

Docket No: A.25-05-009

Exhibit: _____

Date: April 23, 2026

Witness: Meredith Alexander

**ERRATA TO REBUTTAL TESTIMONY OF
MEREDITH ALEXANDER ON BEHALF OF
CALIFORNIA COALITION OF LARGE ENERGY USERS**



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1 **I. INTRODUCTION**

2 **Q.** Please state your name, affiliation and business address.

3 **A.** My name is Meredith Alexander, and I am the Principal Consultant for the California
4 Coalition of Large Energy Users (CLEU). CLEU’s business address is 901 H St., Suite 120
5 PMB 176 Sacramento, CA 95814.

6 **Q.** Please briefly describe CLEU.

7 **A.** CLEU was recently incorporated as a 501(c)(6) non-profit. to represent the interests of large
8 commercial and institutional energy consumers and ratepayers across California– including
9 Genentech, Kaiser Permanente, Microsoft Corporation and the University of California (UC).
10 Together, these organizations represent a significant proportion of the state’s non-residential
11 electricity usage, and each of these organizations has its own robust clean energy and distributed
12 resource procurement goals. One of our members, UC, is also an energy service provider (ESP).
13 CLEU was formed to advocate for policies that enhance grid reliability, improve resource
14 planning, support clean on-site generation, streamline utility processes, and promote regional
15 cooperation. Our objective is to ensure that California’s large energy users have access to stable,
16 cost-effective electricity, minimizing rate impacts while still achieving ambitious zero-emission
17 goals.

18 **Q.** Please identify yourself, your organization, and your role within your organization.

19 **A.** Meredith Alexander, Principal, Gridwell Consulting. I am the Principal Consultant to CLEU
20 and serve in the capacity as CLEU’s Acting Executive Director.

21 **Q.** Please state your relevant educational and professional background.

22 **A.** I hold a Juris Doctor and Certificate in Natural Resources Law from the Northwestern
23 School of Law at Lewis & Clark College and graduated Magna Cum Laude with Honors in
24 Environmental Policy and Political Science from Tulane University. My professional experience
25 includes serving as a law clerk on rate cases at the Bonneville Power Administration, three years
26 as a Senior Regulatory Analyst at the California Public Utilities Commission, where I focused on
27 long-term planning, California Independent System Operator (CAISO) issues, and resource
28 adequacy, and participation in rate cases across multiple states as Director for State Policy at

1 CALSTART. I have been a consultant, advising clients on electricity policy since 2022. I have
2 been the Principal Policy Consultant and Acting Executive Director of CLEU since July, 2025.
3 Since this time I have developed an in depth understanding of the magnitude and type of
4 electricity costs paid by CLEU’s members in California, their active energization requests and
5 the confidential details of various projects under development. In my time as a consultant I have
6 focused on grid reliability and done extensive research on the causes of recent grid outages and
7 disturbances. I have also studied the negative effects that both bulk and distribution grid outages
8 have on California’s businesses, institutions and all ratepayers. My complete Statement of
9 Qualifications is included at the end of my testimony.

10 **Q.** Have you prepared and reviewed this Rebuttal Testimony?

11 **A.** Yes I have personally prepared and reviewed this rebuttal testimony.

12 **Q.** Please describe the purpose of your rebuttal testimony.

13 **A.** The purpose of my rebuttal testimony is to respond to the testimony of other parties through
14 the lens of large commercial customers, and in general to provide meaningful and thoughtful
15 analysis of the recommendations of other parties, as well as the criticisms of Pacific Gas and
16 Electric’s (PG&E) proposed revenue requirements made in the testimony of other parties.

17 **II. SUMMARY OF RECOMMENDATIONS**

18 **Rate Increases and Scrutiny of the Overall Revenue Requirement**

- 19 • The Commission should evaluate PG&E's Application overall to determine whether
20 resulting rates would be just and reasonable, as is suggested by the Environmental
21 Defense Fund (EDF). The Commission should aim for meaningful and sustained
22 electricity rate reductions, as recommended by California Large Energy Consumers
23 Association (CLECA).
24 • The Commission should adopt the California Public Advocates Office (Cal Advocates')
25 CPI-based attrition rate over PG&E's proposed 6% annual attrition.

26 **Base Costs and Base Revenue (Including Diablo Canyon)**

- 27 • The Commission should immediately remove thirteen non-operational hydropower
28 facilities from the Electric Generation revenue requirement, recover remaining netbook
29 value (~\$45.2M) as a regulatory asset with no return, and make ratepayers whole for
30 returns previously collected in error, as recommended by California Community Choice
31 Association (CalCCA).

- 1 • As asserted by the Utility Reform Network (TURN), all of the costs that ratepayers will
2 bear during the 2027 General Rate Case (GRC) cycle — including \$4.12 billion for
3 Diablo Canyon — must be visible to the Commission and subject to scrutiny in this
4 proceeding.
- 5 • The Commission should direct the \$712 million Diablo Canyon Variable Performance
6 Fee toward offsetting Resource Adequacy or energy market costs, as recommended by
7 the Energy Producers and Users Coalition (EPUC), consistent with the statutory purpose
8 of the plant's extension.

9 **Depreciation of Existing Assets**

- 10 • The Commission should require that PG&E correct overcharges for hydropower asset
11 depreciation, as attested by CalCCA, and should reduce hydro depreciation expense by
12 ~\$15.7M annually.

13 **Deferred Maintenance and Local Reliability**

- 14 • The Commission should fund distribution system maintenance at levels sufficient to
15 address PG&E's deferred maintenance backlog, as requested by Coalition of California
16 Utility Employees (CCUE), but should not approve costs PG&E cannot demonstrate it
17 can execute within the GRC period.
- 18 • The Commission should not burden ratepayers with higher costs of emergency equipment
19 replacement driven by catastrophic failures attributable to a systemic pattern of failing to
20 conduct routine maintenance. Both Cal Advocates and TURN highlight these patterns
21 and effects on ratepayers in their testimony.
- 22 • The Commission should reject TURN's proposed probabilistic "hazard-based
23 framework" and instead should apply the Average Age of Failure as a more appropriate
24 metric for distribution circuit breaker replacement (MAT 48D).
- 25 • The Commission should, before approving nearly a four-fold increase in Emergent
26 Reliability Program spending, require PG&E to demonstrate which reliability metrics
27 will improve as a result of this spending, and exactly by how much. This
28 recommendation is distinct from the assertions of TURN and Cal Advocates.
- 29 • The Commission should not allow or incentivize PG&E to defer authorized distribution
30 system maintenance work while also inflating the per-unit cost of the work performed
31 during each rate cycle. The Commission should scrutinize all of the per-unit distribution
32 maintenance costs that Cal Advocates asserts are inflated, but it should not reduce service
33 need or replacement volume estimates.
- 34 • The Commission should require PG&E to analyze and compare the cost of completing
35 work with contractors vs PG&E employees, for each Major Work Categories (MWC) and
36 Maintenance Activity Type (MAT), as recommended by CCUE.

37 **Cost Escalation for Maintenance, Distribution Grid Resiliency (Grid Hardening), and** 38 **Asset Depreciation**

- 1 • The Commission should evaluate applying EPUC's recommended adjustment to the
2 capital escalation factor for overhead maintenance costs. EPUC asserts this will reduce
3 post test year (PTY) authorizations by \$170M–\$217M annually.
- 4 • The Commission should require PG&E to use Commission-adopted cost-per-mile
5 estimates for undergrounding, as asserted by Cal Advocates, rather than PG&E's higher
6 figures.
- 7 • The Commission should treat the prior GRC's hybrid portfolio mix (~61%
8 undergrounding, ~39% covered conductor) as a ceiling, not a floor.

9 **Bundled Versus Unbundled Customer Cost Responsibility**

- 10 • The Commission has sufficient record in this proceeding to make a facility-by-facility
11 reventing determination for the eight hydro facilities that PG&E needs to re-license.
12 This determination should be "fact-specific to the plants and spending in question"¹
13 according to D.18-10-019 and the factors identified in D.23-11-069.
- 14 • The Commission should ensure that PG&E is not overcharging Community Choice
15 Aggregators (CCAs) and Direct Access (DA) customers for metering and billing services,
16 as CalCCA concludes it has done, and must ensure that if customers overpaid, refunds are
17 returned to ratepayers.

18 **Load Growth and Energization**

- 19 • The Commission should, as CLECA requests, subject the costs of serving increased load
20 to rigorous scrutiny, to ensure that load growth can bring about expected overall
21 downward pressure on rates. Along these lines, the Commission should require PG&E to
22 sequence and size load growth investments appropriately within rate case cycles by using
23 the most up-to-date demand forecasts.
- 24 • The Commission should keep issues regarding how customers pay up front for large scale
25 upgrades to the appropriate interconnection proceedings, such as the Rule 30 proceeding
26 and any future updates to Rule 15. This rate case is not the appropriate place for the issue
27 of costs paid up-front by customers rather than ratepayers.
- 28 • The Commission should exclude 2024–2026 Electric Capacity and New Business Interim
29 Memorandum Account (ECNBIMA) capital from plant values pending Track 3 review,
30 but separately and independently ensure (or require PG&E to ensure) that the 2027-2030
31 forecast is set at a level that reflects the feasible pace of energization activity, based on
32 observations regarding what is achievable, regardless of how the 2024-2026 plant values
33 are ultimately treated. The Commission should ensure that the 2027-2030 forecast
34 reflects the demonstrated, and approved energization need.
- 35 • The Commission should deny PG&E's proposed New Business Balancing Account, as
36 requested by multiple parties. Rather, new business costs should be feasible to forecast
37 and budgeted in the GRC, as observed by CLECA.

