for DC life extension costs.[2]

---

[1] D.23-12-036, Conclusions of Law (CoL) 28-30, 34-35, 38, and 42; Ordering Paragraphs (Ops) 7, 9, and 10.
[2] PG&E Chapter 2 at pp. 2-20 through 2-23.

Specifically, pursuant to Pub. Util. Code Section 712.8(f)(8), PG&E customers are subject to an additional $6.50/MWh volumetric performance fee that is not charged to SCE and SDG&E service area customers.[3] In light of this additional fee, PG&E proposes to modify the allocation methodologies adopted in D.23-12-036 such that a greater proportion of Diablo Canyon's RA and GHG attributes flow to PG&E. To reflect the additional volumetric performance fee, PG&E proposes to allocate Diablo Canyon's 2,280 MW RA benefits using a total net cost allocator, as presented in Chapter 2 of PG&E's Prepared Testimony on page 2-22, Table 2-12.

TABLE 1

COPY OF TABLE 2-12
ESTIMATED RESOURCE ADEQUACY CAPACITY ATTRIBUTE ALLOCATION AMOUNTS

Line No.	Utility Service Area	(A) Allocation Amount *Before* the Additional \$6.50/MWh Cost Burden (MW)	(B) Allocation Amount *After* the Additional \$6.50/MWh Cost Burden (MW)
1	PG&E	1,026	1,108
2	SCE	1,019	953
3	SDG&E	235	219

Q8 IS PG&E'S PROPOSED MODIFIED ALLOCATOR FOR DIABLO CANYON RESOURCE CAPACITY AND GHG SOCIETAL BENEFITS REASONABLE?

[3] PG&E Chapter 2 at p. 2-21.

A No. The Commission has already considered and developed an appropriate allocation for Diablo Canyon's RA and GHG benefits among the Utilities. In D.23-12-036, the Commission concluded:

> It is reasonable, and consistent with SB 846, to allocate the RA benefits of DCPP extended operations to each large electrical corporation service area on the basis of 12-month coincident peak demand.[4]
>
> . . .
>
> It is reasonable to allocate RA benefits to LSEs, including SCE and SDG&E but not including PG&E, as a load decrement using a process that mirrors the CAM process, once RA benefits have been allocated to each large electrical corporation service area on the basis of 12-month coincident peak demand.[5]
>
> . . .
>
> LSEs that pay for extended operations at DCPP should be allowed to access the benefits of extended operations, including the GHG attributes of DCPP.[6]
>
> . . .
>
> [T]he resource adequacy benefits (RA) associated with Diablo Canyon Nuclear Power Plant extended operations shall be allocated among Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) service areas on the basis of 12-month coincident peak load in each of PG&E's annual Diablo Canyon Nuclear Power Plant Extended Operations Cost Forecast applications.[7]

The Commission held that "ensuring system reliability is a key legislative rationale for the billions of ratepayer dollars that may be spent to keep DCCP [Diablo Canyon] operating", deeming a 12-month coincident peak load cost

---

[4] D.23-12-036 at CoL 35.
[5] D.23-12-036 at CoL 38.
[6] D.23-12-036 at CoL 41.
[7] D.23-12-036 at OP 9.

allocation fair and equitable.[8] In deliberating over the allocation of both RA and GHG benefits, the Commission was similarly very clear:

> It is fair and reasonable to allocate RA benefits to the large electrical corporations in the same manner that eligible costs for extended operations at DCPP are allocated to them (*i.e.,* by each large electrical corporation's share of 12-month coincident peak demand).[9]
>
> . . .
>
> The RA benefits of DCPP extended operations shall be allocated to LSEs, including SCE and SDG&E but not PG&E, as a load decrement using a process that mirrors the CAM process, once RA benefits have been allocated to each electrical corporation on the basis of 12-month coincident peak demand.[10]
>
> . . .
>
> Ultimately, those LSEs that pay for extended operations at DCPP should be allowed to access the benefits of extended operations, including the GHG attributes of DCPP.[11]

The Commission repeated its determination that:

> a process mirroring the CAM process should be used to allocate the DCPP extended operations costs and benefits within the service territories of PG&E, SCE and SDG&E, and that each large electrical corporation's share of 12-month peak coincident demand should be used to allocate the costs and benefits among the large electrical corporations.[12]

PG&E's proposed allocation methodology does not comply with the adopted allocation methodology and is an impermissible collateral attack on D.23-12-036 and should be denied. The Commission should adhere to its

---

[8] D.23-12-036 at pp. 73-74.
[9] D.23-12-036 at p. 81; see also D.23-12-036 at p. 83 ("the allocation of RA attributes and their benefits to LSEs is grounded in the equity of affording benefits of extended operations at DCPP to those LSEs that pay for the costs of extended operations").
[10] D.23-12-036 at p. 85.
[11] D.23-12-036 at p. 90.
[12] D.23-12-036 at p. 103.

precedent and require PG&E to allocate the Diablo Canyon RA capacity benefits and GHG benefits in proportion to the 12-CP allocation methodology approved in D.23-12-036.

