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PACIFIC GAS AND ELECTRIC COMPANY

2023 GENERAL RATE CASE

EXHIBIT (PG&E-11)

POST TEST-YEAR RATEMAKING

**[INCLUDES ERRATA THROUGH FEBRUARY 28, 2022
AND FEBRUARY 28, 2022 SUPPLEMENTAL TESTIMONY]**



PACIFIC GAS AND ELECTRIC COMPANY
2023 GENERAL RATE CASE
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POST TEST-YEAR RATEMAKING

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
POST TEST-YEAR RATEMAKING PROPOSAL
[INCLUDES FEBRUARY 28, 2022 ERRATA AND
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PACIFIC GAS AND ELECTRIC COMPANY
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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **CHAPTER 1**
3 **POST TEST-YEAR RATEMAKING PROPOSAL**

4 **A. Introduction**

5 **1. Scope and Purpose**

6 The purpose of this chapter is to request that the California Public
7 Utilities Commission (CPUC or Commission) approve Pacific Gas and
8 Electric Company’s (PG&E or the Company or the Utility) proposal for a
9 Post Test-Year (PTY) Ratemaking (PTYR) mechanism that will be used to
10 adjust authorized revenue requirements in 2024, 2025, and 2026.
11 Commission adoption of sufficient PTY attrition adjustments for 2024, 2025,
12 and 2026 is necessary to provide PG&E with the funds it needs to provide
13 safe and reliable service to customers, while offering PG&E a fair
14 opportunity to earn the rate of return found reasonable by this Commission.
15 A critical element of a fundamentally sound attrition mechanism is the
16 recognition that expense escalation and growth in rate base are separate
17 and distinct drivers for PTY cost growth and should be reflected in the
18 attrition mechanism accordingly. This follows directly from the
19 Commission’s reasoning and conclusions adopted in previous adjudicated
20 rate case proceedings including PG&E’s 2014 General Rate Case (GRC)
21 (Decision (D.) 14-08-032).

22 **2. Summary of Request**

23 PG&E requests that the Commission adopt a PTYR mechanism that
24 escalates the majority of adopted test year (TY) expense amounts and
25 models capital revenue requirement growth based on adopted TY plant
26 additions. This separate treatment of expense growth and capital revenue
27 requirement growth is necessary because the fundamental drivers for each
28 are different.

29 PG&E emphasizes the capital aspect of its PTYR request because the
30 principal mechanics of PTY cost changes have not always been fully
31 understood or recognized by intervenors who often suggest that a utility
32 should receive PTYR increases that solely reflect growth in the Consumer
33 Price Index (CPI) or some other measure of inflation. While PG&E agrees

1 TY revenue requirement escalation (at appropriate rates) makes sense for
2 setting funding levels for utility *expenses*, such as wages, materials, and
3 health care costs (and we continue to propose this as an element of PTYR),
4 escalation is not a prudent method for determining *capital revenue*
5 *requirement increases* during the PTY period. Capital revenue requirement
6 changes are determined almost entirely by the relationship between capital
7 additions, depreciation and levels of tax repair eligibility. When capital
8 additions exceed depreciation and tax repair deduction, rate base and the
9 related capital revenue requirement components increase. This happens
10 irrespective of inflation.

11 To illustrate, PG&E's average 2024, 2025, and 2026 capital
12 expenditures are forecasted to be roughly \$9.9 billion¹ per year offset by
13 depreciation of roughly \$4.6 billion² per year. This means that weighted
14 average rate base is growing by roughly \$4.5 billion³ per year or 9 percent.
15 CPI growth has no bearing on that percentage growth in rate base and as a
16 result, an attrition increase based on CPI, which is forecasted to be roughly
17 2.4 percent,⁴ would severely under-fund PG&E's operations.

18 Figure 1-1 shows differences by revenue requirement component
19 between expected 2024, 2025, and 2026 cost growth under PG&E's
20 proposed cost-of-service attrition model and CPI. As is graphically evident,
21 the largest difference by far is in the area of capital costs. This immense
22 deficiency, most notably with respect to capital, would require significant
23 PTY spending reductions, severely under-funding PG&E's operations and
24 adversely impacting its ability to provide safe and reliable service.

25 Due to the closure of Diablo Canyon Power Plant (DCPP), the operating
26 and maintenance (O&M) expense for DCPP has been shown separately in
27 Figure 1-1. PG&E has proposed for discrete capital and expense
28 adjustments during the attrition years for DCPP to reflect the lower
29 expenses and capital expenditures as described further below.

