

**Application 25-05-009
Exhibit No. CLECA-01**

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

**Application of Pacific Gas and Electric
Company for Authority, Among Other
Things, to Increase Rates and Charges for
Electric and Gas Service Effective on
January 1, 2027. (U 39 M)**

**Application 25-05-009
(Filed May 15, 2025)**

**Opening Testimony of
Sam Harper and John Holler
on behalf of
California Large Energy Consumers Association**

February 13, 2026

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1 compete, and, importantly, for customers to make prudent investment decisions to
2 electrify.

3 We are at a critical crossroads of potential load growth from electrification and
4 economic development that could deliver dramatic long-term affordability improvements
5 if more customers utilize more electricity and spread fixed costs across more megawatts.
6 Electrification of transportation, buildings, and industrial processes is an essential
7 element of the state’s policy goals.³ If these electrification efforts are implemented
8 properly, the associated load growth holds a perhaps once-in-a-generation opportunity to
9 deliver significant rate reductions by expanding the customer base and improving asset
10 utilization, all while advancing core state environmental policy goals.⁴

11 However, this result is not guaranteed. To be successful, the load growth must
12 occur, driven by individual customer’s economic decisions. And load growth must
13 outpace higher utility spending. Prudent investments to build out electrical infrastructure
14 are no doubt necessary to improve reliability, facilitate load growth, and integrate new
15 resources. Nonetheless, massive proactive investments that are not aligned with the
16 magnitude and timing of hoped-for, yet uncertain load growth, are not prudent. Large
17 increases in operating costs and unconstrained two-way balancing accounts are not
18 prudent. Billions in spending on undergrounding without adequate justification is not
19 appropriate. Massively increasing revenue requirements that will lead to increased
20 customer rates amidst an existing affordability crisis is not prudent.

³ California Independent System Operator, *2022–2026 Strategic Plan* at 4 (noting projected growth in “electrification of transportation, building and other industries” as part of California’s decarbonization pathway under SB 100).

⁴ PG&E, *Electrification Impacts Study Part 2 Report*, at 14 (Jan. 28, 2026) (“Electrification growth may provide downward pressure on distribution rates by as much as 25% by 2040.”).

1 regulatory proposals. Mr. Hollers’s statement of qualifications is included as Attachment
2 B to this testimony. CLECA represents a broad array of industrial and manufacturing
3 customers for whom electricity comprises a significant portion of their cost of
4 production. These customers are responsible for providing essential goods and services
5 necessary for daily life, contribute meaningfully to the state economy, pay millions of
6 dollars in state and local taxes, and provide desperately needed high-quality jobs in
7 California. CLECA members compete across state lines, and many are designated by the
8 California Public Utilities Commission (Commission) as Emissions-Intensive and Trade-
9 Exposed (EITE), with the associated risk of emissions leakage if production shifts out of
10 state—meaning “emissions could remain unchanged or even increase”.⁵ CLECA
11 members depend on affordable electricity rates to effectively compete across state lines,
12 and their long-term success is essential to achieving the state’s policy goals. CLECA
13 members are actively pursuing electrification and other decarbonization investments that
14 depend upon PG&E’s electric rate affordability to be economically feasible. Notably,
15 CLECA members have not typically participated in the base revenue requirement setting
16 phase of PG&E’s GRC due to the significant time and costs required to do so. Their
17 decision to participate now underscores the magnitude of concern with the revenue
18 requirement request in this proceeding and the potential impact on these customers’
19 operations.

⁵ See CPUC, *California Industry Assistance*, available at: <https://www.cpuc.ca.gov/industries-and-topics/natural-gas/greenhouse-gas-cap-and-trade-program/california-industry-assistance>; *see also*, <https://ww3.arb.ca.gov/regact/2010/capandtrade10/capisor.pdf#page=56>.

1 **Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

2 **A** The purpose of this testimony is to address policy concerns with PG&E’s test
3 year (TY) 2027 GRC Application (A.) 25-05-009 (Application). Specifically, this
4 testimony provides an assessment of the current affordability crisis and highlights the
5 impact of PG&E’s proposed revenue requirement increases on affordability and the
6 associated policy consequences, including on customer electrification investment
7 decisions. We then provide recommendations with the goal of meaningful electricity rate
8 reductions in this GRC cycle, assuming reasonable load growth forecasts, across all
9 customer sectors.

10 **Q HOW IS YOUR TESTIMONY ORGANIZED?**

11 **A** First, we provide a summary of recommendations. Then, we provide an overview
12 of CLECA member operations and interests in this proceeding, followed by a discussion
13 of the CLECA member electric rate affordability, and impacts of this Application on
14 rates.

15 Next, we provide an assessment of PG&E’s affordability and proposed spending.
16 We assess the adequacy of PG&E’s affordability efforts, identify spending proposals that
17 are not reasonably aligned with affordability, and identify several accounting adjustments
18 necessary to accurately compare the requested revenue requirement across GRCs. Then,
19 we assess PG&E’s risk management programs using risk-neutral Cost-Benefit Ratios
20 (CBRs) and the sequencing and prioritization of load growth investments. Finally, we
21 assess the use of two-way balancing and memorandum accounts for reasonableness.

1 **SUMMARY OF RECOMMENDATIONS**

2 **Q PROVIDE A SUMMARY OF YOUR POSITIONS IN THIS TESTIMONY.**

3 **A** CLECA takes the following positions regarding the PG&E TY 2027 GRC

4 Application:

- 5 ➤ The Commission should recognize the seriousness of current electric rate
6 unaffordability, evaluate PG&E’s revenue requirement on a basis that
7 accounts for the effects of accounting and procedural adjustments, and only
8 approve spending in this GRC if it results in declining electric rates across the
9 entire 2027-2030 GRC period under all reasonable load-growth scenarios.
- 10 ➤ The Commission should evaluate PG&E’s risk management programs using
11 risk-neutral CBRs as the primary analytical reference, and require PG&E to
12 justify all program tranches with risk-neutral CBRs below 1 with explicit
13 findings demonstrating safety necessity, legal or regulatory obligation, or
14 clearly articulated non-quantifiable benefits.
- 15 ➤ The Commission should acknowledge the uncertainty of load growth
16 investments by magnitude, sector, timing, utility element, and location of
17 anticipated new customers and electrification demand; and the critical
18 importance of near-term affordability on individual decisions by ratepayers to
19 invest in electrification that could lead to load growth and a net decrease in
20 overall electric rates.
- 21 ➤ The Commission should direct PG&E to sequence and size load growth and
22 electrification-related investments based on observed load growth patterns and
23 realistic demand forecasts, to achieve net rate reductions over each year of this
24 GRC period.
- 25 ➤ The Commission should direct PG&E to sequence investments after
26 implementation of broadly available dynamic pricing, demand response, and
27 other load-shaping programs that incorporate price signals for transmission
28 and distribution; and incorporate dynamic load flexibility in its transmission
29 and distribution investment planning.
- 30 ➤ The Commission should prioritize and limit approved capital work in this
31 GRC to only those activities that are necessary, urgent, and that PG&E has
32 demonstrated it can reasonably execute within the GRC period.
- 33 ➤ The Commission should reject spending proposals that have not been
34 adequately justified in this Application:
- 35 1. Direct PG&E to freeze Administrative and General (A&G) spending at the
36 prior 2026 approved levels.

- 1 2. Apply rigorous scrutiny before approving any departmental or functional
2 headcount increases.
- 3 3. Direct PG&E to prioritize only the proposed power generation projects
4 necessary to be completed in the current GRC period. For any activity that
5 PG&E cannot demonstrate is urgent and infeasible for deferral, the
6 Commission should either reject the activity outright or approve it only on
7 a phased basis over two or more GRC cycles.
- 8 4. Reject the proposed \$99M PG&E Academy Building.
- 9 5. Reject PG&E's request for Undergrounding "bridge funding."
- 10 ➤ The Commission should take the following actions regarding balancing and
11 memorandum accounts:
 - 12 1. Constrain the use of two-way balancing and memorandum accounts to
13 circumstances where PG&E has demonstrated that such costs cannot be
14 adequately planned for and managed within the GRC-approved budget.
 - 15 2. Reject PG&E's proposal to expand the scope of the Hydro Licensing
16 Balancing Account.
 - 17 3. Reject PG&E's proposal to create the New Business Balancing Account.
 - 18 4. Direct PG&E to discontinue the Wildfire Mitigation Plan Memorandum
19 Account (WMPMA) and the Fire Risk Mitigation Memorandum Account
20 (FRMMA).
- 21 ➤ The Commission should be bold in protecting ratepayers from relentless rate
22 increases, and stalwart in setting just and reasonable electricity rates for the
23 TY 2027 GRC cycle based upon a more modest spending program, a more
24 realistic pace of load growth investments, and more rigorous cost control
25 incentives across GRC cycles.

26 CLECA MEMBERS OPERATIONS AND INTERESTS

27 **Q WHO ARE CLECA MEMBERS?**

28 **A** CLECA members are large industrial and manufacturing customers with facilities
29 served by PG&E that rely upon safe, reliable, clean, and affordable electricity.⁶ CLECA

⁶ CLECA members also have facilities in other Investor Owned Utility, Publicly Owned Utilities, and Community Choice Aggregation service territories throughout California.

1 member companies provide goods and services essential to the well-being of all
2 Californians, including materials for critical infrastructure, medical grade oxygen for
3 hospitals, and cold storage for food distribution.

4 **Q WHAT ARE THE INTERESTS OF CLECA MEMBERS IN THIS CASE?**

5 **A** CLECA members, like many other California ratepayers, are facing an
6 affordability crisis. CLECA member companies compete with facilities located in
7 neighboring western states, across the country, and in some cases, internationally. Energy
8 costs are a significant driver of CLECA member companies' competitiveness and impact
9 their ability to maintain or expand operations within the state. Additionally, many
10 member companies have set individual environmental targets that involve electrifying
11 portions of their operations or adopting carbon capture or other technologies that involve
12 consuming significantly more electricity. CLECA members' ability to operate
13 competitively and to economically execute these environmental strategies depends
14 directly on the price of electricity.

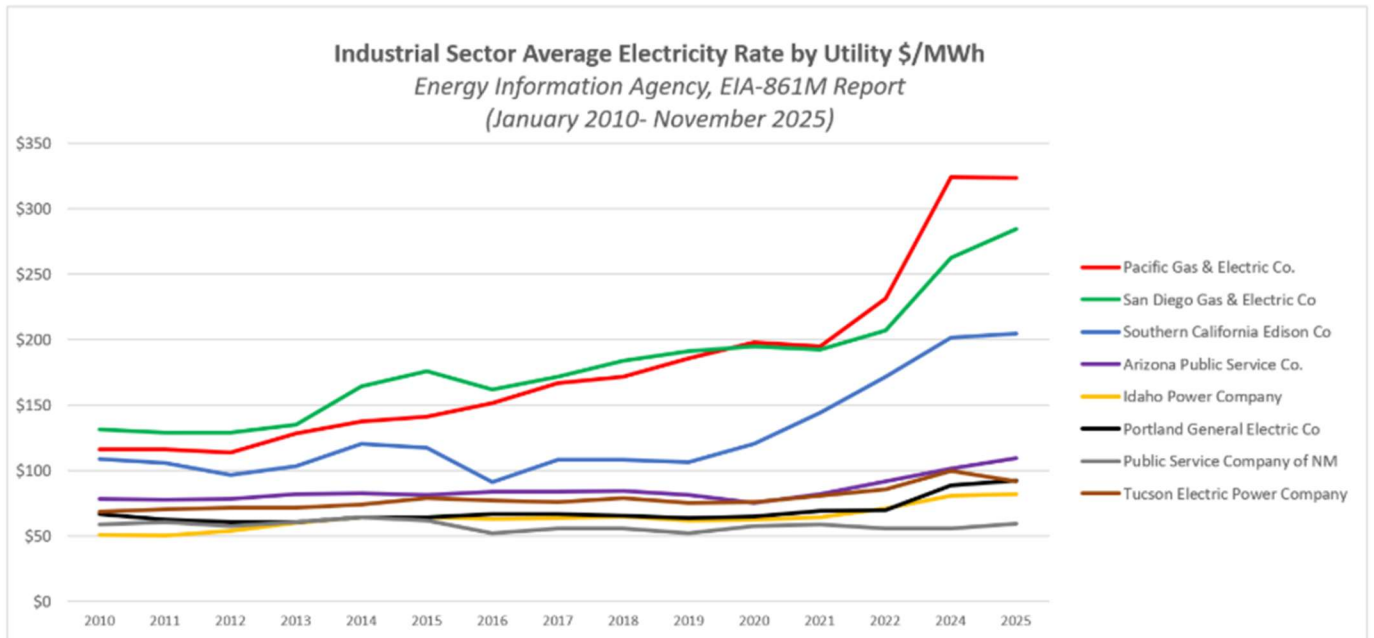
15 **CLECA MEMBER ELECTRIC RATE AFFORDABILITY AND IMPACTS OF**
16 **THIS APPLICATION ON RATES**