DC LIFE EXTENSION NET REVENUE REQUIREMENT

Q9 PLEASE OUTLINE PG&E'S DEVELOPMENT OF A NET REVENUE REQUIREMENT AND DCNBC RATE APPLICABLE TO PG&E, SCE AND SDG&E.

A Chapter 1 of PG&E's prepared testimony presents the Company's proposed revenue requirement for extending the life of Diablo Canyon for 2023-2025. Table 1-2 on page 1-7 of Chapter 1, reproduced as **Table 2**, below, summarizes the Company's proposed revenue requirements for setting its proposed 2025 DCNBC rates.

TABLE 2

COPY OF PG&E TABLE 1-2
DETAILED TOTAL NET REVENUE REQUIREMENT FOR RATESETTING

Line No.		Chapter Cross Reference	Diablo Canyon Extended Operations 2023-2025 Cost ($1000s)[a]		
			Statewide	PG&E	Total
1	Operational Revenue Requirement		(A)	(B)	(C)
2	Operation and Maintenance Cost Forecast	Chapters 3 & 6	633,164		633,164
3	Resource Adequacy Substitution Capacity	Chapter 4	76,444		76,444
4	SMJUs Revenue Credit and RA Reimbursement[b]		0		
5	**Subtotal Operational Revenue Requirement**		**709,608**		**709,608**
6					
7	Management, Performance Fees, and Liquidated Damages				
8	Management Fee	Chapters 6 & 7	112,711		112,711
9	Liquidated Damages	Chapters 6 & 7	225,000		225,000
10	Volumetric Performance Fee	Chapters 6 & 7	79,805		79,805
11	***PG&E Specific*** Volumetric Performance Fee	Chapters 6 & 7		79,805	79,805
12	**Subtotal Statutory Fees**		**417,517**	**79,805**	**497,322**
13	**Total Cost Forecast (Line 5 + Line 12)**		**1,127,125**	**79,805**	**1,206,930**
14	Offsetting Market Revenues				
15	CAISO Market Revenues	Chapter 8	(812,991)		(812,991)
16	Balancing Account Amortization				
17	DCEOBA	Chapter 10	18,953		18,953
18	Subtotal Net Cost (Line 13 + Line 15 + Line 17)		333,086	79,805	412,892
19					
20	RF&U (PG&E) + FF&U (SCE) and FF&U (SDG&E)[c]	Chapter 12	4,618	897	5,516
21	**DCEO Revenue Requirement for Ratesetting**		**337,705**	**80,703**	**418,407**

Notes:
(a) Amounts in 2025 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

Q10 IS THE COMPANY'S REVENUE REQUIREMENT FOR SETTING THE DCNBC IN 2025 REASONABLE?

A No. The Company's revenue requirement used to determine the DCNBC is not reasonable because it does not reflect a comparison of costs and billing units in the same year the DCNBC will be charged. As a result, PG&E's proposed methodology does not result in a just and reasonable DCNBC. The Company used a multi-year time period (2023-2025) to accumulate Diablo Canyon life extension costs, allocated those costs among the IOUs, and divided by 2025 projected class sales to produce utility class-specific DCNBC charges for 2025. This procedure is not consistent with the Commission's stated objective of extending Diablo Canyon's life and development of a rational non-bypassable charge. In D.23-12-036, the Commission stated, "the public policy underlying the extended operations at Diablo Canyon must be considered when developing a rational rate design proposal."[13]

A procedure that is more reasonable, rational, and consistent with protecting the public is to develop the DCNBC charge by measuring the life extension cost and billing units in the same time period – that is, use a consistent test year data set to develop a DCNBC rate.

Q11 WHAT METHODOLOGY DO YOU RECOMMEND THAT THE COMMISSION APPROVE FOR SETTING THE DCNBC CHARGE?

A As stated above, I recommend a more stable structure based on a test year concept. This approach would limit the net revenue requirement used to develop the 2025 DCNBC rate to 2025 projected Diablo Canyon costs, utility demands, and sales.

Q12 DOES YOUR 2025 TEST YEAR INCLUDE COSTS FROM 2023 AND 2024?

[13] D.23-12-036 at p. 73 (emphasis added).

A No. I recommend excluding from the 2025 test year the $18.935 million of 2023 costs shown on PG&E's Table 1-2 as the Diablo Canyon Extended Operations Balancing Account ("DCEOBA"). The DCEOBA includes $17 million of employee retention expense and $1.9 million of payroll taxes incurred between September 2023 and December 2023. However, the Commission issued D.23-12-036 on December 15, 2023. The utilities have not proven that these costs were incurred after the Commission approved the life extension of Diablo Canyon and have not been offset by CAISO revenue in 2023 post approval.

Therefore, the utilities have not proven that these 2023 cost are incremental life extension cost nor how much of the incremental costs were recovered in CAISO revenue. I question whether any costs from before this decision date should be included.