1 Exhibit (PG&E-10), Ch. 10, WP Table 10-4.

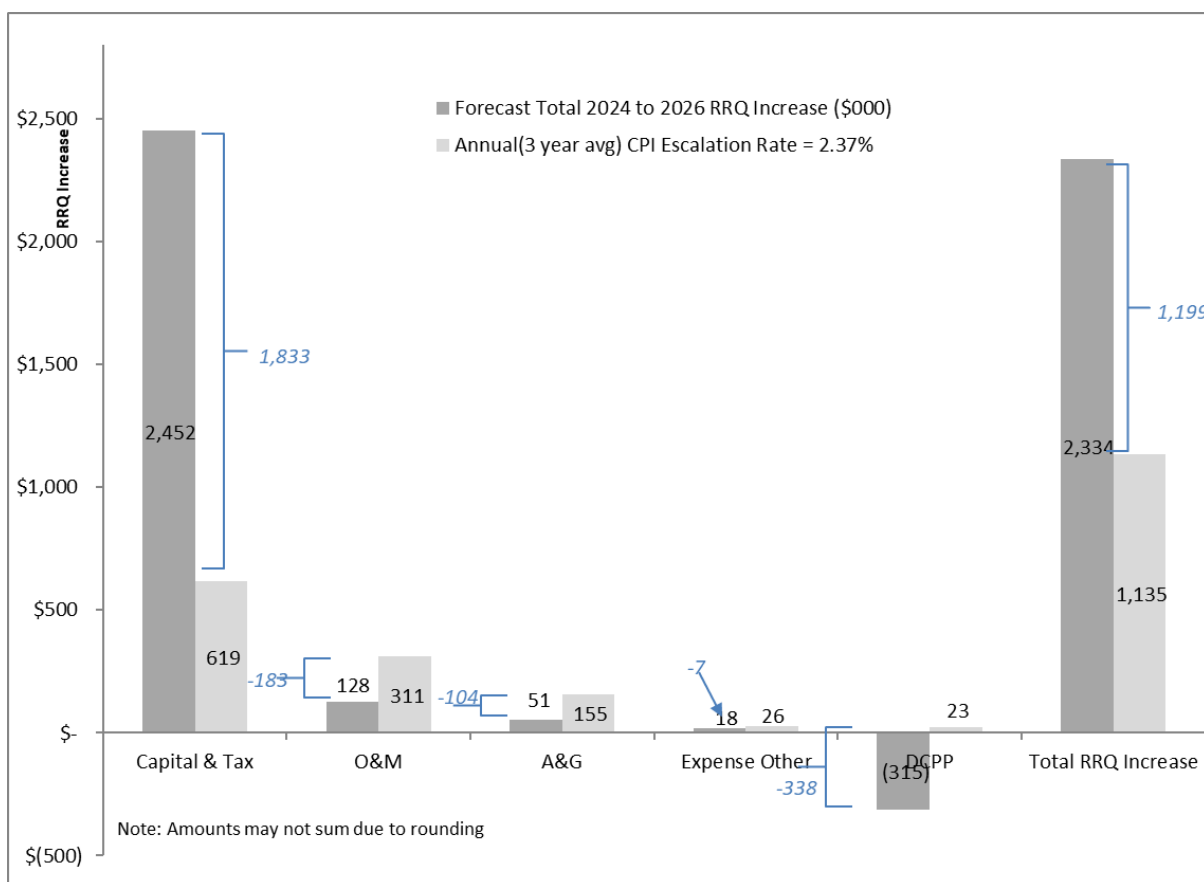
2 Exhibit (PG&E-11), WP 2-3, Table 2-22.

3 Exhibit (PG&E-11), p. 3-2, Table 3-1.

4 CPI All-Urban US (IHS Markit, Q1 2020).

1 Furthermore, the O&M expense, in Figure 1-1, reflects PG&E’s attrition
2 request amount that is lower than CPI due to forecast cost reductions for
3 Vegetation Management (VM) and Enhanced Powerline Safety Settings
4 (EPSS) programs during the PTY periods. These reductions reflect PG&E’s
5 commitment to reducing its expense costs commensurate with PG&E’s
6 increased capital expenditure requests in system hardening undergrounding
7 work in the high fire threat district areas.