17 **Q WHAT IS THE CURRENT STATE OF INDUSTRIAL SECTOR**
18 **ELECTRIC RATE AFFORDABILITY?**

19 **A** California's electric rates for industrial sector customers are dramatically higher
20 than industrial sector rates of neighboring western states. This gap has grown
21 dramatically in recent years, in particular for PG&E industrial customers. PG&E now
22 holds the dubious distinction of having the highest industrial rates amongst the large
23 investor-owned utilities in California, and industrial rates over 300% of neighboring

1 western states – See Figure 1. Many of the CLECA members’ California facilities
 2 compete with operations located in neighboring states; lower electric rates in other states
 3 provide a strong competitive advantage to energy-intensive operations out of state, and
 4 put tremendous competitive pressure on operations looking to remain, expand, or
 5 electrify in California. This potential for economic and emissions leakage should be of
 6 great concern to the Commission.

7 **Figure 1**
 8 **Industrial Sector Average Electricity Rate by Utility \$/MWh⁷**



9
 10 **Q WHAT ARE THE POLICY IMPACTS OF RATE AFFORDABILITY**
 11 **ISSUES FACED BY THE CLECA MEMBERS?**

12 **A** CLECA members provide critical goods and services, and the current electric rate
 13 unaffordability limits their ability to remain or expand in California and meet the needs of

⁷ Source: Energy Information Agency (EIA), EIA-861M Monthly Electric Power Industry Report, Monthly sales to ultimate customers by state and utility for all sectors (Industrial columns) January 2010 - November 2025.

1 their customers. Loss of local production capacity of these critical goods and services
2 shifts jobs, tax revenue, investment, and economic activity out of state. In addition, the
3 loss of in-state production imposes supply chain challenges, potential supply delays, and
4 logistics costs on consumers, and places upward pressure on price inflation.

5 Some CLECA members are pursuing electrification, carbon capture, and other
6 technologies to achieve individual environmental and decarbonization targets that involve
7 consuming significantly more electricity. Increasingly unaffordable electric rates will be
8 a significant barrier to CLECA members' ability to competitively achieve their individual
9 company goals, especially if competitors in other states are not subject to decarbonization
10 mandates. The current reality and risk of further economic and emissions leakage is real.

11 Many CLECA member companies are designated as EITE, with the associated
12 risk of emissions leakage. Emissions leakage occurs when emissions apparently decrease
13 within California but shift out of state and even increase globally. The Commission
14 explains, “[e]missions leakage could occur if a production facility moved out of
15 California to a jurisdiction without a Cap-and-Trade Program or other climate goals.”⁸
16 Emissions leakage can occur when an industrial facility that produces an essential good is
17 no longer able to economically justify investments to meet customer demand, or is no
18 longer able to compete in California and is forced to close its facility. To meet
19 California’s demand, that good must now be imported from an out-of-state jurisdiction
20 with less robust environmental regulations or climate goals, and shipped over longer
21 distances by truck, rail, or ship, with greater supply chain vulnerability. The loss of these

⁸ CPUC Website: California Industry Assistance (Section: “What is the purpose of the California Industry Assistance Credit?”) <https://www.cpuc.ca.gov/industries-and-topics/natural-gas/greenhouse-gas-cap-and-trade-program/california-industry-assistance>. (Cap-and-Trade is now referred to as “Cap-and-Invest”).

1 companies increases global emissions in the short term and, once lost, may not be
2 replaceable.

3 **Q WHAT IS THE PROJECTED REVENUE REQUIREMENT INCREASE**
4 **FROM THIS APPLICATION?**

5 **A** PG&E projects that its proposed revenue requirement for combined electricity and
6 natural gas will increase by 8% over authorized revenue in 2026, followed by increases
7 of 6.1% each year from 2028-2030.⁹ When isolating the electricity revenue requirement,
8 we see a sharper increase: PG&E’s proposed 2027 over 2026 adopted revenue
9 requirements for electric distribution show an 11.2% increase, a staggering 24.9%
10 increase for electric generation,^{10,11} and a 13% increase on a combined electric basis, with
11 further increases of 7% each year from 2028 to 2030.¹²

12 PG&E asserts, “This application represents a significant turning-of-the-corner and
13 shows the benefit of the various affordability initiatives underway at PG&E.”¹³ However,
14 a look at the revenue requirement increase requested in this proposal compared to recent
15 history shows the opposite: PG&E proposes the largest ever electricity revenue
16 requirement increase for a single GRC period over a prior GRC, \$11.7 billion. The
17 previous record was PG&E’s last adopted GRC, which saw a \$9.6 billion increase, again
18 larger than the previous GRC’s adopted increase of \$3.9 billion.¹⁴ See Figure 2 for

⁹ PG&E Application at pp. 1-2.

¹⁰ PG&E-10 Table 1-1: 13% combined increase from Adopted (\$991 + \$305) / 2026 Adopted (\$8,856 + 1,224).

¹¹ Where applicable, and unless otherwise noted, all references to PG&E Testimony refer to the *Errata* version of that testimony.

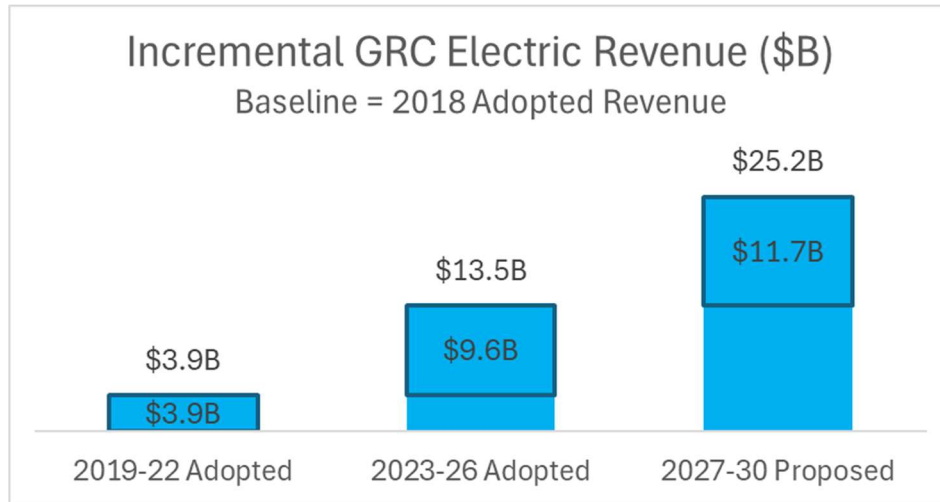
¹² CLECA Workpaper 1.1.

¹³ PG&E Application ,at p. 1.

¹⁴ See A.18-12-009 at p. 6 (Table 3 shows PG&E’s **adopted** electric (distribution + generation) revenues (\$M): 2018 (6,283) and 2019 (6,555); *Joint Motion for Approval of Settlement Agreement*, A.18-12-009, Jan. 14, 2020 at Appendix C (adopted in D.20-12-005) (showing PG&E’s **adopted** electric (distribution +

1 incremental and cumulative electric revenue requirement increases by GRC period
2 relative to the 2018 adopted revenue.

3 **Figure 2**
4 **Incremental Electric Revenue by GRC Period¹⁵**



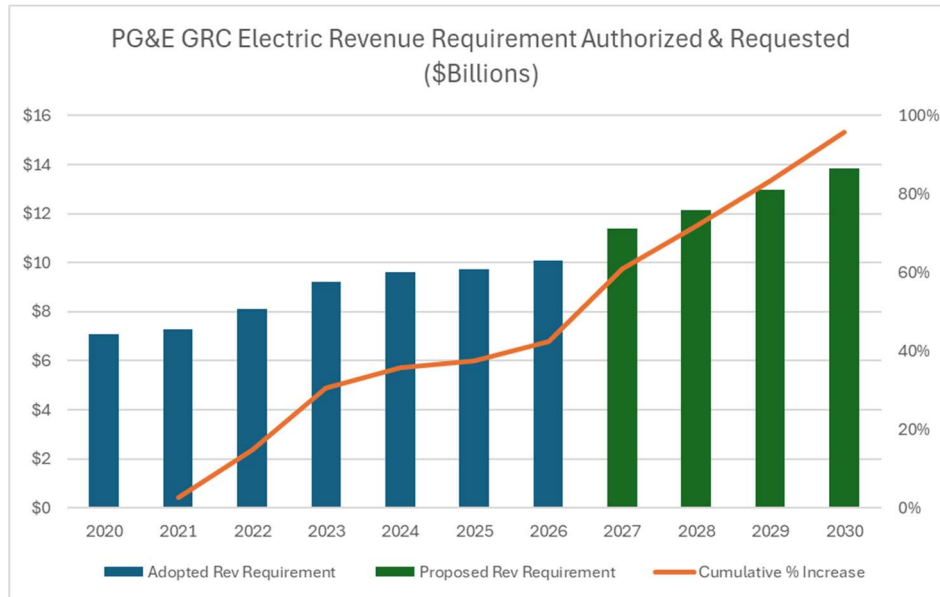
5
6 Looking at the electric revenue requirements year-by-year in Figure 3, we see an
7 increase from \$7.1 billion in 2020 to the proposed \$13.8 billion in 2030, a **96% increase**
8 **(37% since 2026)** if this application is approved.

9 **Figure 3**
10 **GRC Electric Revenue Requirement by Year since 2020¹⁶**

generation) revenues (\$M): 2020 (7,072) and 2021 (7,269); D.23-11-069 at Appendix A (Table 1 shows PG&E's **adopted** electric (distribution + generation) revenues (\$M): 2022 (8,124), 2023 (9,228), 2024 (9,594) and 2025 (9,715)); PG&E Application at 22 (Table 1 shows PG&E's **adopted** electric (distribution + generation) revenues (\$M): 2026 (10,080); PG&E Application at 23 (Table 2 shows PG&E's **proposed** electric revenues (\$M): 2027 (11,376)).

¹⁵ CLECA Workpaper 1.1.

¹⁶ CLECA Workpaper 1.1.



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These proposed revenue requirement increases are simply incompatible with electric rate affordability. Further, these increases do not include all costs that may increase rates even further, and these increases are understated by several accounting and procedural adjustments that reduce headline GRC revenue without providing real cost relief to ratepayers.

7

Q WHAT IS THE EXPECTED IMPACT OF THIS PROPOSED INCREASED REVENUE ON ELECTRIC RATES?

8

9

A PG&E provides illustrative electric rates that show sustained increases for both bundled and unbundled customers over the GRC period. By year (2027, 2028, 2029, 2030): Bundled rates show increases of 5.0%, 2.8%, 2.9%, and 3.0%;¹⁷ and unbundled rates (DA/CCA) show increases of 9.6%, 4.4%, 4.5%, and 4.6%.¹⁸

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These increases are significant, and reflect a continuation of the seemingly inexorable upward trend in PG&E's rates. While the associated rate increases are less

¹⁷ PG&E-10 at p. 18-14 (Table 18-7).