In addition, as explained below, PG&E's 2024 incremental life extension costs are offset by the 2024 CAISO revenues, noting that liquidated damages cost are removed from my analysis for the reasons discussed below, therefore the utilities will fully recover liquidated damages in DCNBC charges in 2025 and 2026.

Q13 PLEASE DESCRIBE YOUR ANALYSIS WHERE THE CAISO MARKET REVENUES FOR DIABLO CANYON PROVIDE RECOVERY OF DIABLO CANYON LIFE EXTENSION COSTS IN CALENDAR YEAR 2024.

A My analysis is detailed in Schedule MPG-1, which shows PG&E's estimated cost of extending Diablo Canyon operations during calendar year 2024. My schedule shows that the life extension costs PG&E will incur for Diablo Canyon in calendar year 2024 is offset by CAISO market revenues PG&E estimates it will recover in 2024, excluding the liquidated damage cost.

The exception is the amount of Liquidated Damages PG&E included for 2024 because a DCNBC charge was not yet in effect in 2024. For the reasons described below, I propose that PG&E should limit collection of costs to cover Diablo Canyon liquidated damages to the periods in which the current DCNBC licenses are in effect. Therefore, I removed these costs from 2024 in my schedule that shows a revenue surplus of $8.1 million in 2024.

When calculating the revised 2024 life extension revenue requirement on Schedule MPG-1, I excluded several proposed escalators and/or Liquidated Damages payments that PG&E included for 2024. I eliminated PG&E's proposed management fee escalator in 2024 for the same reasons described below where I describe my development of a 2025 net revenue requirement to then determine 2025 DCNBC rates. I also removed PG&E's proposed Liquidated Damages collections for 2024, which reduces the DCNBC rate charged to customers without financially harming PG&E. Specifically, the Company is entitled to recover these liquidated damages costs over the full life extension period, up to $300 million.[14] PG&E's projections show the Company will recover this $300 million maximum amount through DCNBC rates collected over 2025 and 2026.[15] Additional Liquidated Damage charges beyond 2026 can

[14] Section 712.8(g).
[15] $200 million will be collected in 2025, and $100 million can be collected in 2026. This will produce the maximum $300 million reserve, which will be collected via the DCNBC after it goes into effect.

permit the replenishment of the reserve if replacement capacity must be procured for DC unplanned outages, causing the reserve to fall below $300 million.

Q14 PLEASE DESCRIBE YOUR RECOMMENDED NET REVENUE REQUIREMENT FOR LIFE EXTENSION COSTS FOR DIABLO CANYON FOR USE IN DEVELOPING THE 2025 DCNBC CHARGE.

A My recommended net revenue requirement for developing 2025 DCNBC rates is $294.303 million, as outlined in **Table 3**, below. This table compares my estimated 2025 net revenue (columns 4-5) with PG&E's proposed multi-year net revenue requirement (columns 1-3) presented in Chapter 1 of PG&E's Prepared Testimony on Table 1-2. In total, I recommend a $124.104 million decrease to PG&E's proposal.

TABLE 3

Recommended 2025 Net Revenue Requirement
($000)

		PG&E Proposed			EPUC Recommended		
Line	**Description**	**Statewide**	**PG&E**	**Total**	**Statewide**	**PG&E**	**Total**
		(1)	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**
	Operational Revenue Requirement						
1	Operation and Maintenance Cost Forecast	$ 633,164		$ 633,164	$ 564,184		$ 564,184
2	Resource Adequacy Substitution Capacity	76,444		76,444	67,937		67,937
3	Subtotal Operational Revenue Requirement	$ 709,608		$ 709,608	$ 632,121		$ 632,121
	Management, Performance Fees, and Liquidated Damages						
4	Fixed Management Fee	$ 79,079			$ 67,397		
5	State & Federal Taxes	33,633			-		
6	Management Fee	$ 112,711		$ 112,711	$ 67,397		$ 67,397
7	Liquidated Damages	225,000		225,000	200,000		200,000
8	Volumetric Performance Fee	79,805		79,805	70,071		70,071
9	PG&E Specific Volumetric Performance Fee	-	79,805	79,805	-	70,071	70,071
10	Subtotal Statutory Fees	$ 417,517	$ 79,805	$ 497,322	$ 337,469	$ 70,071	$ 407,540
11	Total Cost Forecast	$ 1,127,125	$ 79,805	$ 1,206,930	$ 969,590	$ 70,071	$ 1,039,661
	Offsetting Market Revenues						
12	CAISO Market Revenues	$ (812,991)		$ (812,991)	$ (749,202)		$ (749,202)
	Balancing Account Amortization						
13	DCEOBA	$ 18,953		$ 18,953	$ -		$ -
14	Subtotal Net Costs	$ 333,086	$ 79,805	$ 412,892	$ 220,388	$ 70,071	$ 290,460
15	RF&U (PG&E) + FF&U (SCE) + FF&U(SDG&E)	$ 4,618	$ 897	$ 5,516	$ 3,056	$ 788	$ 3,844
16	**DCEO Revenue Requirement for Ratesetting**	**$ 337,705**	**$ 80,703**	**$ 418,407**	**$ 223,444**	**$ 70,859**	**$ 294,303**
17	**Difference**				**$ (114,261)**	**$ (9,843)**	**$ (124,104)**

Source:
Chapter 11 workpapers.