FIGURE 1-1
2024-2026 TOTAL GRC REVENUE REQUIREMENT INCREASES COMPARISON WITH CPI
(MILLIONS OF DOLLARS)



8 For the capital component of the attrition proposal, as discussed in
9 Chapter 3 of this exhibit, PG&E proposes to base capital additions on TY
10 plant additions plus escalation, except for capital additions for gas storage,
11 nuclear operations, hydroelectric generation (hydro), and corporate real
12 estate, which are based on “bottom-up” capital forecasts. As described in
13 PG&E’s supplemental testimony served on February 25, 2022. PG&E has

1 updated the forecast to reflect the Utility's proposal to underground
2 additional miles of electric distribution powerlines to reduce wildfire risk.
3 Due to this change, PG&E is now recommending that capital attrition
4 spending related to system hardening and underground also be based on
5 the revised "bottom-up" capital forecast, rather than simple escalation. This
6 ratemaking proposal responds to intervenor concerns that a PTYR
7 mechanism should be simple.

8 For the operating expense component of the attrition proposal, PG&E
9 requests that utility expenses (e.g., labor, materials, and health care costs)
10 be adjusted to reflect the appropriate measures of cost escalation, except
11 for the following seven areas:

- 12 • Gas storage costs;
- 13 • VM costs;
- 14 • Declining expenses associated with the planned closure of DCPD;
- 15 • Time-of-use (TOU) mandatory transitions to revised TOU periods and
16 Peak-Day Pricing (PDP) Event Hour Revision;
- 17 • Healthcare and other Administrative and General (A&G) corporate
18 items;
- 19 • Wildfire excess liability insurance; and
- 20 • The newly implemented EPSS program.

21 Since PG&E's proposed method for estimating PTY cost-of-service
22 increases does not include increased operating costs related to serving
23 additional customers, and PG&E is not able to generate additional revenue
24 through higher sales, there is an implicit productivity target included in
25 PG&E's proposal.

26 Finally, PG&E also proposes to continue the Z-factor mechanism, which
27 includes TY events, including a \$10 million deductible amount per event.⁵

28 This exhibit addresses PTY revenue requirements for all lines of
29 business (LOB) covered in this proceeding including electric and gas
30 distribution, electric generation, gas transmission and storage (GT&S).
31 Chapter 1 outlines the proposed mechanism, Chapter 2 provides additional
32 details and estimated revenue requirement increases for 2024, 2025 and

⁵ D.20-12-005, p. 409, Conclusions of Law 130, 131, and 132.

1 2026 based on PG&E's TY forecast, and Chapter 3 highlights projected
2 growth in rate base and the related capital costs.

3 **3. Organization of the Remainder of This Chapter**

4 The remainder of this chapter is organized as follows:

- 5 • Section B – Background on Previous Commission Attrition Decisions;
- 6 • Section C – Summary Description of Attrition Mechanism;
- 7 • Section D – PG&E Needs Attrition Increases in 2024, 2025, and 2026;
- 8 • Section E – PG&E's Attrition Proposal Is Reasonable for All Parties; and
- 9 • Section F – Implementation of PTYR.

10 **B. Background on Previous Commission Attrition Decisions**

11 Over the years, the Commission has issued resolutions and decisions
12 providing guidance as to the timing and content of rate cases and the
13 mechanisms to be used to request revenue adjustments to recover various costs
14 (rate case plan decisions). In D.20-01-002, the CPUC adopted a risk-informed
15 decision-making framework for inclusion in the rate case plan and revised the
16 standard procedural schedule. The rate case plan replaced the schedule
17 adopted in D.14-12-025 and ordered the utilities to follow a 4-year cycle based
18 on a forecast TY revenue requirement, followed by three attrition years. The
19 revenue balancing accounts assure that the Utility's revenues match the
20 revenue requirements authorized by the Commission.

21 The Commission's earliest decisions establishing a rate case plan sought to
22 set a schedule that allowed for the timely processing of rate cases to avoid one
23 case being filed before the previous case was decided. The Commission initially
24 set a schedule that allowed energy utilities to file GRC applications every other
25 year. This was later extended to every third year (PG&E's 1999, 2003, and
26 2007 GRCs were on 4-year intervals). Shortly after establishing the
27 every-other-year schedule, the Commission was faced with the issue of how to
28 recognize cost increases in the "off years."