¹⁸ PG&E-10 at p. 18-14 (Table 18-8).

1 pronounced than the revenue increases, any scenario that drives further bill increases
2 during the GRC period is incompatible with critical affordability goals. Further, these
3 projected rate changes are for “illustrative” purposes, embed several uncertain
4 assumptions subject to change, and “do not consider changes in revenue requirements not
5 requested in this proceeding.”¹⁹ Thus, revenue requirement is a more reliable metric of
6 the impact of this GRC Application on affordability, with fewer uncertain assumptions
7 and exclusions.

8 **Q ARE THESE PROJECTED INCREASES MODEST?**

9 **A** No. The projected annual increases in electric revenue requirement of 7% to 13%,
10 or projected annual electric rate increases ranging from 2.8% to 5.0% for bundled
11 customers and 4.6% to 9.6% for unbundled customers, are not modest, given the
12 affordability crisis and the dramatic increases in rates that have already occurred. The
13 projected increases in percentage terms appear less significant than they really are, given
14 that PG&E’s rates are already so high. PG&E is proposing spending that results in a
15 cumulative illustrative increase of approximately \$20/MWh for bundled and unbundled
16 industrial customers from 2025 to 2030.²⁰ This would be an 18-30% increase if applied to
17 the rates of a neighboring state’s utility.²¹ The absolute increased cost of electricity
18 matters more than percentages. If an industrial customer’s electricity cost increases by
19 \$1 million per year compared to its competition out of state, it is no comfort that its rates
20 were already much higher to start with.

¹⁹ PG&E-10 at p. 18-8 (Table 18-3).

²⁰ PG&E-10 at p. 18-14 (Tables 18-7 and 18-8).

²¹ EIA data (Figure 1): 2025 rates among neighboring utilities vary from \$60 - \$110/MWh.

1 **Q WOULD PROJECTED LOAD GROWTH LOWER RATES DURING THE**
2 **GRC PERIOD?**

3 **A**PG&E provides illustrative electric rate changes assuming significant load growth
4 based on the California Energy Commission’s (CEC) 2024 Integrated Energy Policy
5 Report (IEPR). Under these growth assumptions, PG&E still projects a net increase in
6 electric rates over the GRC period: 4% increase in 2027, 0% in 2028-29, and -1% in
7 2030.²² The CEC forecast load growth is uncertain, as evidenced by the most recent 2025
8 IEPR, which projects 2030 demand in PG&E’s planning area to be 5.1% lower than it
9 was in the 2024 IEPR version used in PG&E’s load growth rate impact illustration.²³
10 Load growth may be hampered further by continued rate increases. CLECA recommends
11 that the Commission evaluate the reasonableness of this Application based on electric
12 sales forecasts vetted by stakeholders and adopted by the Commission in effect at the
13 time of filing,²⁴ and approve only a revenue requirement that results in declining electric
14 bills across the entire GRC period under reasonable and well-justified load-growth
15 scenarios.

²² PG&E-10 at p. 18-17 (Table 18-11; shows only *residential bill impact* of GRC).

²³ 2024 IEPR CEDU Baseline Forecast for PG&E projects demand of 138 GWh in 2030; 2025 IEPR CED Baseline Forecast for PG&E projects 131 GWh, representing a 5.1% reduction from 2024.

²⁴ The 2025 electric load forecast was adopted by D.24-12-038 in PG&E’s 2025 ERA Forecast proceeding.

1 **PG&E AFFORDABILITY AND PROPOSED SPENDING**

2 **Q DOES PG&E ADEQUATELY ADDRESS AFFORDABILITY IN THIS**
3 **GRC?**

4 **A** No. PG&E states its primary objective in this Application is “stabilizing bills
5 while improving service.”²⁵ Electric rates are not stable under this proposal, with
6 significant increases in revenue requirement and projected electric rates across customer
7 classes. And even if they were, stabilizing bills in the midst of an affordability crisis after
8 historic and unprecedented bill increases is glaringly inadequate. Ratepayers need bill
9 relief, not locked-in rates at historically high, unaffordable levels.

10 While PG&E makes several statements regarding its concern for affordability, the
11 materiality of its proposal features vastly increased activity levels, historically high
12 increases in electric revenue requirements, projected increases in electric rates, and a
13 negligible amount of cost savings through sustainable efficiencies.

14 PG&E boasts of its Lean Operating Model delivering \$600M in savings over the
15 GRC period, and “\$2.5 billion in savings these last 3 years into lower forecasts.”²⁶
16 However, these efforts have not translated into meaningful improvements to affordability.

17 **Q WHAT ARE SOME OTHER EXAMPLES OF PG&E’S INADEQUATE**
18 **CONSIDERATION OF AFFORDABILITY?**

19 **A** Some examples are listed below:

²⁵ PG&E Application at p. 3

²⁶ PG&E-01 at p. 1-3.

1 1. PG&E’s annual A&G Expense (removing “adjusted for capital”)²⁷ is increasing
2 from \$2.3B in 2024 to \$2.6B in 2027, with the 2027 figure excluding pension
3 contributions.²⁸ PG&E has not adequately justified this increase in overhead costs,
4 especially amidst the current affordability crisis. CLECA recommends that annual A&G
5 spending be held flat from the prior GRC.

6 2. PG&E proposes a substantial expansion of power generation capital spending and
7 headcount despite proposing no new generation capacity. PG&E attributes this increase
8 to aging infrastructure and an aging workforce, conditions that were foreseeable and
9 should have been addressed through incremental planning over multiple GRC cycles.
10 Instead, PG&E now proposes to accelerate this work into the current GRC period,
11 resulting in a doubling of capital and operating expenditures and a roughly 30 percent
12 increase in headcount.²⁹ CLECA recommends that power generation headcount be held
13 flat, and that the Commission require PG&E to make a project-by-project showing that
14 each proposed power generation activity is necessary in the current GRC period. For any
15 activity that PG&E cannot demonstrate is urgent and incapable of deferral, the
16 Commission should either reject the activity outright or approve it only on a phased basis
17 over two or more GRC cycles.

18 3. PG&E’s headcount efficiency significantly lags its peers. In a comparison of the
19 number of accounts served per employee of seven comparable large utilities with readily

²⁷ A certain portion of A&G expenses are transferred to construction via FERC Account 922 (described at PG&E-10 p. 5-5), thus reducing the stated A&G total. CLECA added these expenses back for a more holistic A&G view.

²⁸ PG&E-10 at p. 5-13 (Table 5-6: A&G expenses + A&G Capital Transfer (adjustment) \$2.3B in 2024, \$2.6B in 2027, an 11% increase).

²⁹ PG&E-5 at p. 3-27 (Power gen headcount increasing from 986 in 2024 to 1271 in 2027).

1 available data (see Table 1), PG&E came second-to-last. Normalizing PG&E’s headcount
 2 to match the peer group average would require a headcount reduction of 20%.³⁰

3 **Table 1**
 4 **Accounts per Employee of PG&E and comparable large utilities^{31, 32}**

Company	Headcount	Gas accounts (M)	Power accounts (M)	Acct per Employee
Centerpoint	8,350	3.9	2.95	820
FP&L	9,277		6	647
SDG&E	4,450	1.49	0.905	538
Duke Energy	26,000	8.6	1.7	396
SCE	13,483		5	371
PG&E	29,323	4.5	5.5	341
Con Ed	15,097	3.6	1.1	311

5
 6 Yet PG&E is not proposing reductions in overall headcount and, in fact, seeks
 7 increases in several business segments. These include power generation (as discussed
 8 earlier in this section), corporate services (increase from 886 to 915),³³ and electric
 9 distribution, where PG&E requests authorization for an additional 1,208 employees from
 10 2024 through 2030.³⁴ CLECA acknowledges that evolving priorities and expected growth
 11 in certain business areas may justify targeted headcount additions in specific departments.
 12 Nevertheless, considering the need to maintain sustainable affordability for ratepayers,
 13 the expanding capabilities of technology to support or supplant existing workflows, and
 14 PG&E’s headcount efficiency lag relative to its industry peers, CLECA urges the

³⁰ Group average accounts served per employee is 427 (Total accounts served / Total employees); PG&E’s headcount based on this average would be 10M accounts / (427 accounts / employee) = 23,424 employees, or a reduction of 20% from 29,323.

³¹ IOUs in this context: Investor-owned utility, including both California-jurisdictional IOUs and selected out-of-state investor-owned utilities used for benchmarking.

³² See CLECA Workpaper 1.3 for source data.

³³ PG&E-9 at p. 1-6 (Figure 1-2).

³⁴ PG&E-4 at p. 2-AtchB-14 (Table 2B-3).

1 Commission to apply rigorous scrutiny before approving any proposed headcount
2 increases.

3 4. PG&E proposes the construction of a new \$99 million “PG&E Academy”
4 building so that it can “continue the delivery of state-of-the-art safety training and
5 accommodate the growing number of students and courses provided.”³⁵ PG&E fails to
6 explain how this is the most efficient way to meet its needs, given the technological
7 advances that have augmented or obviated the need for many in-person trainings, and
8 given office space likely available with PG&E’s remote and hybrid work model.³⁶

9 CLECA recommends rejection of this request.

10 **Q IS PG&E’S REQUEST FOR UNDERGROUNDING “BRIDGE FUNDING”**
11 **IN THIS GRC REASONABLE?**

12 **A** No. PG&E seeks authorization for undergrounding spending of \$932 million in
13 2027 through this GRC,³⁷ while also requesting authority to continue undergrounding
14 spending of an expected \$1,212 million in 2028 and similar magnitude annual extensions
15 in subsequent attrition years through advice letter filings (not included in this GRC

³⁵ PG&E-7 at p.1-6.

³⁶ PG&E job postings describe multiple positions as “**hybrid, working from your remote office and your assigned work location,**” indicating that PG&E uses a hybrid workplace model that includes remote work. For example, a principal contract manager position and a building electrification supervisor role both use the hybrid/remote language. See PG&E job postings: “**This position is hybrid, working from your remote office and your assigned work location**” (Principal Contract Manager, Oakland), <https://jobs.pge.com/job/oakland/principal-contract-manager/29673/82144937088>; “**This position is hybrid, working from your remote office and your assigned work location on average between 0–3 days per week**” (Supervisor, Building Electrification and Efficiency Programs, Oakland), <https://jobs.pge.com/job/oakland/supervisor-building-electrification-and-efficiency-programs/29673/91572451216>.

³⁷ PG&E-4 at p. 7-32 (“PG&E is forecasting 307 miles for 2027); PG&E-4 at p. 7-33 (“The 2027 forecast unit cost of \$3.03 million per mile is less than the 2024 recorded unit cost of \$3.2 million per mile.”) 307 miles x \$3.03M/mile = \$930.2M undergrounding cost in 2027.

1 revenue requirement).³⁸ This is a potential total of over \$4.5 billion during the GRC
2 period, most of which is not sufficiently justified or explicitly included in this GRC
3 revenue requirement proposal. This request is referred to by PG&E as “bridge funding,”
4 because its purpose is to continue PG&E’s current undergrounding program during the
5 interim period between the end of the previous GRC and the beginning of their
6 anticipated approval of their pending Electric Undergrounding Program (EUP)
7 application.³⁹

8 This approach raises significant procedural and substantive concerns. It would
9 allow PG&E to obtain Commission authorization for substantial funding without
10 adequate justification in this GRC revenue request, and without the evidentiary showing
11 required in the EUP proceeding. In effect, the GRC would pre-authorize funding that is
12 intended to be reviewed in a separate rate case, while the EUP would be deprived of
13 independent significance and meaningful review. Furthermore, approval of the requested
14 bridge funding would authorize an expensive undergrounding spending program with
15 insufficient justification when other more cost-effective solutions may be available.