The differences between my estimated net revenue for a 2025 DCNBC charge and that proposed by PG&E are the result of the following adjustments:

1. First, I limited my development of a net revenue requirement for the 2025 DCNBC rate to the 2025 test year, which aligns with the projected sales units for the utilities used to develop the DCNBC rate.

2. Second, I adjusted PG&E's proposed Management Fee. The Company is entitled to a Management Fee of $50 million per unit per year collected through revenue for each of the two Diablo Canyon units in lieu of an equity return on this facility.[16] The $50 million per

[16] Section 712.8(f)(5).

unit per year was designed to give PG&E compensation below their historical average return.[17] PG&E proposes to gross up the Management Fee for federal and state income taxes, which increases the $50 million per unit per year to $56.35 million per unit per year. For the reasons outlined below, PG&E's proposal to gross up the $50 million per unit per year Management Fee is not justified. I also recommend that the Commission decline to adopt PG&E's proposed escalation adjustment (which the Commission does not require) to the $450 million management fee, which is about a $3.3 million adjustment in 2025.

3. The third adjustment limits the amount of Liquidated Damages included in the 2025 revenue requirement. PG&E included approximately 18 months of allowable $12.5 million per month fee for liquidated damages to be included in the revenue to be collected in 2025. However, the DC Units 1 and 2 will only have a combined 16 months of post-license termination operation by the end of 2025. I recommend limiting the allowable recovery of Liquidated Damages to the $12.5 million per month allowed by Section 712.8(g) to 16 months of operation in life extension operation in calendar year 2025.[18] This reduces the amount of Liquidated Damages included in the net revenue for the 2025 DCNBC from $225 million to $200 million. PG&E is allowed to collect a maximum Liquidated Damage accrual from customers of up to $300 million. PG&E will collect this reserve in less than two years of the five-year life extension.

4. Fourth, I updated the CAISO market revenue forecast based on NP15 forward price data for 2025. I demonstrate that 2024 life extension costs are fully recovered by 2024 CAISO market revenue, except for the liquidation damage cost that is recovered in DCNBC changes in 2025 and 2026. The Company assumes $68.57/MWh in projected CAISO market revenue from operating Diablo Canyon in 2025. PG&E's own forward price curve for calendar year 2025 based on Platt's data provides alternatives for forward price curves and supports a 2025 price of $73.40/MWh to develop the 2025 net revenue requirement. Of course, this price will be updated in subsequent DCNBC true-ups to reflect actual market revenue, but using the adjusted forward price provides the greatest customer protections from the risk of making excess payments prior to the true-ups.

---

[17] SB 846 Senate Floor Analysis at p. 12.

[18] The Company states that Diablo Canyon Unit 1's current license will expire November 2, 2024, and Unit 2's license will expire August 26, 2025 (Chapter 1 at p. 1-10). This produces approximately 12 months of life extension operation for Unit 1 and approximately four months of life extension operation for Unit 2 in calendar year 2025.

Q15 PLEASE EXPLAIN WHY PG&E'S PROPOSAL TO GROSS UP THE MANAGEMENT FEE IN DEVELOPING A NET REVENUE REQUIREMENT IS UNREASONABLE.

A PG&E addresses the recovery of the Fixed Payment from all LSE customers in Chapter 7, on page 7-2. PG&E quotes Section 712.8(f)(6)(A) as follows:

> In lieu of a rate-based return on investment and in acknowledgment of the greater risk of outages in an older plant that the operator could be held liable for, the commission shall authorize the operator to recover in rates a fixed payment of fifty million dollars ($50,000,000), in 2022 dollars, for each unit for each year of extended operations, subject to adjustment in subparagraphs (B) to (D), inclusive. **The amount of the fixed payment shall be adjusted annually by the commission using commission-approved escalation methodologies and adjustment factors.** (Emphasis added.)

As outlined above, the $50 million stated in 2022 dollars is subject to certain escalators, but it is not subject to an income tax gross-up fee.

Q16 WHAT ESCALATOR DID PG&E INCLUDE TO THE MANAGEMENT FEE TO DERIVE COSTS FOR THE 2025 TEST YEAR?

A PG&E used a cumulative escalation factor of 2.90% in 2023, 3.66% in 2024 and 4.90% in 2025 (with 2022 as the base year).[19]

Q17 IS PG&E'S ESCALATION FACTOR FOR THE MANAGEMENT FEE REASONABLE?

---

[19] Chapter 7 at p. 7-5.