29 In its decision in PG&E's 1980 GRC, the Commission established the
30 Electric Revenue Adjustment Mechanism which was envisioned to automatically
31 align the revenues billed to customers with the revenue requirements authorized
32 by the Commission (primarily to make revenues independent of sales and
33 remove the financial disincentive associated with promoting conservation

1 activities) and, at the same time, formalized an Attrition Rate Adjustment (ARA)
 2 mechanism. In authorizing the ARA, the Commission recognized the Utility
 3 would no longer be able to recover through increased sales the drivers in
 4 cost-of-service increases between GRCs: escalation of operating expenses,
 5 increases in the embedded cost of debt and preferred stock, *and growth in rate*
 6 *base.*⁶ The Commission has since addressed the effect of variation in the
 7 elements of Cost of Capital (COC) through the COC proceeding. However, the
 8 need for attrition adjustments to offset escalation of expenses and rate base
 9 growth through a PTY ratemaking mechanism continues.

10 Through various decisions, the Commission has also acknowledged that
 11 there are different drivers for the capital and expense components of attrition
 12 and therefore each need to be addressed separately in order to determine
 13 reasonable expectations for PTY cost-of-service growth. In PG&E's 2014 GRC
 14 decision, the Commission explicitly acknowledged the need for separate
 15 expense and capital components of attrition:

16 We adopt a two-part mechanism to capture distinctions driving attrition
 17 increases (a) for expenses versus (b) for capital expenditures. We decline
 18 to adopt DRA's primary proposal to set post-test-year revenue increases
 19 simply based on a single index, with no distinction between expenses
 20 versus capital additions. While applying a single index, as proposed by
 21 DRA, offers simplicity, we conclude that such an approach fails to
 22 adequately capture the distinctions between expense and capital
 23 expenditure attrition.

24 The Commission also adopted a separate capital attrition increase based on
 25 escalated TY adopted additions in Southern California Edison Company's (SCE)
 26 2012 GRC (D.12-11-051) and 2015 GRC (D.15-11-021). Sempra Energy
 27 similarly requested a PTYR mechanism in their 2016⁷ and 2019⁸ GRCs that
 28 separately calculates capital revenue requirement growth based on forecasted
 29 capital additions.

6 D.93887, 1981 Cal. PUC LEXIS 1279, *322, Findings and Conclusions 26.

7 While D.16-06-054 adopted a settlement containing a specific attrition rate, Office of Ratepayer Advocates (ORA) did not oppose a PTY ratemaking mechanism similar to Sempra's proposals to include separate escalation factors for operations and maintenance and capital-related costs. See A.14-11-003/004, Exhibit ORA-23, p. 4, lines 7-28.

8 D.19-09-051, pp.706-708.

1 C. Summary Description of Attrition Proposal

2 The attrition mechanism PG&E proposes would allow for pre-determined
3 increases in the various components of PG&E's adopted cost-of-service revenue
4 requirement based on the forecasting methodology appropriate for each
5 component.

6 For expense, PG&E proposes that an appropriate escalation rate be applied
7 to TY adopted amounts based on the best source available to project cost
8 escalation in each expense category. The specific escalation rates are
9 described in Chapter 2. These escalation rates would be set upon a final
10 Commission decision in this proceeding and would establish fixed increases in
11 the expense component of PG&E's adopted revenue requirement.

12 Under PG&E's proposal, there are seven exceptions to simple escalation of
13 adopted TY expense amounts:

- 14 1) Gas storage costs presented in Exhibit (PG&E-3), Chapter 7;
- 15 2) VM expense presented in Exhibit (PG&E-4), Chapter 9;
- 16 3) Declining expenses associated with the planned closure of DCPD presented
17 in Exhibit (PG&E-5), Chapter 3;
- 18 4) TOU mandatory transitions to revised TOU periods and PDP Event Hour
19 Revision costs presented in Exhibit (PG&E-6), Chapter 3;
- 20 5) Healthcare and other A&G corporate items due to DCPD retirement as
21 discussed in Exhibit (PG&E-7), Chapter 1A; Exhibit (PG&E-8), Chapters 4
22 and 5; and Exhibit (PG&E-9), Chapter 3;
- 23 6) Wildfire excess liability insurance presented in Exhibit (PG&E-9), Chapter 3;
24 and
- 25 7) EPSS expense as described in Exhibit (PG&E-4), Chapter 4.6,
26 supplemental testimony that was served on February 25, 2022.

27 As discussed in Chapter 2, these activities are not expected to follow a
28 normal pattern of escalation over the 2023 GRC rate case cycle; and therefore,
29 PG&E proposes specific adjustments for these costs in 2024, 2025, and 2026.