¹ D. 18-10-019, "Decision Modifying the Power Charge Indifference Adjustment Methodology," issued October 19, 2018, in R.17-06-026 at 135.

1 **III. RATE INCREASES AND SCRUTINY OF THE OVERALL REVENUE**
2 **REQUIREMENT**

3 **Q.** Please identify the opening testimonies and list issues raised by each party’s Opening
4 Testimony which you will address in this section.

5 **A.** This section addresses:

- 6 • “Opening Testimony of Sam Harper and John Holler on behalf of California Large
7 Energy Consumers Association” filed February 13, 2026, in A. 25-05-009, discussing (1)
8 the standard for success in this proceeding, framed as meaningful near-term and long-
9 term rate reductions across all customer sectors, and (2) the feedback loop between rate
10 increases and beneficial electrification adoption.
- 11 • “Opening Testimony of Michael Colvin on Behalf of Environmental Defense Fund” filed
12 February 13, 2026, in A. 25-05-009, discussing PG&E's failure to establish an overall
13 budget constraint and the risk that item-by-item review of the Application will not
14 produce just and reasonable rates in the aggregate.
- 15 • CA-27, “Post-Test Year Ratemaking, Testimony of D. Phan on behalf of Cal Advocates,”
16 filed February 13, 2026, in A.25-05-009, discussing PG&E's proposed attrition formula
17 and the appropriate attrition methodology, contrasting PG&E's 6% annual attrition with a
18 Consumer Price Index (CPI)-based approach grounded in Commission precedent.

19 **Q.** Do you agree with CLECA's framing of the standard for success in this proceeding?

20 **A.** Yes, I agree with CLECA that “[t]he goal post for success must be meaningful electricity
21 rate reductions beginning in the near-term and sustained over the long-term, assuming reasonable
22 load growth forecasts, across all customer sectors.”² Similarly to CLECA, CLEU’s “members
23 have not typically participated in the base revenue requirement setting phase of PG&E’s GRC
24 due to the significant time and costs required to do so. Their decision to participate now
25 underscores the magnitude of concern with the revenue requirement request in this proceeding
26 and the potential impact on these customers’ operations.”³ CLEU was incorporated very
27 recently, and our members were motivated to form a new ratepayer organization not only
28 because of the impacts of PG&E’s rates on their own operations in California, but also based on
29 concerns with how general electricity unaffordability is affecting their “customers” who are

² “Opening Testimony of Sam Harper and John Holler on behalf of California Large Energy Consumers Association” filed February 13, 2026, in A. 25-05-009 (CLECA) at 4.

³ *Id* at 5.

1 students, patients, as well as business that provide the technology and innovation that drives
2 California's economy.

3 CLEU intervenes now because PG&E's revenue requirement is impacting the "end users" of
4 CLEU's members and services, which include over 300,000 University students, as well as
5 patients in the largest integrated healthcare organization in the US. PG&E's increased revenue
6 requirement will affect healthcare costs and education costs. PG&E's rate increases have
7 affected California's economy by reducing the disposable income of California households, and
8 are making people choose between paying their utility bill and buying food, and are affecting the
9 decisions of businesses to operate in California. I agree with CLECA that high rates suppress
10 economic growth by driving large loads out of the state.⁴ One of our members chose to locate a
11 new research facility outside of California specifically because of electricity costs.

12 CLEU's members are fully committed to California's decarbonization goals, which depend on
13 electrifying transportation and other sectors currently run on fossil fuels. Thus, I agree with
14 CLECA that there is a feedback loop created for beneficial electrification,⁵ and that could
15 become positive or negative depending on how well the Commission does its job: "If rates rise
16 too quickly or fail to moderate as a result of aggressive anticipatory capital spending,
17 electrification adoption may fall short of PG&E's projections."⁶

18 **Q.** Does EDF correctly identify a deficiency in PG&E's overall budget justification?

19 **A.** Yes, EDF's testimony identifies an important deficiency in PG&E's overall budget.⁷ I agree
20 that the Commission should also evaluate PG&E's application from an overall budget
21 perspective. "EDF's observation is that the Commission could examine the individual parts of
22 each request, modify them in response to intervenor's protests, and the sum of the individual
23 parts may not lead to just and reasonable rates"⁸ and CLEU shares this concern regarding the
24 cumulative impact of increased revenue requirements for the hundreds of line items that parties
25 are being asked to scrutinize in this proceeding. I agree with EDF's assessment that "PG&E has

⁴ CLECA at 28.

⁵ CLECA at 28.

⁶ CLECA at 28.

⁷ "Opening Testimony of Michael Colvin on Behalf of Environmental Defense Fund" filed February 13, 2026, in A. 25-05-009 (EDF) at 4.

⁸ EDF at 4.

1 not established an overall budget constraint and explained its reasoning of why the level of
2 investment into each of the programs is sufficient. The magnitude of the rate increase is too
3 high, and while each individual component may be worthy of consideration, in EDF’s estimation
4 if the Application were adopted without significant modifications, it would not lead to just and
5 reasonable rates.”⁹

6 **Q.** Between Cal Advocates’ and PG&E’s proposed attrition formulae, which do you consider
7 most consistent with Commission precedent?

8 **A.** Cal Advocates opposes PG&E’s attrition formula and advocates for a CPI-based attrition
9 rate that is consistent with Commission precedent, compared to PG&E’s 6% per year attrition.¹⁰
10 On attrition specifically, the Commission precedent that Cal Advocates cites is compelling, and
11 procedurally and precedentially, I agree with the ratepayer advocate’s approach.¹¹

12 **IV. BASE COSTS AND BASE REVENUE (INCLUDING DIABLO CANYON)**

13 **Q.** Please identify the issues regarding Base Cost and Base Revenue that you will address in
14 this section.

15 **A.** This section addresses:

- 16 • “Prepared Direct Testimony of Ryan Matley on Behalf of the California Community
17 Choice Association,” filed February 13, 2026, in A.25-05-009, discussing PG&E’s
18 continued collection of returns on thirteen non-operational hydro facilities, four of which
19 PG&E admits remain on its books in error, and the Commission’s authority under Public
20 Utilities Code § 455.5(a) to remove such assets from rates.
- 21 • TURN-02, “Affordability, Accountability and Deferred Work, Testimony of Jennifer
22 Dowdell on behalf of TURN,” filed February 13, 2026, in A.25-05-009, discussing the
23 exclusion of more than \$5 billion in costs from PG&E’s headline revenue requirement
24 figure, including \$4.12 billion allocated to Diablo Canyon over 2027–2030.
- 25 • “Direct Testimony and Exhibits of James A. Leyko On behalf of Energy Producers &
26 Users Coalition (“EPUC”) and Indicated Shippers (“IS”),” filed February 13, 2026, in
27 A.25-05-009, discussing PG&E’s proposed use of the \$712 million Variable Performance
28 Fee from Diablo Canyon’s extended operations and whether that use aligns with the
29 statutory purpose established in Public Utilities Code Section 712.8(q).

⁹ EDF at 5.

¹⁰ “Post-Test Year Ratemaking, Testimony of D. Phan on behalf of Cal Advocates,” filed February 13, 2026, in A.25-05-009 (CA-27) at 4.

¹¹ CA-27 at 4.

1 **Q.** Has CalCCA identified material issues with the inclusion of defunct hydropower facilities in
2 PG&E’s calculations for the Electric Generation revenue requirement? Has PG&E corrected the
3 errors in their filing?

4 **A.** California Public Utilities Code (PU Code) § 455.5(a) gives the Commission explicit
5 authority to remove assets from rates after nine or more consecutive months out of service.¹²
6 CalCCA's testimony identifies that PG&E is continuing to collect a return on thirteen hydro
7 facilities that PG&E has either retired or sold, or which are physically incapable of
8 generating electricity.¹³ CalCCA identifies that in some cases these resources have been on
9 the books erroneously for over a decade.¹⁴ PG&E has admitted in discovery that four of the
10 thirteen facilities (Coal Canyon, Lime Saddle, Kern Canyon, Chili Bar) remain on its books
11 in error.¹⁵ The other nine are “mothballed” or physically incapable of generation:
12 Centerville last operated in 2011, Kerckhoff 1 in 2017, Inskip in 2017, and Hamilton Branch
13 in 2018.¹⁶ PG&E's proposal would have ratepayers collecting returns on these assets for up
14 to 19 years of non-operation.¹⁷

15 I do not find any legitimate basis for delaying the removal of these facilities from the
16 ratebase. CLEU agrees with CalCCA that these assets should be removed from the Electric
17 Generation revenue requirement immediately, with any remaining net book value (~\$45.2M)
18 recovered as a regulatory asset with no return.¹⁸ This is a straightforward accounting
19 correction that reduces the 2027 revenue requirement by \$10.6M net.¹⁹ Furthermore, I
20 observe that ratepayers should be retroactively “made whole” through compensation for the
21 errors that were known or should have been known, to PG&E in prior rate cases.

22 **Q.** Do you agree with TURN's observation that PG&E's headline revenue requirement figure
23 understates the total costs customers will face?