16 CLECA therefore recommends that the Commission reject PG&E’s request for
17 undergrounding bridge funding in this GRC, and require that any such funding be
18 proposed, justified, and evaluated in a single proceeding.

³⁸ PG&E-4 at pp. 7-53 -7-54 (“PG&E is proposing 400 underground miles for 2028 and for all subsequent years, as needed, until PG&E transitions to the EUP... PG&E’s forecast is \$1,212M in funding in 2028 at an average unit cost of \$3.03M per mile (\$2.97M plus \$55,000 per mile per transformer”); PG&E-4 at p.7-47 (While no explicit forecast for 2029 or 2030 was given, we assume 400 miles at the same cost per mile, as “[PG&E] is committed to meeting the \$2.97 million per mile [plus transformer cost] for undergrounding starting in 2027.”)

³⁹ PG&E-4 at p. 2-13.

1 **Q DOES THE REQUESTED GRC REVENUE REQUIREMENT**
2 **UNDERSTATE TOTAL RATEPAYER COSTS THROUGH**
3 **ACCOUNTING AND PROCEDURAL ADJUSTMENTS?**

4 **A Yes.** PG&E’s GRC proposal relies on a series of accounting treatments,
5 exclusions, and collection-timing changes that reduce the stated GRC revenue
6 requirement without reducing the total costs ultimately borne by ratepayers. These items,
7 shown in Table 2, do not reflect underlying efficiencies or cost savings; rather, they alter
8 where and when costs are recovered.

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Table 2
Accounting and Procedural Adjustments Impacting GRC Revenue

Adjustment implemented in GRC application	Reduction in GRC Revenue (2027-2030)
Diablo Canyon Payments ⁴⁰	\$700M
Medical Trust Repurposing ⁴¹	\$500M
Depreciation Exception ⁴²	\$546M
Generation Inspection LTSA Capitalization Policy ⁴³	\$41M
IT O&M Capitalization Policy	Unknown
Test & Treat + Pole Reinforcement Capitalization Policy	\$149M ⁴⁴ + \$38M ⁴⁵
Potter Valley Decommissioning Collection Change ⁴⁶	\$266M
11 Pending / To-Be-Filed Applications with CPUC that may impact revenue	Unknown
Total Known Impact	\$2,240M

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These adjustments do not reduce total cost to ratepayers. In some cases, costs are excluded from the GRC and recovered through other proceedings. In others, costs are deferred through capitalization or collection-timing changes, resulting in deferred recovery from future ratepayers, often with an associated additional cost due to financing

⁴⁰ PG&E-1 at p. 1-3.

⁴¹ PG&E-1 at p. 1-3.

⁴² PG&E-10 Table 8-3: \$546M "Saved" by not following the depreciation study via a one-time exception.

⁴³ PG&E-5 at p. 7-18.

⁴⁴ PG&E-4 at p. 15-1 (Table 15-22 shows Pole Test & Treat capital of \$41,398 for each GRC year. Previously recorded as expense. Total for GRC period is \$165M capital that would have been expense. Assuming a 20-year recovery period, the actual portion of this capital recovered during the GRC would be approximately \$16.5M, so the net impact of this change in policy is \$149M).

⁴⁵ PG&E-4 at p. 15-55 (Table 15-24 shows capital spending on pole reinforcement of \$10,592M per year. Previously recorded as expense. Total for GRC period is \$42M capital that would have been expense. Assuming a 20-year recovery period, the actual portion of this capital recovered during the GRC would be approximately \$4.2M, so the net impact of this change in policy is \$38M).

⁴⁶ PG&E-5 p 7-14 ("in an effort to reduce customer costs, PG&E is proposing to recover the costs for the Potter Valley project over two GRC periods (8 years).") (Table 7-2 lists the decommissioning cost estimate as \$532M; therefore the impact of spreading it over 2 GRC periods (rather than 1) would be reducing the current GRC's revenue requirement by \$266M.).

1 costs and shareholder return. As a result, PG&E's proposed revenue requirements in this
2 GRC understates the true ratepayer cost of its proposed activities.

3 CLECA urges the Commission to evaluate PG&E's revenue requirement on a
4 basis that considers the effects of these adjustments.

5 **Q WHAT IS THE INFORMATION TECHNOLOGY (IT) O&M**
6 **CAPITALIZATION POLICY CHANGE AND WHY DOES IT MATTER**
7 **FOR RATEPAYERS?**

8 **A** PG&E proposes to change its accounting treatment for IT projects by capitalizing
9 all one-time IT project expenditures that are currently treated as a mix of capital and
10 expense. PG&E characterizes this proposal as a matter of consistency and inter-
11 generational equity.⁴⁷ However, this also increases the rate base and reduces the
12 presented GRC revenue request, similar to the other capitalization policy changes listed
13 in Table 2. This is another revenue requirement adjustment that must be accounted for,
14 since it obscures the presentation of the actual GRC revenue PG&E requests to recover
15 from CLECA members and all other ratepayers.

16 However, PG&E does not disclose in its testimony the expected revenue or rate
17 impacts of this policy change. Absent such disclosure, parties and the Commission cannot
18 assess the magnitude of the effect or evaluate whether the proposal is reasonable. CLECA
19 recommends that the Commission reject this proposed capitalization of IT O&M, or, at a
20 minimum, appropriately adjust for the impact in assessing the overall GRC revenue
21 requirement and require PG&E to explicitly quantify and reflect the impacts of the
22 proposed IT capitalization policy change.

⁴⁷ PG&E-10 at p. 7-21.

1 **RISK MANAGEMENT PRIORITIZATION**

2 **Q ARE PG&E’S RISK MANAGEMENT ACTIVITY RECOMMENDATIONS**
3 **PRUDENT?**

4 **A** No. PG&E proposes 75 foundational risk management activities⁴⁸ and 252 risk
5 management programs⁴⁹ in this GRC. While foundational activities are not subject to
6 cost-benefit scoring, PG&E assigns CBRs to its risk management programs.

7 In its direct testimony, PG&E presented CBRs calculated using risk-averse
8 scaling, which inappropriately inflates estimated benefits relative to costs by 169%.⁵⁰
9 PG&E subsequently provided workpapers reporting risk-neutral CBRs for these same
10 programs.⁵¹ CLECA finds the risk-neutral CBR to be the more informative metric, as it
11 reflects expected costs and benefits without embedding unvetted policy judgments about
12 risk tolerance.

13 CLECA acknowledges that CBRs are not the only criterion for project selection,
14 and does not contend that programs with CBRs below 1 must be rejected categorically.⁵²
15 However, such programs should be the exception rather than the rule, and should require
16 clear and specific justification. But in this GRC, PG&E proposes the opposite: most of its
17 proposed programs on a risk-neutral basis have a CBR less than 1.

18 The majority of PG&E’s proposed risk management spending does not
19 demonstrate positive expected value to ratepayers on a risk-neutral basis. Of the

⁴⁸ PG&E-2 Workpaper 1-11 *Foundational Activity Allocated Spend* lists 75 activities.

⁴⁹ PG&E-2 Workpaper 1-14 *WP 1-14 GRC Mitigations and Controls and their CBRs_Errata11.10.25* lists 252 programs.

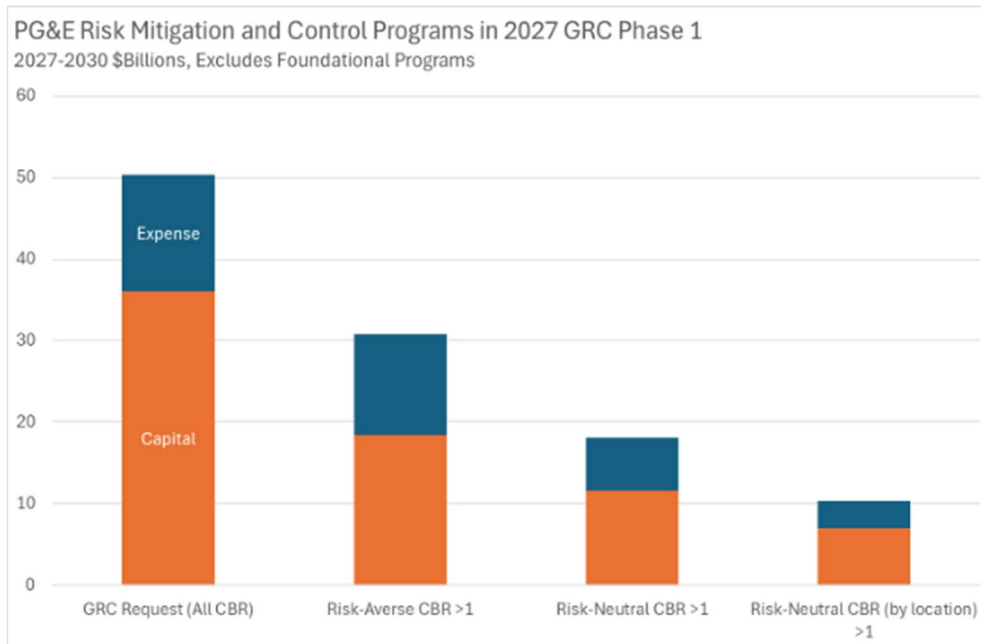
⁵⁰ Total benefit of programs in PG&E-2 workpaper 1-14 = \$467M; total benefit of (same) programs in PG&E workpaper 1-16 = \$174M; See CLECA Workpaper 1.2 for calculation.

⁵¹ PG&E-2 workpaper 1-16 *WP 1-16_CBR without risk-averse scaling function_Errata11.10.25*.

⁵² D.22-12-027, at pp. 26-27.

1 approximately \$50 billion in proposed spending, less than \$20 billion is associated with
2 programs with a CBR greater than 1 (see Figure 4). At the tranche level, only about \$10
3 billion, roughly 20 percent, of PG&E’s proposed spending on risk management programs
4 has a CBR greater than 1.

5 **Figure 4**
6 **Risk Management Programs & Tranches by CBR⁵³**



7
8 Accordingly, CLECA recommends that the Commission evaluate PG&E’s risk
9 management programs using risk-neutral CBRs as the primary analytical reference, and
10 require PG&E to prioritize its proposed spending accordingly. Tranches with risk-neutral
11 CBRs below 1 should be approved only as narrowly defined exceptions, supported by
12 explicit findings demonstrating safety necessity, legal or regulatory obligation, or clearly
13 articulated non-quantifiable benefits that cannot reasonably be captured within the CBR
14 framework.

⁵³ CLECA Workpaper 1.2.

1 **LOAD GROWTH INVESTMENT SEQUENCING & PRIORITIZATION**

2 **Q DOES PG&E’S LOAD GROWTH PROPOSAL REASONABLY**
3 **ACCOUNT FOR UNCERTAINTY IN ELECTRIFICATION ADOPTION**
4 **AND THE ROLE OF DYNAMIC PRICING?**

5 **A** No. PG&E’s load growth proposal relies on optimistic assumptions regarding
6 electric vehicle (EV) and building electrification adoption, while proposing substantial,
7 front-loaded capital investment to serve that assumed demand. The increased near-term
8 electric rate increases resulting from this approach are likely to hinder the very customer
9 adoption and investment in electrification assumed in this Application. At the same time,
10 PG&E gives insufficient consideration to the role that dynamic pricing and demand
11 response could play in moderating and shifting infrastructure needs.

12 PG&E proposes more than \$9 billion in capital spending for load growth within
13 power distribution, including approximately \$2 billion associated with plug-in electric
14 vehicles.⁵⁴ PG&E forecasts rapid EV-driven demand growth between 2024 and 2027,
15 projecting that non-residential EV demand will increase by approximately 4.5 times, and
16 residential EV demand by approximately 2.3 times over that period.⁵⁵ PG&E links these
17 forecasts directly to the need for new business and capacity investments. However, the
18 transportation electrification market and associated load growth forecasts are uncertain,
19 as the Commission recognized in reducing amounts approved for Transportation
20 Electrification Grid Readiness (TEGR) requested by Southern California Edison (SCE).⁵⁶

⁵⁴ PG&E-4 at p. 10-22 (Table 10-7).