A No. Although Section 712.(g) contemplates escalation methodologies, it does not require the Commission to approve any specific methodology. I recommend the Commission reject PG&E's proposed escalation factor because the Fixed Payments collected from customers provides PG&E with ample consideration for a management fee on this investment, and adequately compensates PG&E.

Q18 PLEASE DESCRIBE WHY THE LIQUIDATED DAMAGES INCLUDED IN COST OF SERVICE SHOULD BE LIMITED TO 16 MONTHS AND NOT 18 MONTHS AS PROPOSED BY PG&E.

A PG&E states that Section 712.8(g) prescribes:

> The commission shall authorize and fund as part of the charge under paragraph (1) of subdivision (l), the Diablo Canyon Extended Operations liquidated damages balancing account in the amount of twelve million five hundred thousand dollars ($12,500,000) each month for each unit until the liquidated damages balancing account has a balance of three hundred million dollars ($300,000,000).[20]

As shown above, PG&E is allowed to recover from customers $12.5 million per month for each unit for liquidated damages for the post-operating license period, or life extension period, up to a total amount of $300 million. Allowing the Company to develop a DCNBC rate for calendar year operation of these units will provide for sufficient recovery of these costs and essentially create a deferral balance over 12 months[21] up to the $300 million permitted by the rule. For 2025, Units 1 and 2 will be in effect for approximately 16 months, which equates to a 2025 liquidated reserve collection of around $200 million.

[20] Chapter 7 at p. 7-8.
[21] $12.5 million x 2 units x 12 months = $300 million.

For 2026, the net revenue requirement for the DCNBC rate can be adjusted to reflect the additional funding needed to meet the maximum Liquidated Damages reserve, and to reimburse PG&E for any funds expended from this reserve for replacement capacity in 2025.

Q19 PLEASE EXPLAIN WHY YOU BELIEVE THE COMPANY HAS UNDERSTATED CAISO MARKET REVENUE IN 2025.

A PG&E's CAISO market reference price used to develop the CAISO generation revenues is shown in Chapter 8, page 8-3, Table 8-1. For 2024 CAISO market revenues, PG&E used a price of $78.44/MWh and for 2025, it used a price $68.57/MWh. These prices reflect adjustments to the forward price curve to reflect a portfolio weighting factor based on historic Diablo Canyon CAISO energy market revenues.[22] On a historic basis, for the period 2021-2023, PG&E's workpapers show an average DC market revenue price of $67.59/MWh.[23] PG&E states that it will update the market reference price calculation using updated NP15 Platt's price curves provided by the Commission's part of the standard Power Charge Indifference Adjustment ("PCIA") energy index update process.[24]

Q20 IS PG&E'S CAISO MARKET PRICE REASONABLE FOR SETTING A NET REVENUE REQUIREMENT FOR DIABLO CANYON IN 2025?

[22] Chapter 8 at p. 8-2.
[23] PG&E's Chapter 8 workpapers, Attachment 15_DCPP-ExtendedOperations2025-Forecast_WP_PGE_20240329-Ch08_Forward Power Price Derivation-PUB.
[24] Chapter 8 at p. 8-2.

A No. PG&E used a 2025 price forecast of $68.57/MWh. PG&E's own data indicates an average forward price curve in the NP15 market is $73.40/MWh, as outlined in Schedule MPG-2, using consensus projections for forward price curves in the CAISO NP15 market region published by OTC Global Holdings ("OTCGH"). The same source shows that the 2025 forward NP-15 price is higher than both PG&E's $68.57/MWh and the 2024 forward price of $68.33/MWh. Thus, PG&E projections reflect a lower CAISO price in 2025 than is justified.

PG&E's projected decline in the 2025 CAISO market price relative to 2024 does not align with independent market participants' outlooks for prices in the 2024 and 2025 CAISO market. Further, PG&E's forward price for 2025 seems to anticipate reversion to the price that existed on average over the period 2021-2023. In contrast, market outlooks reflect forward-looking assessments of generation resource capacity constraints, electric and gas delivery constraints, and general market factors that are likely to drive up the cost of energy in the CAISO energy market in 2025.[25] Thus, I believe it is more reasonable to increase the CAISO market price used to set PG&E's DC revenue requirement from $68.57/MWh to the forward price curve projection of $73.40/MWh.

Because this price will be updated annually and can be adjusted to actual nodal pricing for Diablo Canyon, I recommend setting a net revenue

[25] https://www.eoxlive.com/market-data/power-forward-curves/.

requirement based on the assumption that Diablo Canyon will earn the average forward price curve for energy prices in this zone.

ALLOCATE THE NET REVENUE REQUIREMENT ACROSS PG&E, SCE AND SDG&E

Q21 HOW DID THE COMPANY DEVELOP THE REALLOCATION OF THE REVENUE REQUIREMENT FOR LIFE EXTENSION OF DIABLO CANYON ACROSS PG&E, SCE AND SDG&E?