¹² Cal. Pub. Utls. Code § 455.5(a).

¹³ “Prepared Direct Testimony of Ryan Matley on Behalf of the California Community Choice Association,” filed February 13, 2026, in A.25-05-009 (CalCCA) at 7-8.

¹⁴ CalCCA at 8-9.

¹⁵ CalCCA at 9-10.

¹⁶ CalCCA at 8-9.

¹⁷ CalCCA at 18.

¹⁸ CalCCA at 20.

¹⁹ CalCCA at 21.

1 A. TURN identifies that PG&E's headline revenue requirement figure excludes more than \$5
2 billion in costs customers will actually face during the GRC period, including \$4.12 billion
3 allocated to Diablo Canyon over 2027 through 2030.²⁰ CLEU agrees with TURN that the costs
4 included must be complete. If costs will be borne by ratepayers during the 2027 GRC cycle,
5 they must be visible and subject to scrutiny in this proceeding, regardless of how PG&E has
6 chosen to account for them. Excluding Diablo Canyon costs from the headline figure does not
7 make those costs disappear; it simply removes them from the record where intervenors can
8 examine them and where the Commission can evaluate whether the total burden on ratepayers is
9 just and reasonable. The Commission cannot make a reasonableness determination with
10 incomplete information, all costs that will flow through to ratepayers during this GRC period
11 should be in front of the Commission now and not piecemeal in separate proceedings, which
12 would obscure the full picture of the costs' impacts on ratepayers.

13 The Commission's own 2025 Senate Bill (SB) 695 report, which TURN quotes directly,
14 describes the GRC as the primary mechanism through which the Commission imposes discipline
15 on utility spending: an enterprise-wide review designed to identify the most cost-effective
16 options and determine revenue requirements at the lowest just and reasonable rates.²¹ TURN's
17 point, which CLEU agrees with, is that this mechanism only works if all the costs are in front of
18 the Commission at once. Fragmentation of the revenue requirement across separate proceedings,
19 balancing accounts, and legislative arrangements defeats the purpose of the GRC process. The
20 Commission cannot make a holistic affordability determination on an incomplete picture, and it
21 cannot hold PG&E accountable for delivering value for money if the full price tag is never
22 presented in a single place.

23 Q. Do you agree with EPUC regarding PG&E's proposed use of Variable Performance Fee
24 revenue from Diablo Canyon operations and how it should be used?

25 A. In his testimony for EPUC, James Leyko raises a concern about PG&E's stated intention to
26 use the \$712 million Variable Performance Fee (VPF) revenue from Diablo Canyon's extended

²⁰ "Affordability, Accountability and Deferred Work, Testimony of Jennifer Dowdell on behalf of TURN," filed February 13, 2026, in A.25-05-009 (TURN-02) at 8-12.

²¹ TURN-02 at 5-7.

1 operations in a manner inconsistent with the stated goal of extending the plant.²² He argues that
2 the proposed use of VPF revenue in the PTY period undermines the rationale for the fee and
3 should be revisited.²³ I agree that the funds should be used in a manner related to resource
4 adequacy or electric procurement. CLEU recommends that the funds be directly used to offset
5 PG&E ratepayer expenses related to electric procurement: this \$712 million could be used to
6 reduce ratepayer costs for Resource Adequacy, or for real time energy market expenses. Both of
7 these would be related to the statutory purpose of extending Diablo Canyon’s operations which
8 was supposedly for reliability and to decrease scarcity conditions.²⁴ It appears that the \$712 is
9 currently being treated as a “windfall” for PG&E.²⁵ Instead, these funds should be returned to
10 the ratepayers in as direct a manner as possible. Thus, in my opinion, offsetting Resource
11 Adequacy (RA) or energy market costs in the 2027 cycle is logical.

12 **V. DEPRECIATION OF EXISTING ASSETS**

13 **Q.** Please identify the issues regarding Base Cost and Base Revenue that you will address in
14 this section.

15 **A.** This section addresses the “Prepared Direct Testimony of Ryan Matley on Behalf of the
16 California Community Choice Association,” filed February 13, 2026 in A.25-05-009, discussing
17 (1) a \$15.7M annual overcharge in PG&E's hydro depreciation expense resulting from PG&E's
18 omission of \$507–\$562M of accumulated depreciation from its depreciation study, and (2) the
19 discrepancy between PG&E's GRC filing and its own books and Federal Energy Regulatory
20 Commission (FERC Form 1.

21 **Q.** Do you agree with CalCCA’s position on PG&E’s hydropower depreciation expenses?

22 **A.** Yes, I agree with CalCCA that overcharges for hydro-depreciation should be corrected.
23 CalCCA identifies a \$15.7M annual overcharge in PG&E's hydro depreciation expense,
24 resulting from PG&E’s omission of \$507–\$562M of accumulated depreciation from its
25 depreciation study.²⁶ CalCCA observes that there is a direct contradiction between PG&E's

²² “Direct Testimony and Exhibits of James A. Leyko On behalf of Energy Producers & Users Coalition (“EPUC”) and Indicated Shippers (“IS”),” filed February 13, 2026, in A.25-05-009, (EPUC) at 40-41.

²³ EPUC at 41-42.

²⁴ EPUC at 41-42.

²⁵ EPUC at 41.

²⁶ CalCCA at 50-52.

1 own books and PG&E’s “Form 1” filings at FERC.²⁷ CLEU agrees that this should be
2 corrected. If left uncorrected, CalCCA’s analysis shows that customers will pay \$507–
3 \$562M more than the original cost of the hydro fleet over the life of the assets.²⁸ CLEU
4 finds this to be unacceptable. I observe that there is no dispute regarding the calculation
5 methods, rather the discrepancy is between what PG&E provides to the Commission in its
6 GRC filing and what it reports on its own books.²⁹ The Commission should require PG&E
7 to reconcile these figures and reduce the depreciation expense accordingly.

8 VI. DEFERRED MAINTENANCE AND LOCAL RELIABILITY

9 Q. Please identify the opening testimonies and list issues raised by each party’s Opening
10 Testimony which you will address in this section.

11 A. This section addresses:

- 12 • “Testimony of Robert Earle on Behalf of the Coalition of California Utility Employees,”
13 filed February 13, 2026, in A.25-05-009, discussing: (1) the consequences of deferred
14 maintenance on poles, overhead conductors, and underground cable, including outages,
15 public safety hazards, and wildfire ignition, and (2) the need for PG&E to develop and
16 make available cost data comparing contractor versus internally performed work for each
17 MWC and MAT.
- 18 • CA-03, “Electric Distribution Capital Expenditures, Part 1 of 6, Testimony of R. Amin on
19 behalf of Cal Advocates,” filed February 13, 2026, in A.25-05-009, and CA-28, “Safety,
20 Risk and Integrated Planning, Testimony of M. Gordon, L. Vanderbilt, and M. Hanauer
21 on behalf of Cal Advocates,” filed February 13, 2026, in A.25-05-009. These testimonies
22 discuss: (1) chronic underspending on overhead conductor replacement and five
23 consecutive years of deferrals, and (2) the link between deferred proactive maintenance
24 and elevated emergency repair costs.
- 25 • CA-04, “Electric Distribution Capital Expenditures, Part 2 of 6,” Testimony of G. Wilson
26 on behalf of Cal Advocates, filed February 13, 2026, in A.25-05-009, discussing inflation
27 in PG&E’s per-unit cost calculations for distribution maintenance components.
- 28 • TURN-02, “Affordability, Accountability and Deferred Work,” Testimony of Jennifer
29 Dowdell on behalf of TURN, filed February 13, 2026, in A.25-05-009, discussing
30 worsening reliability metrics despite increased Emergent Reliability Program spending.
- 31 • TURN-11, “Addressing Substation Asset Management, Testimony of Jalal Awan, Ph.D.
32 on behalf of TURN,” filed February 13, 2026, in A.25-05-009, discussing: 1) PG&E’s
33 blended “Average Age of Failure” metric for distribution circuit breaker replacement
34 (MAT 48D) and 2) TURN’s proposed reduction to 30 units per year.

²⁷ CalCCA at 50-52.

²⁸ CalCCA at 53.

²⁹ CalCCA at 52.

- 1 • “Opening Testimony of Sam Harper and John Holler on behalf of California Large
2 Energy Consumers Association” filed February 13, 2026, in A. 25-05-009, discussing
3 limiting approved capital work to activities PG&E has demonstrated it can reasonably
4 execute within the GRC period.

5 **Q.** Do you agree with CCUE's characterization of the consequences of deferred maintenance?

6 **A.** I Agree with CCUE on the dire consequences for reliability that occur when elements of
7 PG&E’s distribution system fail, caused by lack of maintenance investment. CLEU’s mission is
8 focused on maintaining reliability alongside ensuring affordability, and thus CCUE’s assertion
9 that “PG&E’s overhead conductor replacement has fallen woefully short for many years and
10 continues to do so under PG&E’s forecast”³⁰ is of grave concern to CLEU, as leading businesses
11 and institutions in the state. Outages caused by distribution system failures have severely
12 impacted Californians in recent months,³¹ and these outages have directly impacted CLEU and
13 the customers our members serve. CCUE’s Testimony asserts: “[f]ailure of utility poles and
14 non-timely replacement can have dire consequences for the public at large as well as ratepayers.
15 Some examples are... a major blackout event associated with 8 utility poles, the 2011 Windstorm
16 Event resulting in more than 440,000 customers losing power after utility poles and attachments
17 were blown down by a windstorm.”³² Also, “[f]ailure of overhead conduit can cause customer
18 outages, danger to the public when they fall to the ground and remain energized, and ignition of
19 wildfires. Proactive replacement of aging overhead conduits is therefore necessary for safety and
20 reliability.”³³ Preventing catastrophic grid events, especially those that pose public health and
21 safety hazards and real economic losses across the state, is a priority for CLEU.