⁵⁵ PG&E-4 at p. 2-2.

⁵⁶ D.245-09-030, *Decision on Test Year 2025 General Rate Case for Southern California Edison Company*, A.23-05-010, Sep. 23, 2026 at pp. 241-242 (recognizing uncertainty in transportation electrification load growth and authorizing a reduced Transportation Electrification Grid Readiness balancing account due to uncertain market conditions).

1 PG&E’s proposal fails to recognize that this GRC period represents a critical
2 opportunity to leverage load growth to reduce unit rates, provided that investment is
3 carefully paced and aligned with rate affordability. If rates rise too quickly or fail to
4 moderate as a result of aggressive anticipatory capital spending, electrification adoption
5 may fall short of PG&E’s projections, leaving remaining ratepayers to bear higher costs.

6 Moreover, PG&E’s proposal largely ignores the substantial demand flexibility
7 that is likely to accompany broader deployment of effective dynamic pricing and other
8 load-shaping mechanisms. The Commission continues to advance dynamic rate designs
9 and demand response frameworks, expressly recognizing that Distributed Energy
10 Resources and flexible loads can be “incentivized to operate in a manner that can ...
11 improv[e] system reliability and the efficiency of grid infrastructure use.”⁵⁷ The CEC
12 Load Management Standards (LMS) require utilities and load-serving entities to make
13 time-varying rates and related information available so customer loads can respond to
14 grid conditions. The CEC explains that these standards are designed to “align electricity
15 use with generation and grid capacity,” enabling load flexibility that “benefits customers
16 and the grid.”⁵⁸ Clearly, these tools have the potential to materially reduce peak demand,
17 mitigate grid constraints, and defer, avoid, or shift distribution infrastructure upgrades.

18 Yet PG&E’s load growth and capital forecasts do not adequately reflect this
19 potential, resulting in a proposal that overstates near-term infrastructure needs and
20 understates the role of price-based demand management. Importantly, the distribution
21 infrastructure upgrades that remain necessary after incorporating dynamic rates and

⁵⁷ D.23-04-040, *Decision Adopting Electric Rate Design Principles and Demand Flexibility Design Principles*, R.22-07-005, May 3, 2023 at p. 28.

⁵⁸ <https://www.energy.ca.gov/programs-and-topics/topics/load-flexibility/load-management-standards>.

1 demand response will likely vary by location and involve different distribution elements
2 than those proposed in this GRC.

3 CLECA recommends that the Commission require PG&E to sequence and size
4 load growth and electrification-related investments based on observed load growth and
5 realistic demand forecasts that incorporate the potential demand response from dynamic
6 pricing and other load-shaping programs.

7 **Q WHAT DOES PG&E'S PRIOR DEFERRED CAPITAL WORK INDICATE**
8 **ABOUT ITS ABILITY TO EXECUTE ITS CURRENT GRC PROPOSAL?**

9 **A** PG&E entered this proceeding with a substantial backlog of Commission-
10 authorized capital work that it failed to complete in the prior GRC cycle. The unexecuted
11 scope totals approximately \$1.9 billion from the 2023-2026 period.⁵⁹ As such, PG&E's
12 proposal to pursue an even more ambitious and speculative capital agenda is difficult to
13 reconcile with its demonstrated execution backlog, particularly given the acute
14 affordability pressures facing customers.

15 The magnitude of deferred work across successive GRC cycles risks weakening
16 accountability by decoupling Commission authorization from actual delivery. CLECA
17 therefore recommends that the Commission prioritize projects and limit approved capital
18 work in this GRC to activities that are clearly demonstrated to be necessary, high priority,
19 urgent in need, and that PG&E has demonstrated it can reasonably execute within the
20 GRC period.

⁵⁹ Deferred work value based on PG&E-2 Table 2A-1, computed as the sum over all programs of: [2023 GRC Cycle Imputed Adopted Costs (2023-2026)]/[2023 GRC Cycle Imputed Adopted Units (2023-2026)] x ([2023 GRC Cycle Imputed Adopted Units (2023-2026)] - [2023-2024 Recorded + 2025-2026 Forecast Units]).

1 **RELIANCE ON BALANCING AND MEMORANDUM ACCOUNTS**

2 **Q WHY IS PG&E’S CONTINUED RELIANCE ON, AND EXPANSION OF,**
3 **BALANCING AND MEMORANDUM ACCOUNTS THAT FUNCTION**
4 **OUTSIDE THE GRC PROBLEMATIC?**

5 **A PG&E proposes to further its reliance on an increasingly large suite of balancing**
6 **and memorandum accounts that function outside the GRC-approved revenue requirement**
7 **budget. This approach weakens the GRC, the primary tool ratepayers rely upon to hold**
8 **utilities accountable, by eroding the discipline imposed by fixed budgets across GRC**
9 **cycles. As the Commission has observed, the GRC process “is the most transparent**
10 **available process and requires the highest levels of cost justification.”⁶⁰ GRC budgets are**
11 **intended to provide utilities with a meaningful incentive to plan and prioritize projects,**
12 **provide adequate justification that the costs are just and reasonable, and manage costs**
13 **within approved budgets. Two-way balancing accounts and other off-GRC-budget**
14 **tracking mechanisms should be narrow exceptions, reserved for costs that are highly**
15 **uncertain and genuinely outside of the utility’s reasonable control. ⁶¹**

16 As such, a reasonable and prudent utility manager should, over time, reduce
17 reliance on balancing and memorandum accounts and instead incorporate reasonably
18 foreseeable costs into GRC forecasts. PG&E’s proposal moves in the opposite direction.
19 Rather than narrowing the use of such mechanisms, PG&E continues to rely on them for

⁶⁰ CPUC Response to EO N-5-24 at p. 24.

⁶¹ D.24-12-074, *DECISION ADDRESSING THE 2024 TEST YEAR GENERAL RATE CASES OF SOUTHERN CALIFORNIA GAS COMPANY AND SAN DIEGO GAS & ELECTRIC COMPANY*, A.22-05-015 et al., at p. 850 (“Based on the evidence and arguments, the Commission finds that liberal use of two-way balancing accounts, which often ensure cost recovery from ratepayers with limited reasonableness reviews, disincentivizes utilities . . . from controlling their costs through efficient operations and protecting ratepayers from future cost recoveries due to undercollection.”).

1 large and recurring categories of spending, shifting costs outside the GRC budget and
2 weakening budget discipline.

3 CLECA recommends that the Commission generally constrain the use of two-way
4 balancing and memorandum accounts to circumstances where PG&E has clearly
5 demonstrated that such costs cannot be planned for and managed within the GRC-
6 approved budget.

7 **Q WHAT ARE SOME SPECIFIC PROBLEMATIC APPLICATIONS OF**
8 **BALANCING AND MEMORANDUM ACCOUNTS?**

9 **A** Some examples are listed below.

10 1. PG&E proposes to maintain the Hydro Licensing Balancing Account and to
11 expand its scope to include risk-mitigation activities unrelated to hydro licensing,⁶²
12 increasing expected spending from less than \$100 million per year to more than \$250
13 million per year in this two-way balancing account.⁶³ What was originally a narrow
14 account tied to a specific regulatory purpose is now proposed to function as a broad cost-
15 recovery mechanism for ongoing activities that could and should be forecasted within the
16 GRC budget. CLECA recommends that the Commission reject PG&E's proposal to
17 expand the scope of the Hydro Licensing Balancing Account.

18 2. PG&E proposes to establish a new "New Business" Balancing Account, a two-
19 way balancing account through which PG&E expects to book approximately \$3.1 billion
20 in capital spending over the GRC period.⁶⁴ PG&E contends this account is necessitated
21 by the customer-driven nature of new business requests and the unpredictable pace of

⁶² PG&E-05 at p. 3-7.

⁶³ PG&E-05 Figure 3-2.

⁶⁴ PG&E-4 at p. 10-51 (Table 10-15 lines 2 and 3).

1 electrification.⁶⁵ However, unlike emergency or catastrophic response activities, New
2 Business infrastructure is forecastable and planned on an aggregate basis using historical
3 data, customer timing information, and standardized construction metrics. PG&E’s own
4 testimony demonstrates this: PG&E states that it develops its New Business forecasts
5 using multi-year historical averages to “average out any year-to-year fluctuations,”⁶⁶ and
6 relies on granular forecasting based on estimated construction hours, adjusted for
7 cancellations and customer-requested energization timing.⁶⁷ PG&E further analyzes
8 whether customers seek service within the same year, one year later, or two years later,
9 explicitly incorporating lead times into its forecast.⁶⁸ For distribution-level connections,
10 PG&E’s planned activity is based on an aggregate basis over thousands of customers,⁶⁹
11 rather than on the timing or behavior of any single customer.

12 For larger, transmission-level connections, where a smaller number of customers’
13 timing and behavior could impact PG&E activity, PG&E has a pending application for its
14 proposed Electric Rule 30 tariff. This tariff would govern line extensions and other
15 infrastructure required to serve new transmission-level load and “requir[es] new
16 transmission-level customers to provide advances and pay for actual costs incurred for
17 facilities necessary to interconnect the customer.”⁷⁰ These increased customer

⁶⁵ PG&E-4 at p. 10-49.

⁶⁶ PG&E-4 at p. 10-14.

⁶⁷ PG&E-4 at p. 10-16 (“The 2027 Base Connects forecast uses historical recorded data for customer applications by estimated construction hours, less cancellations, and adjusted by customer timing requests. PG&E developed this granular forecast based on estimated construction hours to develop a more precise cost forecast.”).

⁶⁸ PG&E-4 at p. 10-17.

⁶⁹ PG&E-4 Workpaper Table 10-26, Line 1 (Base Connects): 14,590; 16,134; 17,952; 20,106 for 2027; 2028; 2029; 2030, respectively.

⁷⁰ A.24-11-007, *Application of Pacific Gas and Electric Company (U39E) for Approval of Electric Rule No. 30 for Transmission-Level Retail Electric Service*, Nov. 21, 2024 at p. 2.

1 contributions should sufficiently reduce the uncertainty otherwise entailed in forecasting
2 for such customers. Accordingly, New Business costs can and should be reasonably
3 forecasted and budgeted in the GRC. CLECA therefore recommends that the
4 Commission reject the proposal to create the New Business Balancing Account.

5 3. PG&E proposes to continue relying on wildfire-related memorandum
6 accounts, the WMPMA⁷¹ and the FRMMA,⁷² which operate outside the GRC framework
7 and are thus not subject to GRC budget constraints. Historically, these accounts have
8 enabled PG&E to track and later seek recovery of significant wildfire costs outside of the
9 GRC process, contributing to uncontrolled increases in rates. The Legislature directly
10 responded to this concern in Senate Bill (SB) 254, which was enacted as an urgency
11 statute on September 19, 2025.⁷³ SB 254 amended Public Utilities Code Section 8386.4,
12 granting the Commission discretion over such memorandum accounts, and narrowly
13 limiting the category of recordable costs to only those that are unforeseen and
14 incremental to the activities funded in the utility's revenue requirement.⁷⁴ SB 254's
15 urgency provision found immediate statutory reform necessary "to ensure the provision
16 of reliable and affordable electricity to ratepayers," and "to protect California consumers
17 from high electricity bills."⁷⁵

18 Notably, the Commission reached a nearly identical conclusion about the
19 ratepayer harms associated with wildfire mitigation spending several months prior to SB

⁷¹ PG&E Advice Letter 5555-E, *Wildfire Mitigation Plan Memorandum Account Pursuant to Senate Bill 901 and CPUC Decision 19-05-037*, Jun. 5, 2019 (Approved Aug. 8, 2019, effective Jun. 5, 2019).

⁷² PG&E Advice Letter (AL) 5419-E, *Fire Risk Mitigation Memorandum Account Pursuant to Senate Bill 901*, Nov. 1, 2018 (Approved Mar. 12, 2019, effective Jan. 1, 2019).