A Volumetric performance fees were assigned directly to PG&E and the remaining costs were allocated among the three Utilities based on the 12-CP factors shown in Chapter 12 on Table 12-2. These allocation factors reflect the capacity contribution of Diablo Canyon to each of the three IOUs, and represent appropriate allocation of these costs based on the capacity benefits provided to each of the IOUs. I relied on the Company's 12-CP allocators developed in Table 12-2 for allocating my revised revenue requirements among the Utilities. The allocators are copied in **Table 4**, below.

TABLE 4

Copy of PG&E Table 12-2
2024 CEC 12-CP Forecast - CPUC Jurisdictional

IOU	Source	Duration	Term	MW	Percent
PG&E	2024 CEC 12-CP	1-Year	2024	181,744	45.0%
SCE	2024 CEC 12-CP	1-Year	2024	180,729	44.7%
SDG&E	2024 CEC 12-CP	1-Year	2024	41,605	10.3%
Total				404,078	100.0%

Q22 WHAT IS THE REVISED ALLOCATION OF THE ADJUSTED NET REVENUE REQUIREMENT ACROSS THE UTILITIES?

A Based on the same allocation proposed by PG&E,[26] my suggested allocation of the revised net revenue requirement among the Utilities is as follows:

TABLE 5

Recommended Net Revenue Requirement Allocation
($000)

		2025 Test Year			
Line	**Description**	**Total**	**PG&E**	**SCE**	**SDG&E**
		(1)	**(2)**	**(3)**	**(4)**
1	12-CP Forecast - CPUC Jurisdictional		45.0%	44.7%	10.3%
	Operational Revenue Requirement				
2	Operation and Maintenance Cost Forecast	$ 564,184	$ 253,755	$ 252,339	$ 58,090
3	Resource Adequacy Substitution Capacity	67,937	30,556	30,386	6,995
4	Subtotal Operational Revenue Requirement	$ 632,121	$ 284,312	$ 282,725	$ 65,085
	Management, Performance Fees, and Liquidated Damages				
5	Fixed Management Fee	$ 67,397			
6	State & Federal Taxes	-			
7	Management Fee	$ 67,397	$ 30,314	$ 30,144	$ 6,939
8	Liquidated Damages	200,000	89,955	89,453	20,592
9	Volumetric Performance Fee	70,071	31,516	31,340	7,215
10	PG&E Specific Volumetric Performance Fee	70,071	70,071	-	-
11	Subtotal Statutory Fees	$ 407,540	$ 221,856	$ 150,937	$ 34,747
12	Total Cost Forecast	$ 1,039,661	$ 506,168	$ 433,662	$ 99,831
	Offsetting Market Revenues				
13	CAISO Market Revenues	$ (749,202)	$ (336,971)	$ (335,091)	$ (77,140)
	Balancing Account Amortization				
14	DCEOBA	$ -	$ -	$ -	$ -
15	**Subtotal Net Costs**	**$ 290,460**	**$ 169,196**	**$ 98,572**	**$ 22,692**
16	Uncollectibles, Franchise Fees, and SF Revenue Fee Factor		1.1245%	1.1061%	3.7493%
17	RF&U	$ 3,844	$ 1,903	$ 1,090	$ 851
18	**DCEO Revenue Requirement for Ratesetting**	**$ 294,303**	**$ 171,099**	**$ 99,662**	**$ 23,542**

Source:
Chapter 11 workpapers.

My suggested allocation of the revised net revenue requirement among the three IOU utilities was developed in the same manner as PG&E's proposed

[26] Chapter 12, Table 12-4.

allocation presented in Table 12-12 of its testimony, with my recommended revenue input adjustments.

DEVELOPMENT OF DCNBC RATE CALCULATION

Q23 BASED ON YOUR REVISED REVENUE REQUIREMENT, HOW DOES THAT CHANGE THE DCNBC RATE CALCULATION FOR PG&E?

A **Table 6**, below, reflects PG&E's class-specific DCNBC rates based on my revised net revenue requirement.

TABLE 6

PG&E
Diablo Canyon Non-bypassable Charge

Line	Customer Class	12-CP Allocation Factor	Allocated Revenue Requirement (RRQ) ($000)	Sales Forecast (MWh)	2025 DCNBC Rate ($/kWh)
		(1)	(2)	(3)	(4)
1	Residential	47.3%	$80,877	27,668,515	$0.00292
2	Small Commercial	9.7%	$16,640	8,087,321	$0.00206
3	Med & Large Commercial	23.7%	$40,530	22,215,342	$0.00182
4	Streetlights	0.2%	$387	253,430	$0.00153
5	Standby	0.7%	$1,237	527,585	$0.00235
6	Agriculture	5.8%	$9,923	5,541,234	$0.00179
7	Industrial	12.6%	$21,505	15,951,289	$0.00135
8	Total		$171,099	80,244,716	

The rates reflected in **Table 6** were developed in the same manner as PG&E's proposed DCNBC rates, as presented in Chapter 12 of PG&E's Prepared Testimony on Table 12-5.[27]

[27] Chapter 12 at p. 12-10.