22 **Q.** Do you agree that ratepayers shouldn’t be stuck with the higher costs of “emergency”
23 maintenance when routine, proactive maintenance was systematically deferred, as asserted
24 by Cal Advocates?

³⁰ “Testimony of Robert Earle on Behalf of the Coalition of California Utility Employees,” filed February 13, 2026, in A.25-05-009 (CCUE) at 12.

³¹ “Fire at PG&E substation in Saratoga causes power outage for over 20,000 customers on Christmas Eve,” ABC7 San Francisco (Dec. 25, 2025), available at <https://abc7news.com/post/fire-pge-substation-saratoga-causes-power-outage-20000-customers-christmas-eve/18312652/>; “Tens of thousands across Bay Area lose power on Christmas morning as another storm moves through,” CBS San Francisco (Dec. 25, 2025), available at <https://www.cbsnews.com/sanfrancisco/news/bay-area-christmas-eve-storm-wind-power-outages/>.

³² CCUE at 4-5.

³³ CCUE at 10.

1 A. Yes, I observe a pattern identified by both Cal Advocates and TURN in their various
2 testimonies that “an ounce of prevention is worth a pound of flesh.” Cal Advocates
3 documents that there has been chronic underspending on overhead conductor replacement by
4 56%–88%³⁴ and that this has been coupled with five consecutive years of,³⁵ meaning that the
5 funds authorized in prior GRCs were not spent on the overhead conductor replacements that
6 PG&E previously said were necessary. TURN and Cal Advocates highlight that emergency
7 repairs and replacements that were *more expensive by many orders of magnitude* resulted
8 from PG&E not completing work that was necessary at the time the Commission approved
9 the work.³⁶ The data presented by PG&E and through discovery shows that 32% of
10 conductor-related emergency repairs were driven by conductor failure³⁷—meaning ratepayer
11 funds are now requested for emergency fixes to equipment that PG&E should have
12 proactively replaced. This directly supports my conclusion that emergency (reactive)
13 spending stems from deferred proactive maintenance.

14 Q. Does TURN's criticism of PG&E's Average Age of Failure metric justify TURN's
15 recommended reduction in authorized replacement units?

16 A. No. I disagree with TURN's conclusion that its criticism of the metric warrants the reduction
17 TURN proposes. TURN argues that PG&E's blended " Average Age of Failure" metric for
18 distribution circuit breaker replacement (MAT 48D) "does not isolate catastrophic or
19 operational failures and does not establish an increasing hazard rate,"³⁸ and TURN
20 recommends a probabilistic hazard-based framework (e.g., Weibull analysis), proposing only
21 30 units per year for 2028-2030 versus PG&E's ramp to 90 units — a 37% cost reduction
22 totaling \$71.8M against PG&E's \$160M request.³⁹ While TURN may be correct that the
23 blended metric conflates in-service failures with preventive replacements, the metric need
24 not isolate catastrophic failures to serve its purpose. The relevant question is what

³⁴ “Electric Distribution Capital Expenditures, Part 1 of 6, Testimony of R. Amin on behalf of Cal Advocates,” filed February 13, 2026, in A.25-05-009 (CA-03) at 44-45.

³⁵ “Safety, Risk and Integrated Planning, Testimony of M. Gordon, L. Vanderbilt, and M. Hanauer on behalf of Cal Advocates,” filed February 13, 2026, in A.25-05-009 (CA-28) at 29.

³⁶ TURN-02 at 28-30.

³⁷ CA-28 at 33-35.

³⁸ “Addressing Substation Asset Management, Testimony of Jalal Awan, Ph.D. on behalf of TURN,” filed February 13, 2026, in A.25-05-009 (TURN-11) at 7.

³⁹ TURN-11 at 7-9.

1 authorization level is reasonable for this MAT, and the Average Age of Failure metric is
2 adequate for that purpose. Notably, TURN's own recommended alternative, a flat 30 units
3 per year, is itself not derived from the probabilistic framework TURN advocates for, which
4 undermines the force of its methodological critique.

5 Separately, the Commission should consider whether PG&E is entitled to earn a return on
6 replacements driven by catastrophic failure. Where an asset has failed catastrophically due
7 to inadequate maintenance, that failure represents a performance shortcoming PG&E should
8 not profit from: the Commission should authorize recovery of replacement costs, but deny a
9 return on those investments as an accountability measure reflecting that the failure should
10 not have occurred in the first place.

11 **Q.** Do you agree with CLECA's recommendation to prioritize and limit approved capital work
12 to activities PG&E can reasonably execute within the GRC period?

13 **A.** I agree with CLECA's recommendation, and their significant caveat. CLECA argues: "[t]he
14 Commission should prioritize and limit approved capital work in this GRC to only those
15 activities that are necessary, urgent, and that PG&E has demonstrated it can reasonably execute
16 within the GRC period."⁴⁰ CLECA's last point about feasibility and timing is extremely
17 important. While the record clearly demonstrates an incredible quantity of deferred system
18 maintenance,⁴¹ the record also shows it is unlikely it can all be completed within the pertinent
19 time window for this GRC.⁴² Thus, I agree that costs should not be approved in this rate case
20 unless PG&E has clearly demonstrated, based on present and recent experience, that all of the
21 budgeted work can be completed.

22 **Q.** How do you respond to assertions in TURN and Cal Advocates testimony that PG&E's
23 increased Emergent Reliability Program spending coincided with worsening reliability
24 metrics?

25 **A.** I observe, based on the testimony and my review of PG&E's application, that PG&E is
26 asking for a very large increase for the Emergent Reliability Program in 2027. As noted by

⁴⁰ CLECA at 7.

⁴¹ CLECA at 29.

⁴² CLECA at 29.

1 TURN⁴³ and Cal Advocates,⁴⁴ PG&E seeks \$28M more than it did in the 2023 GRC:
2 approximately 294% increase. I would recommend that the Commission require the utility to
3 demonstrate how exactly they plan to improve reliability metrics through this increase. TURN's
4 and CalAdvocate's testimonies discuss the various safety metrics employed by PG&E: System
5 Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index
6 (SAIFI) ,Momentary Average Interruption Frequency Index (MAIFI), and Customer Average
7 Interruption Duration Index (CAIDI) and assert that the data on reliability shows reliability
8 metrics have worsened while spending has increased.⁴⁵ According to TURN, "reliability metrics
9 exclusive of major events have declined even as revenues have increased." All four metrics
10 (SAIDI, SAIFI, MAIFI, CAIDI) worsened, and "since 2015 all of PG&E's electric reliability
11 metrics have been on a path of decline."⁴⁶ Since improving reliability is one of CLEU's goals as
12 an organization, I would also conclude that if reliability metrics and spending on a reliability
13 program have an inverse relationship, the Commission needs to re-evaluate the justification for
14 these programs.

15 **Q.** Does Cal Advocates correctly identify inflation in PG&E's per-unit cost calculations for
16 distribution maintenance, and what aspects of its position does CLEU endorse?

17 **A.** CLEU does not object to Cal Advocates' position regarding the per-unit cost calculations for
18 distribution maintenance components. Cal Advocates' analysis identifies that PG&E has inflated
19 per-unit costs across multiple Major Work Categories (MWC), including MWC 7 / MAT 07D
20 and MWC 2A / MAT 2AA.⁴⁷ The Commission should scrutinize the inflation, and require
21 PG&E to justify it. CLEU would, however, object to any remedy that reduces service need or
22 replacement estimates, because distribution system reliability is critical for all customers,
23 especially CLEU's members. As I discuss above, PG&E has chronically underspent previously
24 authorized maintenance budgets, and that pattern of deferred maintenance has directly
25 contributed to costlier emergency repairs. The per-unit cost inflation Cal Advocates identifies

⁴³ TURN-02 at 27-30.

⁴⁴ CA-03 at 53-54

⁴⁵ CA-03 at 53-54.

⁴⁶ TURN-02 at 28.

⁴⁷ "Electric Distribution Capital Expenditures, Part 2 of 6," Testimony of G. Wilson on behalf of Cal Advocates, filed February 13, 2026, in A.25-05-009 (CA-04) at, 43-55.

1 should be evaluated in that context: the Commission should not allow PG&E to defer authorized
2 work while also inflating the per-unit cost of the work it does perform.

3 **Q.** Do you support CCUE's recommendation that PG&E develop and make available cost
4 comparisons for work performed by contractors vs. employees?

5 **A.** Yes. CCUE recommends that "PG&E should develop and/or make available costs for each
6 MWC and/or MAT for contractor versus internally performed work" and that "this cost data
7 should be used to inform PG&E's workforce planning."⁴⁸ I agree. Cal Advocates' own analysis
8 demonstrates precisely why such transparency matters: PG&E's increased reliance on contractor
9 labor has inflated unit costs across multiple MWCs,⁴⁹ and PG&E lacks the granular cost data to
10 evaluate whether its contractor spending represents the least-cost approach to performing the
11 work.⁵⁰ Without that data, neither the Commission nor intervenors can verify whether PG&E
12 pursues the least-cost labor approach.