⁷³ <https://legiscan.com/CA/text/SB254/id/3270463/California-2025-SB254-Chaptered.html>.

⁷⁴ Pub. Util. Code §§8386.4(a)(1)-(2) (as amended by SB 254 §54).

⁷⁵ SB 254 §75.

1 254’s passage, in its February 18, 2025 Response to Executive Order (EO) N-5-24.
2 Specifically, the Commission found that wildfire risk mitigation costs are a primary
3 driver of ratepayer bill increases, totaling approximately \$24 billion in ratepayer
4 collections between 2019 and 2024.⁷⁶ The Commission further found that reliance on
5 multiple venues for wildfire-related cost recovery, including memorandum accounts
6 operating outside the GRC, reduced transparency, complicated oversight, and led to
7 significant above-authorized spending.⁷⁷

8 Given this legislative and Commission direction, PG&E must no longer be
9 permitted to rely on memorandum accounts as a routine mechanism for financing core
10 wildfire mitigation activities. After more than five years of implementing wildfire
11 mitigation programs and maturing its risk-assessment processes, PG&E can now
12 reasonably forecast the costs of ongoing mitigation work, and must be required to include
13 those costs in its GRC revenue requirement request. SB 254 requires that GRC
14 ratemaking serve as the primary vehicle for budgeting and reviewing wildfire mitigation
15 programs, thereby restoring the transparency, cost discipline, and prospective review that
16 is essential for safeguarding ratepayer affordability.⁷⁸ Accordingly, wildfire mitigation

⁷⁶ CPUC Response to EO N-5-24 at p. 22 (“As noted above, between 2019 and 2024, IOUs collected approximately \$24 billion from ratepayers to pay for wildfire mitigation costs and insurance premiums. The WMPs have dramatically improved the way electrical utilities in California understand and reduce the risk of utility-caused wildfire. However, the cost of implementing these plans has resulted in associated wildfire mitigation-related rate pressures.”) (internal citations omitted).

⁷⁷ Id. at pp. 23-24 (“Currently, electrical utilities request wildfire mitigation funding through multiple mechanisms at the CPUC, including GRCs, memorandum accounts for the recovery of WMP costs, and, prospectively, additional applications for large electrical undergrounding plans. The multiple streams of funding for wildfire mitigation decrease transparency, complicate oversight, and reduce accountability, leading to increased rates.”).

⁷⁸ See *Energy Producers And Users Coalition And California Large Energy Consumers Association Joint Response To Amended Scoping Memo And Ruling Questions*, A.25-05-009, Feb. 6, 2026; *Response Of The Utility Reform Network To Amended Scoping Memo And Ruling’s Questions Regarding Interpretation Of Senate Bill 254 For Purposes Of Various Wildfire Mitigation Memorandum Accounts*, A.25-05-009, Feb. 6, 2026.

1 costs should be forecasted and incorporated into PG&E's GRC budget going forward,
2 and CLECA recommends that the Commission direct PG&E to close the WMPMA and
3 the FRMMA.

1
2 **ATTACHMENT A**

3 **QUALIFICATIONS OF SAM HARPER**

4 **Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

5 **A** Sam Harper. My business address is Harper Advisory LLC, 9002 Six Pines Drive,
6 Shenandoah, TX 77380.

7 **Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU**
8 **EMPLOYED?**

9 **A** I am a consultant in the field of energy markets and policy. I am employed by
10 Harper Advisory LLC.

11 **Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND WORK**
12 **EXPERIENCE.**

13 **A** I have extensive experience in energy procurement, utility regulation, ISO/RTO
14 governance, renewable energy development, and demand response. I have direct
15 experience with commercial energy arrangements, demand response, and the stakeholder
16 processes in PJM, MISO, ERCOT, CAISO, IESO, CENACE, and various unorganized
17 markets. In my current role as a consultant, I advise organizations that engage across the
18 energy supply chain, including large energy consumers for whom energy is a significant
19 percentage of their cost of production.

20 Prior to consulting, I was the Director of Energy of North American operations
21 for Gerdau, a major steel producer with significant energy requirements and active
22 demand response participation. From 2013 to 2022, I held a variety of positions for
23 Gerdau, which included Regional Energy Manager and Assistant Vice President of

1 Operations for Gerdau's subsidiary load serving entity. My responsibilities included
2 demand response operations, RTO/ISO stakeholder process, utility regulatory
3 intervention, commercial energy contract negotiations, commodity risk management, and
4 renewable energy development.

5 I was elected each year from 2016 through 2021 to the Board of Directors of the
6 Electric Reliability Council of Texas (ERCOT). I served on the Human Resources and
7 Governance Committee throughout my tenure, and in 2021 was elected Vice-Chair. I
8 served during the Storm Uri reliability crisis in February 2021 and its aftermath.

9 I served on the Advisory Board for the Renewable Development Fund of
10 Minnesota from 2017 to 2020, ensuring renewable energy grants were awarded and
11 executed prudently and consistent with state policy goals.

12 From 2008 to 2013, I was employed by ArcelorMittal, a global steel producer,
13 ending as the Sourcing Manager of Electricity for US Operations. During that time, I
14 created and managed a load serving entity and curtailment service provider in the PJM
15 territory.

16 I earned a Bachelor of Science degree in Business Administration from the University of
17 Illinois at Urbana-Champaign in 2008, graduating with Honors.

18 **Q WHAT TESTIMONY ARE YOU SPONSORING IN THIS PROCEEDING?**

19 **A** I am jointly sponsoring the Opening Testimony of Sam Harper and John Holler
20 on Behalf of the California Large Energy Consumers Association.

21 **Q WAS THIS MATERIAL PREPARED BY YOU OR UNDER YOUR**
22 **SUPERVISION?**

23 **A** Yes, it was.

1 **CERTIFICATION**

2 I, Sam Harper, hereby certify, pursuant to Rule 13.7(e) of the Rules of Practice and
3 Procedure of the CPUC, under penalty of perjury under the laws of the State of California, that
4 the foregoing is true and correct to the best of my knowledge, and that this Certification was
5 executed on this 13th day of February, 2026 at Tervuren, Belgium.

6
7 By: 

8 Name: Sam Harper

9 Title: Consultant to the California Large Energy Consumers Association

1 **ATTACHMENT B**

2 **QUALIFICATIONS OF JOHN HOLLER**

3 **Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

4 **A** John Holler. My business address is Harper Advisory LLC, 9002 Six Pines Drive,
5 Shenandoah, TX 77380.

6 **Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU**
7 **EMPLOYED?**

8 **A** I am a financial analyst in the field of energy markets and policy. I am employed
9 by Harper Advisory LLC.

10 **Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND WORK**
11 **EXPERIENCE.**

12 **A** I have professional experience in energy-sector commercial analysis, negotiations,
13 and financial modeling. In my current role as a financial analyst, I advise organizations
14 that operate across the energy supply chain, including large energy consumers for whom
15 energy costs represent a material component of total production costs. My work includes
16 analysis of energy procurement strategies, evaluation of utility rate impacts, and financial
17 assessment of energy-related investments and regulatory proposals.

18 Prior to joining Harper Advisory, I worked as a financial analyst, advising small-
19 and medium-sized businesses on financial management, performance analysis, and cash
20 flow planning.

21 From 2009 through 2014, I was employed by ExxonMobil in its Gas & Power
22 Marketing organization, where I held a series of commercial and analytical roles. These
23 included U.S. Gas Supply Planner, Global LNG Advisor, and Commercial Advisor for

1 RasGas, a joint venture between ExxonMobil and the State of Qatar. In these roles, I was
2 responsible for commercial analysis, supply planning, contract evaluation, and support of
3 gas and power marketing activities in both domestic and international markets.

4 I earned a Bachelor of Science degree in Industrial & Systems Engineering from the
5 University of Florida in 2007, graduating *summa cum laude*, and a Master of Business
6 Administration from the University of Florida in 2009, graduating with honors.

7 **Q WHAT TESTIMONY ARE YOU SPONSORING IN THIS PROCEEDING?**

8 **A** I am jointly sponsoring the Opening Testimony of Sam Harper and John Holler
9 on Behalf of the California Large Energy Consumers Association

10 **Q WAS THIS MATERIAL PREPARED BY YOU OR UNDER YOUR**
11 **SUPERVISION?**

12 **A** Yes, it was.

13 **Q INsofar AS THIS MATERIAL IS FACTUAL IN NATURE, DO YOU**
14 **BELIEVE IT TO BE CORRECT?**

15 **A** Yes, I do.

16 **Q INsofar AS THIS MATERIAL IS IN THE NATURE OF**
17 **PROFESSIONAL OPINION OR JUDGMENT, DOES IT REPRESENT**
18 **YOUR BEST PROFESSIONAL OPINION OR JUDGEMENT?**

19 **A** Yes, it does.

20 **Q DO YOU ADOPT THIS TESTIMONY AS YOUR SWORN TESTIMONY**
21 **IN THESE CONSOLIDATED PROCEEDINGS?**

22 **A** Yes.

23 **Q DOES THIS CONCLUDE YOUR TESTIMONY?**

24 **A** Yes.

1 **CERTIFICATION**

2 I, John Holler, hereby certify, pursuant to Rule 13.7(e) of the Rules of Practice and
3 Procedure of the CPUC, under penalty of perjury under the laws of the State of California, that
4 the foregoing is true and correct to the best of my knowledge, and that this Certification was
5 executed on this 13th day of February, 2026 at Hixson, Tennessee.

6
7 By:  _____

8 Name: John Holler

9 Title: Financial Analyst for the California Large Energy Consumers Association

ATTACHMENT C

CLECA WP 1.1: Revenue Requirement

Source Data

Current GRC:

Application, Table 1 (p. 22)

Category	2026 Adopted (Millions \$)	2027 Proposed (Millions \$)	Difference from Adopted
Electric Distribution	8,856	9,847	991
Gas Distribution	3,115	3,061	-54
Electric Generation ¹	1,224	1,529	305
Gas Transmission & Storage	2,205	2,200	-5
Total General Rate Case	15,400	16,637	1,237

Application, Table 2 (p. 23)

	Gas Distribution (Millions \$)	Electric Distribution (Millions \$)	Gas Transmission & Storage (Millions \$)	Electric Generation (Millions \$)	Total (Millions \$)
2028	3,221	10,605	2,284	1,542	17,652
2029	3,389	11,373	2,371	1,592	18,725
2030	3,560	12,187	2,465	1,657	19,869

Previous GRC's

Source:	2020-22 Application (Table 3)		2020-22 Settlement (see amounts in Appendix C)			2023-2026 Decision Appendix A - See table 1				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	
Gas Distribution	1889	1963	2020	2142	2401	2588	2695	2837	3004	
Electric Distribution	4182	4364	4775	4986	5641	6934	7331	7866	8444	
Gas Transmission & Storage						1705	1948	2045	2147	
Energy Supply	2101	2191	2297	2283	2483	2294	2263	1849	1206	
Total	8172	8518	9092	9411	10525	13521	14237	14597	14801	