30 For capital, PG&E proposes that adopted capital revenue requirement
31 growth in the attrition years be based on rate base growth resulting from
32 adopted TY plant additions plus escalation, forecasted depreciation, and the
33 estimated change in deferred tax liabilities. This follows the approach adopted
34 by the Commission in SCE's 2012 and 2015 GRCs. Escalation of adopted TY

1 capital additions would be based on IHS Markit Utility Capital Cost escalation
2 factors as described in Exhibit (PG&E-12), Chapter 3, and would be locked-in
3 upon a final Commission decision in this proceeding.

4 Under PG&E's proposal, there are five exceptions to simple escalation of
5 adopted TY capital additions:

- 6 1) Gas storage;
- 7 2) Nuclear generation;
- 8 3) Hydro generation;
- 9 4) Corporate real estate; and
- 10 5) Electric distribution system hardening and the community rebuild program,
11 as described in supplemental testimonies that was served on February 25,
12 2022.

13 These exceptions are supported by "bottom-up" capital forecasts provided in
14 Exhibit (PG&E-3), Chapter 7, Exhibit (PG&E-5), Chapter 3, Exhibit (PG&E-5),
15 Chapter 4, Exhibit (PG&E-7), Chapter 5, and Exhibit (PG&E-4), Chapters 4.3
16 and Chapter 23, respectively. Additionally, PG&E has prepared a bottom-up
17 forecast for all of its PTY capital expenditures, which supports PG&E's proposal
18 to use simple escalation for the majority of PTY capital additions.

19 PG&E also proposes to continue the Z-factor mechanism authorized in the
20 2020 GRC D.20-12-005 to record costs associated with exogenous and
21 unforeseen events in TY and PTYs that are largely beyond PG&E's control but
22 have material impacts on costs. Each Z-factor event will only include costs in
23 excess of a one-time \$10 million deductible per event. PG&E proposes to
24 modify the Z-factor mechanism procedure to request for recovery of the revenue
25 requirement associated with the Z-factor events in an advice letter filing instead
26 of an application, consistent with SCE's process.

27 **D. PG&E Needs Attrition Revenue Adjustments in 2024, 2025, and 2026**

28 **1. PG&E's Plant Additions in Excess of Depreciation Is the Primary Driver** 29 **of the Need for Attrition Revenue Requirement Increases and Exists** 30 **Regardless of Inflation**

31 Rate base growth is the principal driver of the need for attrition year
32 increases. PG&E has invested and continues to invest substantial amounts
33 to upgrade and replace infrastructure needed to provide safe and reliable

1 service. To the extent these capital additions exceed depreciation of
2 existing facilities, rate base is growing, and PG&E must raise debt and
3 equity from investors to fund this growth—which increases PG&E’s financing
4 costs. Growth in PG&E’s plant balance also creates additional depreciation
5 expense. As previously explained, these changes in capital costs are not a
6 function of inflation and therefore are not expected to track with changes
7 in CPI.

8 PG&E’s forecasted rate base growth is presented in Chapter 3 of this
9 exhibit and for 2024 is \$3,250 million for electric distribution, \$739 million for
10 gas distribution, \$892 million for GT&S, and a reduction of \$224 million for
11 electric generation. In 2025, rate base growth is forecasted to be
12 \$3,825 million for electric distribution, \$694 million for gas distribution,
13 \$694 million for GT&S, and a reduction of \$823 million for electric
14 generation. In 2026, rate base growth is forecasted to be \$4,080 million for
15 electric distribution, \$643 million for gas distribution, \$614 million for GT&S
16 and a reduction of \$803 million for electric generation. The revenue
17 requirement increases associated with this growth in capital investment are
18 presented in Table 2-3 of Chapter 2 (line 45) and are estimated to be
19 \$1,018 million in 2024, \$755 million in 2025, and \$561 million in 2026.

20 **2. Cost Escalation Is a Secondary Driver of the Need for Attrition** 21 **Increases That Needs to Be Reflected in the Attrition Mechanism**

22 When the attrition mechanism was first established, the level of inflation
23 in the general economy was relatively high: PG&E’s first attrition AL filing at
24 the end of 1982 used escalation rates of 7.3 percent for labor and
25 5.6 percent for non-labor expenses. Although the general level of inflation
26 has declined from the highs of the late 1970s and early 1980s, PG&E still
27 faces cost-escalation related to the use of labor and resources necessary to
28 provide utility service. In order to allow PG&E a fair opportunity to earn the
29 rate of return found reasonable by this Commission, authorized revenues
30 must be adjusted to reflect reasonable expectations for wage growth and
31 escalation in the cost of goods and services. The revenue requirement
32 changes associated with expense escalation are presented in Table 2-3
33 of Chapter 2 (line 39) and are estimated to be an increase of \$91 million in
34 2024, and reductions of \$78 million and \$130 million in 2025 and 2026,