13 CCUE identifies three additional deficiencies in PG&E's workforce planning that reinforce the
14 need for this data. First, PG&E admits that its 60/40 contractor split relies on historical operating
15 ratios rather than any specific analysis of future work composition, and that "PG&E has no
16 defined criteria, thresholds, or quantitative measures" to support this ratio.⁵¹ Second, the limited
17 cost data that does exist (for MWC 16) shows contractors to be substantially more expensive
18 than internally performed work in the short term.⁵² Third, PG&E's Section 935 Report fails to
19 account for attrition or retirement considerations in its headcount analysis, meaning PG&E "does
20 not attempt to show how many total hires must occur to reach the total headcount."⁵³ These gaps
21 confirm that PG&E lacks the analytical foundation to justify its current labor allocation, and that
22 the cost comparison data CCUE recommends is essential for informed workforce planning
23 decisions.

⁴⁸ CCUE at 25.

⁴⁹ CA-04 at 41-47, 52-55

⁵⁰ *Id.*

⁵¹ CCUE at 24.

⁵² CCUE at 25.

⁵³ CCUE at 27.

1 **VII. COST ESCALATION FOR MAINTENANCE, DISTRIBUTION GRID**
2 **RESILIENCY (GRID HARDENING), AND ASSET DEPRECIATION**

3 **Q.** Please identify the opening testimonies and list issues raised by each party’s Opening
4 Testimony which you will address in this section.

5 **A.** This section addresses:

- 6 • “Direct Testimony and Exhibits of James A. Leyko On behalf of Energy Producers &
7 Users Coalition (“EPUC”) and Indicated Shippers (“IS”),” discussing: 1) the likely cause
8 of PG&E’s 33% annual growth rate for electric distribution overhead maintenance and (2)
9 the significant PTY reductions that would result from applying the capital escalation
10 factor instead.
- 11 • CA-03, “Electric Distribution Capital Expenditures, Part 1 of 6, Testimony of R. Amin on
12 behalf of Cal Advocates,” filed February 13, 2026, in A.25-05-009, discussing: (1)
13 PG&E’s divergence from Commission precedent on cost-per-mile estimates for wildfire
14 system hardening and undergrounding, and (2) the appropriate mix of undergrounding
15 versus covered conductor compared with the portfolio approved in the prior GRC.

16 **Q.** Does EPUC accurately identify a flaw in PG&E’s methodology for 2027 base maintenance
17 costs and justification for escalating those base costs?

18 **A.** EPUC’s witness, James Leyko, asserts that PG&E’s base costs in the 2027 test year are
19 inflated.⁵⁴ EPUC asserts that the inflation of base costs is primarily driven by PG&E’s bottom-
20 up forecast methodology for electric distribution overhead maintenance, which proposes a 33%
21 annual growth rate from current spending levels.⁵⁵ I agree that such a large growth rate is
22 concerning and potentially unjustified. Leyko recommends applying the capital escalation factor
23 to overhead maintenance costs (MWC 2A) rather than the 33% annual growth implied by
24 PG&E’s bottom-up forecast.⁵⁶ This single adjustment produces the following, significant PTY
25 reductions: 2028: - \$170 million, 2029: -\$180 million, and 2030: -\$217 million.⁵⁷ I agree that
26 these are significant potential reductions, and the Commission should carefully analyze the
27 reasonableness of the modified capital escalation factor.

⁵⁴ EPUC at 8-9.

⁵⁵ EPUC at 26-28.

⁵⁶ EPUC at 26-29.

⁵⁷ EPUC at 10.

1 Q. Do you agree with Cal Advocates' position on distribution system hardening costs and the
2 cost per mile for undergrounding?

3 A. I observe that Cal Advocates points out a material and important divergence from
4 Commission precedent in PG&E's calculation for the cost of wildfire system hardening and
5 undergrounding. Specifically, PG&E estimates the costs of such activities at \$3.03–\$3.26
6 million per mile.⁵⁸ Cal Advocates testimony reminds us of the Commission's decision, D.23-11-
7 069, approximated that undergrounding costs in 2023 should be *declining to* approximately \$2.8
8 million per mile in 2026, with a four-year average of approximately \$2.97 million per mile.⁵⁹
9 CLEU agrees with the ratepayer advocate that PG&E should use the estimates adopted by the
10 Commission and that it has not justified such an extreme divergence from the previously
11 estimated costs.

12 Q. What is your position on the appropriate mix of undergrounding versus covered conductors?

13 A. I agree with Cal Advocates' witness who argues that precedent should be followed: in the
14 prior GRC, the Commission approved: the hybrid portfolio (approximately 1,230 miles
15 undergrounding and 778 miles covered conductor out of 2,008 total miles for 2023–2026),
16 corresponding to roughly 61% undergrounding and 39% covered conductor.⁶⁰ CLEU agrees
17 with applying the hybrid portfolio for undergrounding, but I recommend that it be viewed as a
18 ceiling and not a floor, as undergrounding is clearly a major driver of the overall revenue
19 requirement, which EDF points out may result in unjust and unreasonable rates.

20 **VIII. BUNDLED VERSUS UNBUNDLED CUSTOMER COST RESPONSIBILITY**

21 Q. Please identify the issues you will address in this section.?

22 A. This section addresses the “Prepared Direct Testimony of Ryan Matley on Behalf of the
23 California Community Choice Association,” filed February 13 2025 in A.25-05-009, discussing:
24 (1) the application of the Commission's D.18-10-019 revintaging framework to PG&E's
25 proposed investments in eight hydropower facilities undergoing FERC relicensing, and whether
26 to revintage those facilities uniformly or on a facility-by-facility basis, and (2) PG&E's

⁵⁸ CA-03 at 26.

⁵⁹ CA-03 at 26.

⁶⁰ CA-03 at 28.

1 systematic overcharging of CCA and Direct Access customers for metering and billing services
2 based on a 2015 cost study, as well as (3) the \$10.3M surplus collected from 2020–2024 for
3 billing services that PG&E erroneously allocated to bundled customers rather than returning it to
4 unbundled customers.

5 **Q.** How does Commission precedent establishing a revintaging framework apply to PG&E's
6 proposed hydro relicensing investments raised in CalCCA's testimony?

7 **A.** D.18-10-019 and D.23-11-069 provide the framework for revintaging utility-owned
8 generation assets and deciding which costs are germane to specific "vintages" of the Power
9 Charge Indifference Adjustment (PCIA).⁶¹ The framework identifies four potential revintaging
10 triggers: asset life extension, capacity expansion, changed function, and investment constituting a
11 "significant overhaul."⁶² D.18-10-019 lays out that bundled customers should not subsidize
12 unbundled customers, but also that unbundled customers should not subsidize new generation
13 commitments made on behalf of bundled customers.⁶³ This decision also provides that requires
14 the analysis be "fact-specific to the plants and spending in question."⁶⁴ D.23-11-069 then
15 directed PG&E to include in this very filing "(1) the details of any PG&E proposal for new asset
16 life extensions, incremental capacity additions, or changed functions for any of its Utility-Owned
17 Generation (UOG) assets... (2) on whose behalf it is making these new investments, and (3) the
18 appropriate vintaging treatment for each asset."⁶⁵

19 **Q.** How does your position compare to CalCCA's recommendation to apply the revintaging
20 framework across eight hydro facilities, which PG&E is in the process of relicensing?

21 **A.** CLEU agrees with CalCCA that the Commission must make a determination regarding the
22 revintaging of each of these assets. The issue before the Commission in this proceeding is a
23 consequence of the Commission's prior approach to revintaging questions, which left significant
24 issues unresolved. In D.18-10-019 the Commission held that any revintaging analysis must be

⁶¹ CalCCA at 21-22.

⁶² D.18-10-019 at 135.

⁶³ D.18-10-019 at 135.

⁶⁴ D.18-10-019 at 135.

⁶⁵ D. 23-11-069, "Decision on Pacific Gas and Electric Company's 2023 General Rate Case," issued November 17, 2023, in A.21-06-021 at 511.

1 “fact-specific to the plants and spending in question,”⁶⁶ but the Commission did not define what
2 constitutes a “significant overhaul” or “significance” for these purposes. In D.23-11-069, the
3 Commission directed PG&E to include in its future GRC filings “(1) the details of any PG&E
4 proposal for new asset life extensions, incremental capacity additions, or changed functions for
5 any of its UOG assets and why it is undertaking these changes, (2) on whose behalf it is making
6 these new investments, and (3) the appropriate vintaging treatment for each asset in light of this
7 testimony along with any future GRC proposals,”⁶⁷ but the Commission stopped short of
8 ordering a case-by-case revintaging assessment by PG&E despite having ample data on which to
9 make its findings. The result is that this GRC now presents the Commission with approximately
10 \$1 billion in forecasted hydropower capital expenditures across the eight facilities that must go
11 through FERC relicensing, without this having automatically triggered a revintaging analysis.
12 The Commission must now establish the appropriate process and establish a clear precedent.
13 The Commission now has sufficient information on each of these eight facilities to make a “fact-
14 specific” case by case determination on “the plants and spending in question” as it established in
15 D.18-10-019.⁶⁸ There is no logical reason to further delay adopting a binding precedent for how
16 utility-owned generation will be treated prospectively when undergoing relicensing or major
17 capital improvements. Each of the eight carries forecast capital investment of at least \$59
18 million, or at minimum 17% of the original cost of the facility. Both CalCCA and PG&E have
19 provided information regarding the facility-by-facility investment magnitudes, the asset life
20 extension impacts, the changed function of the facilities, and on whose behalf the investments
21 are being made. PG&E cannot credibly contend that a facility requiring either hundreds of
22 millions of dollars in capital investment, or a significant portion of its original cost to build is not
23 a “significant overhaul” sufficient to trigger revintaging review under D.18-10-019, as that
24 decision expressly opened the door to revintaging in cases of a “significant overhaul” or “plant
25 investments[or] upgrades.”⁶⁹

26 To clarify our recommendation: I find that the Commission now has sufficient record in this
27 proceeding to make a determination, based on the “significant overhaul” factor in D.18-10-019

⁶⁶ D.18-10-019 at 134–135.