CLECA WP 1.1: Revenue Requirement

Analysis / Visuals

Summary Table		\$ figures in \$Millions												
Source	Year	Period	Gas Distribution	Electric Distribution	Gas T&S	Electric Generation	Total	Electric Rev Requirement	YoY %	Cumulative % Inc. since 2020	Since 2026	Incremental to 2018	Adopted Rev Requirement	Proposed Rev Requirement
2020-22 GRC Application	2018		\$1,889	\$4,182	\$0	\$2,101	\$8,172	\$6,283					\$6,283	
2020-22 GRC Application	2019	2019-22 Adopted	\$1,963	\$4,364	\$0	\$2,191	\$8,518	\$6,555	4%			\$272	\$6,555	
2020-22 GRC Settlement	2020	2019-22 Adopted	\$2,020	\$4,775	\$0	\$2,297	\$9,092	\$7,072	8%			\$789	\$7,072	
2020-22 GRC Settlement	2021	2019-22 Adopted	\$2,142	\$4,986	\$0	\$2,283	\$9,411	\$7,269	3%	3%		\$986	\$7,269	
2023-26 GRC Ruling	2022	2019-22 Adopted	\$2,401	\$5,641	\$0	\$2,483	\$10,525	\$8,124	12%	15%		\$1,841	\$8,124	
2023-26 GRC Ruling	2023	2023-26 Adopted	\$2,588	\$6,934	\$1,705	\$2,294	\$13,521	\$9,228	14%	30%		\$2,945	\$9,228	
2023-26 GRC Ruling	2024	2023-26 Adopted	\$2,695	\$7,331	\$1,948	\$2,263	\$14,237	\$9,594	4%	36%		\$3,311	\$9,594	
2023-26 GRC Ruling	2025	2023-26 Adopted	\$2,837	\$7,866	\$2,045	\$1,849	\$14,597	\$9,715	1%	37%		\$3,432	\$9,715	
2027-30 Application	2026	2023-26 Adopted	\$3,115	\$8,856	\$2,205	\$1,224	\$15,400	\$10,080	4%	43%		\$3,797	\$10,080	
2027-30 Application	2027	2027-30 Proposed	\$3,061	\$9,847	\$2,200	\$1,529	\$16,637	\$11,376	13%	61%		\$5,093		\$11,376
2027-30 Application	2028	2027-30 Proposed	\$3,221	\$10,605	\$2,284	\$1,542	\$17,652	\$12,147	7%	72%		\$5,864		\$12,147
2027-30 Application	2029	2027-30 Proposed	\$3,389	\$11,373	\$2,371	\$1,592	\$18,725	\$12,965	7%	83%		\$6,682		\$12,965
2027-30 Application	2030	2027-30 Proposed	\$3,560	\$12,187	\$2,465	\$1,657	\$19,869	\$13,844	7%	96%	37%	\$7,561		\$13,844

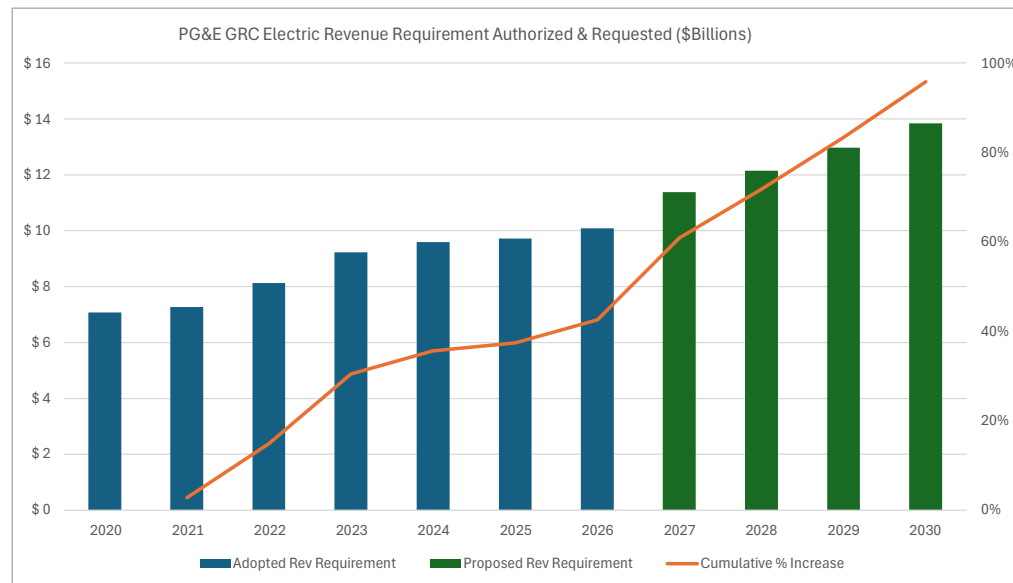
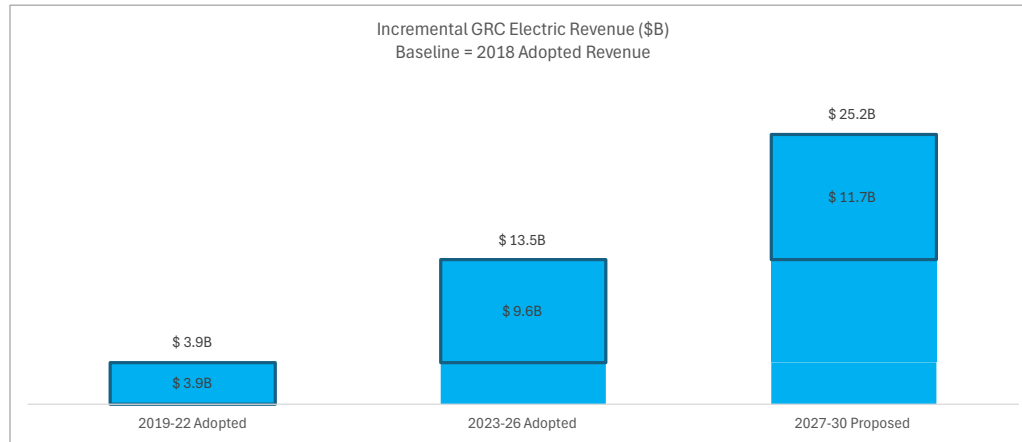
^^ Referenced in testimony

Chart - Incremental Revenue

Period	Incremental to 2018	2019-22 Addition	2023-26 Addition	2027-30 Addition	Total
2019-22 Adopted	\$3.9B	\$3.9B			\$3.9B
2023-26 Adopted	\$13.5B	\$3.9B	\$9.6B		\$13.5B
2027-30 Proposed	\$25.2B	\$3.9B	\$9.6B	\$11.7B	\$25.2B

CLECA WP 1.1: Revenue Requirement

Charts



CLECA WP 1.2: CBR Summary (used for chart)

Based on Exhibit 2 Errata Workpapers 1-14 and 1-16

	Total Expense				Capital			
	2027	2028	2029	2030	2027	2028	2029	2030
Program-Level								
All	3.27	3.66	3.69	3.75	10.22	7.97	8.38	9.40
Risk-Averse >1	2.68	3.17	3.19	3.25	5.93	3.64	3.84	5.04
Risk-Neutral >1	1.21	1.73	1.76	1.83	4.71	2.03	2.21	2.65
Tranche-Level								
All	3.71	3.99	4.02	4.09	10.14	7.93	8.25	9.09
Risk-Averse >1	2.92	3.40	3.43	3.49	6.05	3.75	3.96	5.16
Risk-Neutral >1	0.76	0.86	0.86	0.83	1.99	1.51	1.61	1.91

Chart 1

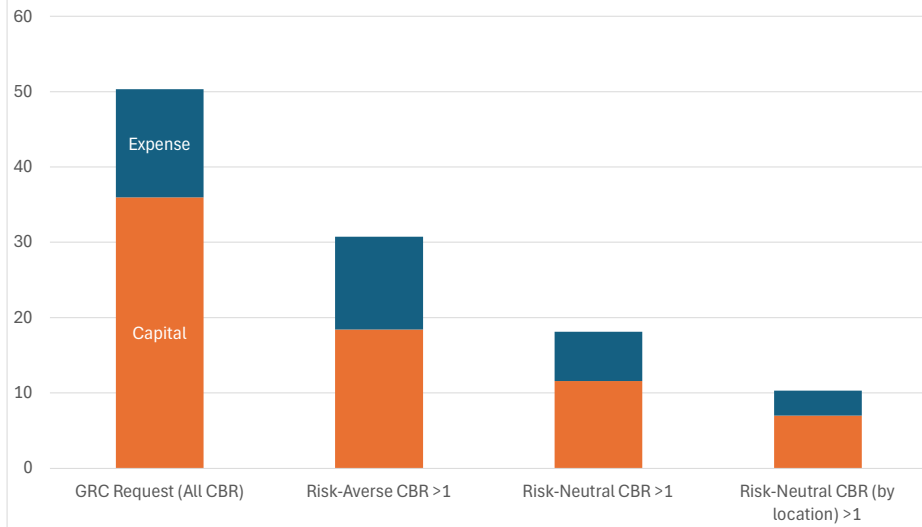
PG&E Risk Mitigation and Control Programs - 2027 GRC				
	GRC Request (All CBR)	Risk-Averse CBR >1	Risk-Neutral CBR >1	Risk-Neutral CBR (by location) >1
2027-2030 \$B				
Expense	14.4	12.3	6.5	3.3
Capital	36.0	18.4	11.6	7.0

Program / Implementation Count

	GRC Request (All CBR)	Risk-Averse CBR >1	Risk-Neutral CBR >1
# Programs	252	147	112
# Tranches	3737	1974	1027

	Risk Averse	Risk Neutral	Multiplier	% Inflation
Total Benefit (\$M)	\$466 592	\$173 758	2.7	169%
Total Cost (\$M) (incl FA)	\$52 496	\$52 496	1.0	0%
Avg CBR	8.89	3.31	2.7	169%

PG&E Risk Mitigation and Control Programs in 2027 GRC Phase 1
2027-2030 \$Billions, Excludes Foundational Programs



CLECA WP 1.3: Headcount benchmarking

Sources

Sources - Headcount

Company	Headcount	as of	Source	Context
Centerpoint	8,350	Website accessed 2/9/2026	Where We Serve	"More than 8300 employees"
FP&L	9,277	2025 (referred to in current rate case)	Florida PSC Rate Case 20250011 - Buttress Direct Testimony	Forecasted headcounts for 2027 = 9427, this is an increase of approximately 150 employees over the 2025 headcount
SDG&E	4,450	Website accessed 2/9/2026	About Us San Diego Gas & Electric	More than 4400 employees
Duke Energy	26,000	Website accessed 2/9/2026	duke-energy-fast-facts.pdf	
SCE	13,483	December 31, 2024	Edison 10-K for 2024	At December 31, 2024, Edison International had an aggregate of 14,013 employees (excluding interns)
PG&E	29,323	December 31, 2024	GRC Application - Ex 8 Table 1-3	
Con Ed	15,097	December 31, 2024	10-K for 2024	15,097 employees in the US on Dec 31, 2024

Sources - Power Accounts

Company	Power Account	as of	Source
Centerpoint	2.95	Website accessed 2/9/2026	Where We Serve
FP&L	6	Website accessed 2/9/2026	FPL Company Profile
SDG&E	0.905	Website accessed 2/9/2026	About Us San Diego Gas & Electric
Duke Energy	1.7	Website accessed 2/9/2026	duke-energy-fast-facts.pdf
SCE	5	Website accessed 2/9/2026	About SCE - Southern California Edison
PG&E	5.5	Website accessed 2/9/2026	Company Profile PG&E
Con Ed	1.1	Website accessed 2/9/2026	Corporate Facts Con Edison

Sources - Gas Accounts

Company	Gas Account	as of	Source
Centerpoint	3.9	Website accessed 2/9/2026	Where We Serve
FP&L			
SDG&E	1.49	Website accessed 2/9/2026	About Us San Diego Gas & Electric
Duke Energy	8.6	Website accessed 2/9/2026	duke-energy-fast-facts.pdf
SCE			
PG&E	4.5	Website accessed 2/9/2026	Company Profile PG&E
Con Ed	3.6	Website accessed 2/9/2026	Corporate Facts Con Edison

Table / Analysis

Company	Headcount (yr end 2024)	Gas accounts (M)	Power accounts (M)	Acct per Employee
Centerpoint	8,350	3.9	2.95	820
FP&L	9,277	0	6	647
SDG&E	4,450	1.49	0.905	538
Duke Energy	26,000	8.6	1.7	396
SCE	13,483	0	5	371
PG&E	29,323	4.5	5.5	341
Con Ed	15,097	3.6	1.1	311