Q24 DID YOU ALSO DEVELOP A DCNBC RATE FOR SCE BASED ON YOUR REVISED REVENUE REQUIREMENT?

A Yes. Using the same methodology that PG&E proposed for SCE's DCNBC rate calculation provided in Chapter 12 on Table 12-8,[28] I developed SCE class-specific DCNBC rates based on my revised net revenue requirement, as shown in **Table 7**, below.

TABLE 7

Southern California Edison
Diablo Canyon Non-bypassable Charge

Line	Customer Class	12-CP Allocation Factor	Allocated Revenue Requirement (RRQ) ($000)	Sales Forecast (MWh)	2025 DCNBC Rate ($/kWh)
		(1)	(2)	(3)	(4)
1	Domestic	43.9%	$43,734	25,927,049	$0.00169
2	TOU-GS-1	7.4%	$7,358	5,855,680	$0.00126
3	TC-1	0.0%	$45	54,106	$0.00083
4	TOU-GS-2	15.1%	$15,000	13,363,394	$0.00112
5	TOU-GS-3	8.9%	$8,899	8,047,822	$0.00111
6	TOU-8-SEC	8.2%	$8,221	7,850,441	$0.00105
7	TOU-8-PRI	5.3%	$5,274	5,749,147	$0.00092
8	TOU-8-SUB	5.0%	$5,001	6,126,827	$0.00082
9	TOU-8-Standby-SEC	0.2%	$152	144,877	$0.00105
10	TOU-8-Standby-PRI	0.5%	$479	522,439	$0.00092
11	TOU-8-Standby-SUB	2.0%	$1,957	2,397,759	$0.00082
12	TOU-PA-2	1.7%	$1,733	1,958,072	$0.00089
13	TOU-PA-3	1.5%	$1,445	1,737,523	$0.00083
14	Street Lighting	0.4%	$362	459,397	$0.00079
15	Total		$99,662	80,194,531	

[28] Chapter 12 at p. 12-14.

Q25 DID YOU ALSO DEVELOP A REVISED DCNBC CHARGE FOR SDG&E?

A Yes. Using PG&E's methodology,[29] I developed the class-specific DCNBC rates for SDG&E customers based on my revised revenue requirement, as presented below in **Table 8**.

TABLE 8

San Diego Gas & Electric
Diablo Canyon Non-bypassable Charge

Line	Customer Class	12-CP Allocation Factor (1)	Allocated Revenue Requirement (RRQ) ($000) (2)	Sales Forecast (MWh) (3)	2025 DCNBC Rate ($/kWh) (4)
1	Residential	45.3%	$10,280	7,323,388	$0.00140
2	Small Commercial	11.0%	$2,496	2,365,308	$0.00106
3	Med & Large Commercial	42.3%	$9,598	9,696,893	$0.00099
4	Ag	1.1%	$240	362,221	$0.00066
5	Streetlight	0.3%	$77	76,256	$0.00101
6	Total		$22,692	19,824,066	

Q26 WAS THIS TESTIMONY PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A Yes.

Q27 TO THE EXTENT THIS TESTIMONY REFLECTS FACTS, ARE THE FACTS TRUE AND CORRECT TO THE BEST OF YOUR KNOWLEDGE?

A Yes.

[29] Chapter 12 at p. 12-17, Table 12-11.

Q28 TO THE EXTENT THIS TESTIMONY REFLECTS PROFESSIONAL OPINION, ARE THE OPINIONS YOUR BEST PROFESSIONAL OPINION?

A Yes.

Q29 DO YOU ADOPT THIS TESTIMONY AS YOUR SWORN TESTIMONY IN THIS PROCEEDING?

A Yes.

Q30 DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

<u>Qualifications of Michael P. Gorman</u>

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A In 1983 I received a Bachelor of Science Degree in Electrical Engineering from Southern Illinois University, and in 1986, I received a Master's Degree in Business Administration with a concentration in Finance from the University of Illinois at Springfield. I have also completed several graduate level economics courses.

In August of 1983, I accepted an analyst position with the Illinois Commerce Commission ("ICC"). In this position, I performed a variety of analyses for both formal and informal investigations before the ICC, including: marginal cost of energy, central dispatch, avoided cost of energy, annual system production costs, and working capital. In October of 1986, I was promoted to the position of Senior Analyst. In this position, I assumed the additional responsibilities of technical leader on projects, and my areas of responsibility were expanded to include utility financial modeling and financial analyses.

In 1987, I was promoted to Director of the Financial Analysis Department. In this position, I was responsible for all financial analyses conducted by the Staff. Among other things, I conducted analyses and sponsored testimony before the ICC on rate of return, financial integrity, financial modeling and related issues. I also supervised the development of all Staff analyses and testimony on these same issues. In addition, I supervised the Staff's review and recommendations to the Commission concerning utility plans to issue debt and equity securities.