⁶⁷ D.23-11-069 at 511.

⁶⁸ D.18-10-019 at 134–135.

⁶⁹ Id.

1 and the factors identified in D.23-11-069, as to whether these hydro resources must be
2 revintaged. CLEU recommends that the Commission finalize a decision on the revintaging of
3 these eight assets in this proceeding.

4 **Q.** Do you agree with CalCCA that PG&E's metering and billing charges to CCA and Direct
5 Access customers are unjust and require correction?

6 **A.** I agree with CalCCA that, based on the data presented in its testimony, PG&E is likely
7 overcharging CCA and Direct Access customers for metering and billing services.⁷⁰ PG&E has
8 not contested that its current billing rates are based on a 2015 cost study, or that from 2020-2024
9 it collected \$10.3M more from CCA/DA customers than it spent on those services and then
10 allocated the surplus back to bundled customers.⁷¹ CalCCA argues this is a direct violation of
11 the indifference principle,⁷² and if customers were overcharged, I agree that a subsidy from
12 unbundled to bundled customers violates the Commission's indifference principle.

13 In the beginning, designing a billing system for CCA customers required a lot of administrative
14 time and systems development by PG&E. Now that these systems have been standardized, it
15 would be reasonable to expect costs per capita to decline.⁷³ Yet the costs per customer do not
16 seem to have decreased. There seems to be a subsidy flowing from CCA/DA customers to
17 bundled customers. This is precisely the outcome the Commission's framework is designed to
18 prevent. CLEU supports CalCCA's recommendation to cap billing revenues at forecasted cost
19 and refund any excess through Energy Resource Recovery Account (ERRA) pending a Phase 2
20 cost study update.

21 **IX. LOAD GROWTH & ENERGIZATION**

22 **Q.** Please identify the opening testimonies and list issues raised by each party's Opening
23 Testimony which you will address in this section.

24 **A.** This section addresses:

- 25 • "Opening Testimony of Sam Harper and John Holler on behalf of California Large
26 Energy Consumers Association" filed February 13, 2026 in A. 25-05-009 discussing: (1)

⁷⁰ CalCCA at 33.

⁷¹ CalCCA at 26.

⁷² CalCCA at 78.

⁷³ CalCCA at 78-79.

1 the potential and conditions under which load growth can suppress rates, (2) the
2 recommendation that PG&E sequence and size investments based on accurate load
3 forecasts, and (3) the Rule 30 tariff proceeding and its role in removing uncertainty
4 around customer cost responsibility for transmission-level upgrades.

- 5 • The assertions made in the “Opening Testimony of Michael Colvin on Behalf of
6 Environmental Defense Fund” that ratepayers bear the risk of stranded grid investments
7 to serve large loads, such as data centers. I discuss the role of the present Rule 30
8 proceeding in dealing with such risks, as well as the existing interconnection Rule 15.
- 9 • TURN-16, “Electric, Gas and Common Plant, Testimony of Catherine E. Yap on behalf
10 of TURN,” filed February 13, 2026 in A.25-05-009, discussing (1) the exclusion of
11 ECNBIMA costs from 2024–2026 plant values pending reasonableness review, (2) the
12 legal basis for that exclusion under D.24-07-008 and D.23-11-069, and (3) the potential
13 downstream consequences for the 2027–2030 forecast and SB 410 compliance if TURN’s
14 recommendations are implemented. I provide an alternative recommendation for dealing
15 with this challenging situation.
- 16 • “Opening Testimony of Sam Harper and John Holler on behalf of California Large
17 Energy Consumers Association,” filed February 13, 2026, in A. 25-05-009, TURN-02
18 “Testimony of Jennifer Dowdell on behalf of TURN,” filed February 13, 2026, in A.25-
19 05-009,” and CA-04 collectively, discussing opposition to PG&E’s proposed New
20 Business Balancing Account.

21 **Q.** Do you agree with CLECA that load growth can bring about ratepayer savings, and if so,
22 what must the Commission do to realize that potential?

23 **A.** I agree on the premise that load growth in PG&E’s territory holds the potential to reduce
24 costs for all ratepayers; however, I also agree with CLECA that this benefit is by no means
25 guaranteed.⁷⁴ In my professional experience, cost deflation can result from higher rates of
26 utilization of grid assets and by reducing the “peakiness” of California’s load.

27 As CLECA notes, these savings will only materialize if the Commission subjects the costs to
28 serve that load to rigorous scrutiny and pursues least-cost procurement strategies for new
29 generation.⁷⁵ I recommend one material modification to CLECA’s proposal, that: “the
30 Commission require PG&E to sequence and size load growth and electrification-related
31 investments based on observed load growth and realistic demand forecasts”.⁷⁶ While I support
32 the intent, I would recommend replacing the word “realistic” with “up to date” so that the
33 proposal would be: “the Commission require PG&E to sequence and size load growth and
34 electrification-related investments based on observed load growth and the most up-to-date

⁷⁴ CLECA at 29.

⁷⁵ CLECA at 29.

⁷⁶ CLECA at 72.

1 demand forecasts.” Recently, the California Energy Commission’s (CEC) Integrated Energy
2 Policy Report (IEPR) forecast process has highlighted that significant and highly material
3 amounts of new load, based on pending energization work with energization online dates that are
4 verified, has been left out of the forecast used for resource adequacy and reliability planning.⁷⁷
5 Furthermore, I observe that the Commission has issued procurement orders for expensive new
6 generation using outdated (circa 2024) load forecasts, with zero justification as to why the
7 updated numbers were not used.⁷⁸ This very likely can and will lead to unnecessary costs from
8 over-procurement, or procurement that is too early for the actual load growth.

9 Critically, for CLEU’s members, it is essential that energization requests for non-speculative,
10 economically vital projects move forward on realistic timelines, which in many cases the utility
11 has already agreed to. Certain parties’ testimony lumps all non-transportation load growth
12 together⁷⁹ and implies that much of it is speculative. CLEU’s members would strongly disagree
13 that their projects to build new hospitals, research facilities, laboratories or data centers to
14 support emergency services are “uncertain” or speculative.

15 **Q.** Do you agree with CLECA's position on the Rule 30 tariff proceeding?

16 **A.** I agree with CLECA that the Rule 30 tariff proceeding, when finalized, will remove
17 uncertainty regarding whether customers will be stuck with transmission or distribution system
18 upgrade costs from new large loads.⁸⁰ As PG&E explains in its Rule 30 application, current
19 practice “requir[es] new transmission-level customers to provide advances and pay for actual
20 costs incurred for facilities necessary to interconnect the customer.”⁸¹ The 2025 interim decision
21 partially adopting Rule 30 interconnection processes simply allowed these to be processed in a
22 more efficient and consistent manner, vs the prior practice of each filing being done via an

⁷⁷ See “2025 IEPR Forecast - Updated Results” presented January 5, 2026, in the Demand Analysis Working Group meeting, available at https://www.energy.ca.gov/sites/default/files/2026-01/2026-01-05_DAWG_Mtg_Slides-Combined_ada.pdf.

⁷⁸ D. 26-02-057, "Decision Requiring 2029-2032 Electric Resource Procurement and Transmitting Portfolios for 2026-2027 Transmission Planning Process," issued March 5, 2026, in R.25-06-019 at 116–117.

⁷⁹ See, e.g., EDF at 6-7.

⁸⁰ CLECA at 72.

⁸¹ “Application Of Pacific Gas And Electric Company (U 39 E) For Approval Of Electric Rule No. 30 For Transmission-Level Retail Electric Service,” filed November 21, 2024, docketed as A. 24-11-007, at 2.

1 “exceptional case filing.”⁸² CLECA correctly observes that the Rule 30 proceeding ‘will likely
2 result in increased customer contributions should sufficiently reduce the uncertainty otherwise
3 entailed in forecasting for such customers.’⁸³

4 **Q.** How do you view EDF's position on ratepayers bearing the risk of “stranded” grid
5 investments to serve data center loads?

6 **A.** The present “Rule 15” interconnection process requires customers to fund the distribution
7 system upgrades needed to serve new large loads on the distribution grid, and both prior utility
8 practice and the interim Rule 30 provisions require customers interconnecting large-loads above
9 110kv to pre-pay transmission and sub-station costs.⁸⁴ Therefore, I note that EDF’s concerns
10 regarding stranded assets appear to reflect an oversight of the current cost-recovery framework,
11 which already requires significant upfront funding from the customer.