Weighted avg	427
PG&E Normalized	23,424
Reduction	20%

CLECA WP 1.4: Deferred Work Calculation

From Ex 2 Chapter 2A

blue columns added

Col	A	B	C	D	E	F	G	H	I		
Source	Ex 2 Ch. 2A	Ex 2 Ch. 2A	Ex 2 Ch. 2A	Ex 2 Ch. 2A	Ex 2 Ch. 2A	Ex 2 Ch. 2A	Ex 2 Ch. 2A	D / C	C - E	G x H	
Line No	Exhibit / Chapter	Program (MAT)	Imputed Units (2023-26)	Imputed units (# only)	Imputed Cost (\$000)	Recorded + Forecast Units	Forecasted units (# only)	Recorded + Forecast Cost (\$000)	Imputed unit cost (\$000/unit)	Deferred Units	Deferred cost
1	3 Ch4	Gas Pipeline Replacement (14A)	515,328 ft	515328	416 928	358,970 ft	358970	373 151	0.81	156 358	\$126 502
2	3 Ch4	Gas Plastic Pipe Replacement (14D)	2,935,680 ft	2935680	1 658 736	2,123,269 ft	2123269	1 612 994	0.57	812 411	\$459 033
3	3 Ch4	Reliability Main Replacement (50A)	316,800 ft	316800	211 789	217,925 ft	217925	186 983	0.67	98 875	\$66 100
4	3 Ch4	New Valve Program (50R)	400 valves	400	23 501	260 valves	260	21 924	58.75	140	\$8 225
5	3 Ch4	Cross Bore Program (JQK)	77,252 insp	77252	55 679	40,940 insp	40940	57 494	0.72	36 312	\$26 172
6	3 Ch5	Valve Automation (75I)	72 valves	72	92 605	29 valves	29	39 441	1 286.18	43	\$55 306
7	3 Ch5	Fault Crossings (75L)	32 projects	32	53 120	7 projects	7	31 000	1 660.00	25	\$41 500
8	3 Ch5	Shallow Pipe (75M)	16 projects	16	39 926	7 projects	7	6 371	2 495.38	9	\$22 458
9	3 Ch5	Exposed Pipe (75T)	16 projects	16	39 926	5 projects	5	28 728	2 495.38	11	\$27 449
10	3 Ch5	Gas Gathering (84D)	44 meters	44	48 211	23 meters	23	31 553	1 095.70	21	\$23 010
11	3 Ch5	ILI Upgrades (98C)	16 projects	16	239 832	14 projects	14	450 417	14 989.50	2	\$29 979
12	3 Ch5	Casings Mitigation (3K5)	44 projects	44	57 930	40 projects	40	90 041	1 316.59	4	\$5 266
13	3 Ch5	Close Interval Survey (GJE)	1,804 units	1804	16 916	679 units	679	7 817	9.38	1 125	\$10 549
14	3 Ch5	Casings - Expense (GJM)	4,724 units	4724	17 466	3,932 units	3932	10 834	3.70	792	\$2 928
15	3 Ch5	Shallow & Exposed Pipe - Exp (JT4)	16 projects	16	11 264	3 projects	3	2 342	704.00	13	\$9 152
16	3 Ch6	GD Regulator Station Rebuild (50C)	100 stations	100	202 985	58 stations	58	151 125	2 029.85	42	\$85 254
17	3 Ch6	GD Regulator Component Repl (50L)	600 comps	600	43 412	395 comps	395	42 080	72.35	205	\$14 832
18	3 Ch6	Physical Security (76Z)	8 stations	8	37 871	5 stations	5	18 413	4 733.88	3	\$14 202
19	3 Ch8	Casings (50Q)	40 casings	40	10 980	35 casings	35	12 042	274.50	5	\$1 373
20	3 Ch8	Install Casing Test Stations (DGG)	560 stations	560	13 431	202 stations	202	10 325	23.98	358	\$8 586
21	3 Ch8	Casing Short Mitigation <100ft (DGH)	132 casings	132	17 621	53 casings	53	7 258	133.49	79	\$10 546
22	3 Ch8	Leak Survey Meter Repair (FIS)	320,000 meters	320000	39 845	241,336 meters	241336	41 006	0.12	78 664	\$9 795
23	3 Ch9	Gas Capacity - Mains (47B)	184,800 ft	184800	145 507	39,355 ft	39355	46 850	0.79	145 445	\$114 520
24	3 Ch9	Gas Capacity - Reg Stations (47C)	12 stations	12	23 933	7 stations	7	9 713	1 994.42	5	\$9 972
25	3 Ch9	Gas Capacity - Reg Comp (47D)	16 comps	16	523	15 comps	15	849	32.69	1	\$33
26	3 Ch9	GD SCADA ERX Pressure (4AF)	40 ERX	40	2 159	23 ERX	23	2 730	53.98	17	\$918
27	3 Ch9	GT SCADA Visibility (76M)	32 RTUs	32	12 184	18 RTUs	18	9 098	380.75	14	\$5 331
28	4 Ch14	UG Manhole Inspection (BFF)	6,184 manholes	6184	2 040	3,047 manholes	3047	1 722	0.33	3 137	\$1 035
29	4 Ch14	OH Equipment Test (BFG)	102,305 units	102305	10 683	76,987 units	76987	11 241	0.10	25 318	\$2 644
30	4 Ch15	Pole Test & Treat (GAA)	1,039,331 poles	1039331	86 456	196,397 poles	196397	42 131	0.08	842 934	\$70 119
31	4 Ch15	Pole Analyze Loading (GAC)	800,000 poles	800000	90 607	244,846 poles	244846	51 354	0.11	555 154	\$62 876
32	4 Ch16	UG Cable Other Replacement (56A)	70 miles	70	162 355	38 miles	38	83 731	2 319.36	32	\$74 219
33	4 Ch16	Network Cable Replacement (56N)	227,557 ft	227557	135 552	0 ft	0	644	0.60	227 557	\$135 552
34	4 Ch16	Replace Obsolete UG Switches (56S)	308 switches	308	35 672	166 switches	166	32 679	115.82	142	\$16 446
35	4 Ch16	Install Temp Indicator (56T)	9,176 units	9176	37 204	4,900 units	4900	19 875	4.05	4 276	\$17 337
36	4 Ch17	Replace Deteriorated OH Conductor (08J)	295 miles	295	188 965	39 miles	39	23 313	640.56	256	\$163 983
37	4 Ch17	OH Fuses Install/Replace (49C)	515 fuses	515	6 849	260 fuses	260	7 125	13.30	255	\$3 391
38	4 Ch17	FLISR Systems (49S)	48 activations	48	16 341	7 activations	7	3 131	340.44	41	\$13 958
39	4 Ch18	Replace Dist Substation Breakers (48D)	160 breakers	160	125 423	16 breakers	16	16 805	783.89	144	\$112 881
40	4 Ch18	Substation Animal Abatement (48X)	68 locations	68	25 292	2 locations	2	211	371.94	66	\$24 548

← Total

\$1 887 980

CLECA WP 1.5: Decarbonization Targets

Purpose: This section documents publicly available evidence that many CLECA member companies have adopted decarbonization targets and are pursuing electrification, hydrogen (electrolysis), and/or carbon capture strategies that materially increase electricity consumption.

Air Products and Chemicals, Inc.

· [Clean hydrogen and electrolysis projects; net-zero commitment. Source: https://www.airproducts.com/company/sustainability](https://www.airproducts.com/company/sustainability)

Linde Inc.

· [Sustainable development report detailing hydrogen and carbon capture investments. Source: https://www.linde.com/sustainability](https://www.linde.com/sustainability)

Messer North America, Inc.

· [Green hydrogen and carbon capture initiatives \(ZeCarb platform\). Source: https://zecarb.messergroup.com/](https://zecarb.messergroup.com/)

CalPortland Company

· [DOE-supported carbon capture research project announcement. Source: https://www.calportland.com/calportland-decarbonization-research-project-selected-for-u-s-department-of-energy-award/](https://www.calportland.com/calportland-decarbonization-research-project-selected-for-u-s-department-of-energy-award/)

CEMEX

· [Future in Action roadmap including carbon capture. Source: https://www.cemex.com/en/sustainability/future-in-action](https://www.cemex.com/en/sustainability/future-in-action)

National Cement Company

· [Lebec Net-Zero Project \(carbon capture\). Source: https://www.nationalcement.com/news-main/lebec-net-zero-project](https://www.nationalcement.com/news-main/lebec-net-zero-project)

California Steel Industries, Inc. (Nucor)

· [Net-zero by 2050 target and decarbonization strategy. Source: https://nucor.com/news-release/nucor-sets-net-zero-science-based-greenhouse-gas-targets-for-2050-122870](https://nucor.com/news-release/nucor-sets-net-zero-science-based-greenhouse-gas-targets-for-2050-122870)

Pacific Steel Group

· [EAF micro-mill project and low-emissions steel production. Source: https://pacificsteelgroup.com/mojave-micro-mill/](https://pacificsteelgroup.com/mojave-micro-mill/)

Kinder Morgan

· [Sustainability report detailing electrification of compression. Source: https://www.kindermorgan.com/WWWKM/media/Safety-Environmental/documents/2024_Sustainability_Report.pdf](https://www.kindermorgan.com/WWWKM/media/Safety-Environmental/documents/2024_Sustainability_Report.pdf)

CLECA WP 1.6: CLECA Competition

Purpose: This workpaper documents evidence that California facilities in industries represented by CLECA including steel, cement, industrial gases, and mining/minerals compete with physical production facilities located in neighboring western states.

1. Steel – Rebar / Long Products / Structural Steel Competition

· [Commercial Metals Company \(CMC\) Micro-Mill – Mesa, Arizona: Built to efficiently serve West Coast rebar and merchant bar demand.](#)

· [Nucor Steel Seattle – Auburn, Washington: Produces steel products including rebar and structural steel for regional construction markets.](#)

· [Nucor Bar Mill – Kingman, Arizona: Expanded melt shop capacity to meet Western-region demand for steel bar products.](#)

· [Nucor’s Plymouth \(UT\) facility is a non-integrated steel mill \(SIC Code 3312\) which produces approximately one million tons of structural steel products annually.](#)

Relevance: These steel facilities in Arizona, Utah, and Washington explicitly serve Western or West Coast markets, including California construction demand. Accordingly, California-based steel producers compete directly with production capacity located in neighboring western states.

2. Cement – Regional Production Serving Western Markets

· [Nevada Cement Company – Fernley, Nevada: Supplies infrastructure projects across the western United States. Source: <https://www.nevadacement.com/about/>](#)

· [Drake Cement – Paulden, Arizona: Southwest cement producer serving regional construction markets. Source: <https://www.martin-eng.com.br/sites/default/files/downloadable-files/success-storydrake-cement/drake-cement-success-story-new.pdf>](#)

Relevance: Cement plants in Nevada and Arizona serve the same regional construction and infrastructure markets as California cement producers.

3. Industrial Gases – Regional Production and Distribution

· [Linde – Western U.S. hydrogen and air separation facilities. Source: \[https://stores.lindedirect.com/wa/Air Liquide’s \\\$250M hydrogen plant located in North Las Vegas, Nevada, officially began its operations in early 2022.\]\(https://stores.lindedirect.com/wa/AirLiquide's%20\$250M%20hydrogen%20plant%20located%20in%20North%20Las%20Vegas%20Nevada%20officially%20began%20its%20operations%20in%20early%202022\)](#)

Relevance: Industrial gases (oxygen, nitrogen, hydrogen, CO2) are distributed within regional radii, meaning facilities in Arizona and Nevada compete with California plants.

4. Mining / Industrial Minerals – Regional Supply

· [U.S. Lime – Operations in Arizona and Nevada supplying lime for cement and other industries. Source: <https://uslm.com/>](#)

· [Nevada Mining Industry Overview – State mineral production serving western markets. Source: <https://minerals.nv.gov/>](#)

Relevance: Lime, limestone, and mineral inputs are produced in neighboring states and supplied into western industrial markets, including California.