In August of 1989, I accepted a position with Merrill-Lynch as a financial consultant. After receiving all required securities licenses, I worked with individual investors and small businesses in evaluating and selecting investments suitable to their requirements.

In September of 1990, I accepted a position with Drazen-Brubaker & Associates, Inc. (“DBA”). In April 1995, the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and Staff. Since 1990, I have performed various analyses and sponsored testimony on cost of capital, cost/benefits of utility mergers and acquisitions, utility reorganizations, level of operating expenses and rate base, cost of service studies, and analyses relating to industrial jobs and economic development. I also participated in a study used to revise the financial policy for the municipal utility in Kansas City, Kansas.

At BAI, I also have extensive experience working with large energy users to distribute and critically evaluate responses to requests for proposals ("RFPs") for electric, steam, and gas energy supply from competitive energy suppliers. These analyses include the evaluation of gas supply and delivery charges, cogeneration and/or combined cycle unit feasibility studies, and the evaluation of third-party asset/supply management agreements. I have participated in rate cases on rate design and class cost of service for electric, natural gas, water and wastewater utilities. I have also analyzed commodity pricing indices and forward pricing methods for third party supply agreements, and have also conducted regional electric market price forecasts.

In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

Q HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

A Yes. I have sponsored testimony on cost of capital, revenue requirements, cost of service and other issues before the Federal Energy Regulatory Commission and numerous state regulatory commissions including: Alaska, Arkansas, Arizona, California, Colorado, Delaware, the District of Columbia, Florida, Georgia, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Montana, Nevada, New Hampshire, New Jersey, New Mexico, New York, North Carolina, North Dakota, Ohio, Oklahoma, Oregon, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Washington, West Virginia, Wisconsin, Wyoming, and before the provincial regulatory boards in Alberta, Nova Scotia, and Quebec, Canada. I have also sponsored testimony before the Board of Public Utilities in Kansas City, Kansas; presented rate setting position reports to the regulatory board of the municipal utility in Austin, Texas, and Salt River Project, Arizona, on behalf of industrial customers; and negotiated rate disputes for industrial customers of the Municipal Electric Authority of Georgia in the LaGrange, Georgia district.

Q PLEASE DESCRIBE ANY PROFESSIONAL REGISTRATIONS OR ORGANIZATIONS TO WHICH YOU BELONG.

A I earned the designation of Chartered Financial Analyst ("CFA") from the CFA Institute. The CFA charter was awarded after successfully completing three examinations which covered the subject areas of financial accounting, economics, fixed income and equity valuation and professional and ethical conduct. I am a member of the CFA Institute's Financial Analyst Society.

502874

Pacific Gas and Electric Company

Annual Revenue Requirements
($000)

Line	Description	2023 (1)	2024 (2)	2025 (3)	Total (4)
	Operational Revenue Requirement				
1	Operation and Maintenance Cost Forecast		$ 68,980	$ 564,184	$ 633,164
2	Resource Adequacy Substitution Capacity		8,507	67,937	76,444
3	Subtotal Operational Revenue Requirement		$ 77,487	$ 632,121	$ 709,608
	Management, Performance Fees, and Liquidated Damages				
4	Fixed Management Fee		$ 8,060	$ 70,701	$ 78,761
5	State & Federal Taxes		-	30,070	30,070
6	Management Fee		$ 8,060	$ 100,771	$ 108,831
7	Liquidated Damages		-	200,000	200,000
8	Volumetric Performance Fee		9,734	70,071	79,805
9	PG&E Specific Volumetric Performance Fee		9,734	70,071	79,805
10	Subtotal Statutory Fees		$ 27,528	$ 440,913	$ 468,441
11	Total Cost Forecast		$ 105,014	$ 1,073,034	$ 1,178,049
	Offsetting Market Revenues				
12	CAISO Market Revenues		$ (113,089)	$ (699,901)	$ (812,991)
	Balancing Account Amortization				
13	DCEOBA	$ 18,953	$ -	$ -	$ 18,953
14	**Subtotal Net Costs**	**$ 18,953**	**$ (8,075)**	**$ 373,133**	**$ 384,011**

Source:
Chapter 11 workpapers.

Pacific Gas and Electric Company

CAISO NP 15 Forward Prices
As Of January 31, 2024

Line	Month	2024	2025	Difference
		(1)	(2)	(3)
1	January	77.96	105.07	27.11
2	February	55.49	79.30	23.80
3	March	51.88	58.91	7.03
4	April	47.36	48.14	0.78
5	May	40.13	40.19	0.06
6	June	55.10	58.60	3.50
7	July	77.23	79.26	2.04
8	August	92.11	96.93	4.82
9	September	84.11	81.60	(2.52)
10	October	65.92	60.61	(5.31)
11	November	72.14	67.85	(4.28)
12	December	100.55	104.36	3.80
13	**Average**	**68.33**	**73.40**	**5.07**

Source:
OTCGH, 'EOD_PW_20240131_1430.xlsx, "Fixed Prices - Mid" tab.