12 In CLEU’s experience, the financial risk of the load not materializing rests with the customer,
13 who would have paid for major upgrades that then don’t benefit them if their load doesn’t come
14 online, or if they pay for upgrades that are unnecessary based on their “real” vs expected overall
15 load and peak capacity. This upfront funding requirement effectively insulates general
16 ratepayers from the risk of stranded investments.

17 **Q. Do you agree with TURN’s identification of the problems with including ECNBIMA**
18 **costs in Phase One?**

19 **A.** I agree with TURN’s concerns regarding ECNBIMA costs but recommend a modified
20 approach to avoid adverse consequences for new business connections and beneficial
21 electrification. My understanding of the Electric Capacity and New Business Interim

⁸² D. 25-07-039 “Decision Partly Granting And Partly Denying Pacific Gas And Electric Company’s Motion For Interim Implementation Of Electric Rule Number 30,” issued July 24, 2025, in A. 24-11-007 at 48-50.

⁸³ CLECA at 72.

⁸⁴ PG&E Electric Rule No. 15, "Distribution Line Extensions," *available at* https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_15.pdf (governing customer cost responsibility for distribution-level interconnection); PG&E Electric Rule No. 30 (Interim), "Transmission-Level Retail Electric Service," *available at* https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_30.pdf (adopted on interim basis by D.25-07-039, "Decision Partly Granting and Partly Denying Pacific Gas and Electric Company's Motion for Interim Implementation of Electric Rule Number 30," issued July 24, 2025, in A.24-11-007)..

1 Memorandum Account (ECNBIMA) is that it was designed to track incremental capital costs
2 associated with energization and new service requests that exceed what was authorized in the prior
3 GRC.⁸⁵ SB 410,⁸⁶ passed in 2023, directs the Commission to ensure that electrical corporations
4 have “sufficient and timely recovery of costs” for energization. The bill defines electrification and
5 energization as

6 (a) “Electrification” means any new, expanded, or change in use of electricity
7 related to the policies described in Section 933, including, but not limited to, in
8 the industrial, commercial, agricultural, housing, or transportation sectors. (b)
9 “Energization” and “energize” mean connecting customers to the electrical
10 distribution grid and establishing adequate electrical distribution capacity or
11 upgrading electrical distribution or transmission capacity to provide electrical
12 service for a new customer, or to provide upgraded electrical service to an
13 existing customer. The determination of adequate electrical distribution capacity
14 includes consideration of future load. “Energization” and “energize” do not
15 include activities related to connecting electrical supply resources.⁸⁷

16 The Commission implemented SB 410 with D. 24-09-020, which established binding average
17 and maximum energization timelines.⁸⁸ The ECNBIMA exists because the 2023 GRC
18 authorization was demonstrably insufficient to meet the pace of energization demand
19 necessitated by beneficial electrification and load growth to serve California’s economy.⁸⁹ The
20 Commission recognized the insufficiency of the 2023 GRC authorization in D.24-07-008 and
21 again in D.25-08-036.⁹⁰ As of year-end 2024, PG&E had tracked approximately \$582 million in
22 ECNBIMA-eligible incremental capital expenditures above the 2023 GRC baseline.⁹¹ The
23 independent third-party auditor’s biannual reports under Public Utilities Code Section 938
24 provide ongoing evidence of PG&E’s energization workload and spending trajectory.⁹² These
25 are the inputs that should drive the 2027-2030 forecast, not stale estimates that were developed

⁸⁵ Electric Preliminary Statement Part KH, Electric Capacity and New Business Interim Memorandum Account, available at https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_KH.pdf.

⁸⁶ Senate Bill (SB) 410, Becker, Chapter 394, Statutes of 2023. Public Utilities Code Sections 930-939.5.

⁸⁷ *Id.*

⁸⁸ *Id.*

⁸⁹ D. 24-07-008, "Decision Authorizing a Ratemaking Mechanism for Energization Projects Pursuant to Senate Bill 410," issued July 16, 2024, in A.21-06-021; D. 25-08-036, "Decision Resolving Pacific Gas and Electric Company's Motion to Revise Its 2025 and 2026 Energization Cost Caps," issued September 4, 2025, in R.24-01-018.

⁹⁰ *See id.* *See also* PG&E Electric Preliminary Statement Part KH, Sheet 5 (Revised Cal. P.U.C. Sheet No. 60402-E, filed via Advice 7724-E implementing D.25-08-036), Table 2.

⁹¹ *See id.* *See also* Attachment C to TURN-16 (PG&E Response to TURN-40, Q.2.a).

⁹² Pub. Util. Code § 938(a)(3)–(5).

1 under a completely different paradigm. The 2023 GRC authorization must not be used as
2 evidence of baseline energization need in this GRC. Three years of recorded and forecast data
3 now demonstrate that energization spending at levels substantially above the old baseline is not
4 an anomaly, but rather is a sustained trend driven by application volumes, statutory mandates,
5 and Commission-ordered timelines.

6 Because the general rate case cycle operates on a four-year horizon, rates set in this
7 proceeding will govern through 2030. If the 2027-2030 forecast does not reflect the demonstrated
8 pace of energization work, the consequences would include: dramatic growth in the energization
9 backlog, delays in connecting new residential and commercial customers, impediments to
10 electrification and economic development, and a failure to meet the binding timelines the
11 Commission itself adopted in D.24-09-020; the very outcomes SB 410 was enacted to prevent.

12 Catherine Yap's testimony for TURN argues that PG&E must exclude from its electric
13 distribution plant figures the capital expenditures recorded in, or forecast for, the ECNBIMA for
14 the years 2024 through 2026.⁹³ Yap's proposed remedy is specific: the adopted 2024-2025
15 electric distribution plant values should be reduced by the ECNBIMA capital expenditures
16 recorded for those years, and she recommends that the adopted 2026 forecast be reduced by the
17 best estimate of 2026 ECNBIMA capital expenditures.⁹⁴

18 In PG&E's Results of Operations model, recorded and forecast capital expenditures for
19 2024-2026 are converted to capital additions and included in electric distribution plant-in-
20 service.⁹⁵ These plant values establish the starting rate base from which the test year and post-
21 test-year calculations derive. When ECNBIMA capital (which for 2024 alone amounted to
22 approximately \$582 million in tracked eligible expenditures) is removed from the 2024-2026 plant
23 figures, the resulting base-period plant values drop substantially. That lower starting point
24 cascades forward through the model.

25 Therefore, while TURN's testimony is focused on the correct treatment of 2024-2026
26 plant values (and does not make an argument about the appropriate level of the 2027-2030

⁹³ "Electric, Gas and Common Plant, Testimony of Catherine E. Yap on behalf of TURN," filed February 13, 2026, in A.25-05-009 (TURN-16) at 1-3.

⁹⁴ TURN-16 at 4.

⁹⁵ PG&E Exhibit (PG&E-10), "Results of Operations," filed May 15, 2025, in A.25-05-009.

1 forecast) adopting the proposed adjustment has mechanical implications for the forward-looking
2 authorization that extends beyond the plant question TURN addresses.

3 **Q. What is your assessment of TURN’s arguments regarding the inclusion of ECNBIMA**
4 **figures in the rate base, and do you have an alternative recommendation?**

5 **A.** I agree with TURN’s core premise regarding regulatory practice, and the substance of its
6 proposed adjustment to recorded and forecast plant values for 2024-2026 is valid. TURN cites the
7 Commission’s finding in D.23-11-069 that “for amounts recorded in memorandum accounts, the
8 Commission must first review those costs for reasonableness, and to include costs in rate base they
9 must be both used and useful as well as prudently incurred.”⁹⁶ TURN notes that the Commission
10 made similar findings in D.25-09-030 regarding Southern California Edison’s TY 2025 GRC.⁹⁷
11 PG&E has appropriately applied this principle to exclude from its plant figures the amounts
12 recorded in other memorandum accounts that are pending before the Commission in separate
13 applications.⁹⁸ The same principle applies to the ECNBIMA.

14 I agree generally with TURN’s analysis regarding memorandum account costs and rate
15 base. Decision 24-07-008, Ordering Paragraph 1, expressly conditions ECNBIMA cost recovery
16 on reasonableness review in the test year (TY) 2027 GRC.⁹⁹ The Assigned Commissioner’s
17 Scoping Memo in this proceeding has established Track 3, commencing in 2027, for that
18 purpose.¹⁰⁰ But, until Track 3 concludes, the Commission will not have made a final determination
19 that the recorded ECNBIMA expenditures to satisfy the just and reasonable standard of Public
20 Utilities Code Section 451.

21 TURN’s argument rests on a well-established principle of California utility regulation: that
22 costs recorded in memorandum accounts must undergo reasonableness review before inclusion in
23 rate base. However, adopting TURN’s proposed adjustment without addressing its consequences
24 would create a significant new problem not addressed by TURN’s testimony, which would have
25 cascading consequences for energization for many years to come.

⁹⁶ TURN-16 at 3.

⁹⁷ TURN-16 at 3.

⁹⁸ TURN-16 at 1-2.

⁹⁹ Decision 24-07-008 at 91.

¹⁰⁰ Assigned Commissioner's Scoping Memo and Ruling, issued July 31, 2025, in A.25-05-009 at 17.

1 **Q. What are the potential unintended consequences if TURN’s recommendation were**
2 **implemented without modification?**

3 **A.** If the Commission adjusts the 2024-2026 plant values downward per TURN’s
4 recommendation but takes no further action, the practical effect would be a 2027-2030
5 authorization built on an artificially low foundation. In the “Results of Operations” model plant-
6 in-service values for 2024-2026 serve as the foundation from which the 2027-2030 forecast is
7 built, so the exclusion of ECNBIMA capital from the base period would mechanically depress the
8 forward-looking forecast in a manner that is disconnected from the demonstrated level of
9 energization need.

10 Therefore, I recommend that the Commission separately and independently ensure (or
11 require PG&E to ensure) that the 2027-2030 forecast is set at a level that reflects the feasible pace
12 of energization activity, based on observations regarding what is achievable, regardless of how the
13 2024-2026 plant values are ultimately treated. While TURN does not argue that the 2027-2030
14 forecast should be set at a level that excludes ECNBIMA-era energization activity, that would be
15 the practical outcome. Therefore, I recommend that the Commission independently ensure that
16 the 2027-2030 forecast reflects the demonstrated, and approved energization need.

17 The Commission can adopt TURN’s plant adjustment and protect the integrity of the
18 forward-looking forecast through a two-part approach: first, accept the substance of TURN’s
19 recommendation for 2024-2026 plant-in-service. Recorded ECNBIMA capital additions for
20 2024-2025, and the best estimate of 2026 ECNBIMA capital expenditures, should be excluded
21 from the electric distribution plant values underlying the TY 2027 rate base. This preserves the
22 Commission’s established precedent regarding memorandum account costs and ensures that
23 PG&E does not earn a return on unreviewed assets. Upon completion of Track 3, costs found to
24 be just and reasonable would be incorporated into rate base with appropriate prospective
25 treatment.

26 Second, set the 2027-2030 electric distribution capital expenditure forecast at levels that
27 reflect demonstrated energization need, independent of the 2024-2026 plant adjustment. The
28 evidentiary record (including three years of ECNBIMA-eligible spending data, current and
29 projected application volumes, the Commission’s adopted energization timelines, and the
30 independent auditor’s reports) provides a robust basis for establishing the forward-looking

1 authorization. The Commission should evaluate the reasonableness of the 2027-2030 forecast on
2 its own merits in Track 1 of this proceeding, without treating the exclusion of 2024-2026
3 ECNBIMA costs from rate base as an implicit ceiling on what the forward-looking authorization
4 should be.

5 My recommended modified approach would still provide full effect to the reasonableness
6 review requirement that TURN asserts is necessary, while ensuring that ratepayers are not paying
7 a return on unvetted assets, and avoiding the unintended consequence of setting a four-year
8 energization authorization at a level that is inconsistent with SB 410, D.24-09-020, and the
9 demonstrated needs of PG&E's service territory.

10 **Q. What is CLEU's position on the New Business Balancing Account vis a vis CLECA,**
11 **TURN, and Cal Advocates opposition to the NBBA, and how does CLEU propose to**
12 **account for new business costs in the GRC?**

13 **A.** CLEU believes that a forecast which includes new business capital expenses is a more
14 appropriate approach to ratemaking as opposed to PG&E's balancing account proposal. We
15 align with CLECA, TURN, and Cal Advocates in opposing the use of a balancing account for
16 new business connections, and agree with CLECA that "New Business costs can and should be
17 reasonably forecasted and budgeted in the GRC" and the Commission should therefore "reject
18 the proposal to create the New Business Balancing Account."¹⁰¹ As Finklestein's testimony for
19 TURN points out, PG&E's own justification for the New Business Balancing Account (NBBA)
20 undercuts the request.¹⁰² TURN indicates that PG&E says it needs the NBBA because customer
21 energization demand is uncertain and beyond its control.¹⁰³ But Finkelstein notes that PG&E
22 already proposed to discontinue two other memorandum accounts (the ECNBIMA and Assembly
23 Bill 841 Memorandum Account (AB841MA)) on the grounds that PG&E "is able to develop a
24 reasonable forecast of program costs" – the exact opposite argument.¹⁰⁴ CLEU's proposal – to
25 exclude ECNBIMA from plant values but forecast future expenditures based on demonstrated
26 energization need – are aligned with the principle that in a forecast-based TY ratemaking model,
27 costs that can be forecast must be included in the GRC revenue requirements for regulatory and

¹⁰¹ CLECA at 31.

¹⁰² TURN-18 at 56-57.

¹⁰³ TURN-18 at 56.

¹⁰⁴ TURN-18, p. 38, fn. 82.

1 intervenor scrutiny. As Dowdell’s testimony for TURN argues, “since PG&E operates on
2 forecasted test year with attrition, costs of operations that can be reasonably forecast should be
3 explicitly included in PG&E's GRC request for approval or disallowance by the Commission.”¹⁰⁵

4 Cal Advocates witnesses Hieta and Myers align with CLECA and TURN, recommending that
5 the Commission should deny PG&E's proposal to create the NBBA.¹⁰⁶ Cal Advocates also
6 recommends the Commission deny PG&E's request to use the alternative forecast for 2027–
7 2030.¹⁰⁷ Cal Advocates points out that PG&E's alternative forecast assumed the Commission
8 had not granted PG&E's SB 410 Motion to increase 2025–2026 capital cost caps — but the
9 Commission actually did grant that motion in D.25-08-036 on August 28, 2025.¹⁰⁸ As Cal
10 Advocates notes in its testimony, PG&E itself conceded that if the SB 410 Motion was granted,
11 its alternative (higher) forecast would decrease.¹⁰⁹ These are the cost cap increases that we
12 discussed in the ECNBIMA section above. CLEU’s recommendation is not contrary to Cal
13 Advocates’ argument: we argue that PG&E’s forecast for TY 2027 and the attrition formula
14 applied thereafter should be recalibrated to reflect the Commission’s actual authorizations and
15 the demonstrated trajectory of energization demand, rather than relying on either a mechanically
16 suppressed base or an alternative scenario premised on outdated assumptions. Specifically, the
17 forecast should incorporate (1) the Commission-approved ECNBIMA cost cap increases in D.25-
18 08-036, (2) the observed level of recorded and forecast ECNBIMA-eligible spending across
19 2024–2026, and (3) the workload and timing requirements established pursuant to SB 410 and
20 implemented in D.24-09-020.

21 Under this approach, CLEU’s recommendation is fully consistent with the positions of TURN
22 and Cal Advocates opposing the NBBA. Like those parties, CLEU rejects the use of a balancing
23 account to manage costs that can be reasonably forecast and instead supports incorporation of
24 those costs into the test year revenue requirement, subject to full Commission review. At the
25 same time, CLEU’s proposal addresses a gap left by those positions: it ensures that the forecast
26 itself is set at a level that reflects actual, observed energization demand, rather than being

¹⁰⁵ TURN-02, at 11.

¹⁰⁶ See CA-04 at 5, 20. See also CLECA at 31 and TURN-18 at 56.

¹⁰⁷ CA-04 at 21.

¹⁰⁸ D.25-08-036 at 79.

¹⁰⁹ CA-04 at 20.

1 inadvertently constrained by the exclusion of ECNBIMA plant from the base years or by reliance
2 on a counterfactual forecast that no longer reflects Commission-approved policy.

3 **X. CONCLUSION**

4 **Q.** Does this conclude your testimony?

5 **A.** Yes, this concludes my testimony. I commend all of the parties who submitted testimony in
6 Phase 1, it was my pleasure to review and comment upon their thoughtful analysis and I hope
7 that CLEU's rebuttal testimony will shed light on areas of shared concern, ways to implement
8 modified party proposals, and overall will strengthen the record in this proceeding.

9

1 **STATEMENT OF QUALIFICATIONS OF MEREDITH L. ALEXANDER (Younghein)**

2 **Q.** I hold a Juris Doctor and a Certificate in Natural Resources Law from the Northwestern
3 School of Law at Lewis & Clark College. I graduated Magna Cum Laude with Honors in
4 Environmental Policy and Political Science from Newcomb College, Tulane University. I
5 am admitted to the Colorado state Bar. While in law school, I clerked for the Bonneville
6 Power Administration, where I was trained in cost-of-service ratemaking, and supported
7 transmission and electric rate cases. During my clerkship, I wrote briefs on transmission
8 system maintenance issues and safety, among other issues. I worked at the California Public
9 Utilities Commission from 2012-2016, and was a Senior Regulatory Analyst on the Long-
10 Term Planning and Resource Adequacy team for two years. During this time I served as the
11 Energy Division’s liaison to the CAISO and published reports on reliability and renewables
12 integration. While a Senior Analyst at the CPUC I also attended a week long “rate school”
13 to learn the fundamentals of utility accounting and ratemaking. From 2019-2022 I served as
14 the Director for State Policy at CALSTART, a national 501c3. During this time, I
15 participated in rate cases and rate design proceedings in various states, including New York,
16 Maryland, North Carolina and California on behalf of CALSTART. Since 2022, I have been
17 a consultant on energy policy issues to a wide variety of clients, including Fortune 100
18 companies, NGOs and technology manufacturers. My work recently has focused on electric
19 grid reliability and procurement. I am currently the Principal Policy Consultant and Acting
20 Executive Director of CLEU. In this capacity, I possess confidential and current information
21 regarding our member companies’ and institutions’ electricity use and electricity costs, as
22 well as their plans for growth and electrification.