1 respectively. Excluding DCP's O&M expenses, the revenue requirement
2 increases associated with expense escalation are estimated to be
3 \$89 million in 2024, \$70 million in 2025, and \$37 million in 2026.⁹

4 **3. Certain Capital and Operating Expenses Are Not Expected to Follow a**
5 **Normal Pattern Over the Rate Case Cycle, Resulting in the Other Cost**
6 **Changes That Should Be Captured in the Attrition Mechanism**

7 The scale of PG&E's capital and operating activities is generally
8 consistent year-over-year (YOY), such that escalation applied to TY capital
9 and operating expense levels provides a reasonable estimate of PTY capital
10 and expense growth (assuming that the increased cost to serve new
11 customers is offset by productivity improvements). Certain capital and
12 operating activities are not expected to follow that normal pattern of
13 escalation, however, and where significant discrete fluctuations are
14 expected, attrition revenue adjustments need to be made in order to align
15 revenues with expected cost-of-service changes. In the interest of achieving
16 a simple mechanism, such adjustments should be limited to situations where
17 the change in capital and operating activities is assured and the impact on
18 PG&E's costs can be reasonably estimated.

19 **E. PG&E's Attrition Proposal Is Reasonable for All Parties**

20 **1. The Proposed Adjustments Correlate With Reasonable Expectations**
21 **for Cost-of-Service Growth, Resulting in a Consistent Level of Work**
22 **That Can Be Completed Over the Rate Case Period**

23 An attrition adjustment should provide utilities a reasonable opportunity
24 to recover growth in their costs between rate cases and earn the authorized
25 rate of return. PG&E's proposed attrition increases incorporate the
26 two primary drivers of change in a utility's cost of service: the increase in
27 rate base and capital-related costs that result from capital expenditures to
28 replace aging infrastructure, serve new customers, and manage growth in
29 system load; and the increase in labor and non-labor operating expenses
30 caused by cost escalation. The foregoing discussion has shown that without
31 these two separate adjustments, PG&E will not be able to undertake the

⁹ Exhibit (PG&E-11), p. 2-10, Table 2-3, line 40.

1 activities and investments it believes are necessary to provide safe and
2 reliable service. Placing a public utility in this kind of situation would be very
3 poor public policy and would not be in the interests of our customers.

4 **2. The Proposed Attrition Revenue Adjustments Are Steady and Simple**

5 The requested revenue increases included in PG&E's proposed attrition
6 mechanism would provide stability for PG&E customers with respect to rates
7 and clarity to PG&E management with respect to funding its operations.
8 By pre-determining the expense escalation rates, there would be no need
9 for annual AL filing updates reflecting the latest forecasted escalation rates
10 and by funding capital additions at the TY level in real terms, PG&E could
11 manage a consistent level of capital work over the rate case cycle.
12 Additionally, the proposed mechanism does not require a detailed analysis
13 of a multi-year bottom-up capital forecast and therefore allows for an easier
14 assessment by intervenors.

15 As described in other exhibits in this proceeding, PG&E has included in
16 this application a bottom-up forecast of 2024, 2025, and 2026 capital
17 expenditures. The Commission has used bottom-up capital forecasts to
18 determine attrition revenue increases in the past.¹⁰ Nonetheless, in
19 response to intervenor concerns regarding their ability to adequately review
20 a multi-year capital forecast, PG&E proposes that the bottom-up forecast
21 only be used for gas storage, nuclear generation, hydro generation,
22 corporate real estate, and electric distribution system hardening and the
23 community rebuild program, where there are uneven forecast capital
24 additions in attrition years and/or the TY capital expenditures amount
25 exceeds the PTY bottom-up forecast capital expenditures.

26 **3. Providing an Adequate Attrition Allowance Will Help Avoid Ratcheting** 27 **Effects That Would Otherwise Occur if an Unsatisfactory Approach to** 28 **Attrition Were Adopted**

29 There are other benefits associated with adopting an attrition
30 mechanism that, consistent with Commission policies, reflects basic
31 cost-of-service fundamentals including growth in rate base during the
32 attrition period.

10 D.04-07-022.

1 First, a matching of revenues and capital costs allows a utility to
2 maintain operating and maintenance activities at a consistent level
3 throughout the rate case period, rather than having to ratchet expenses
4 down in order to make possible the necessary capital investments. PG&E
5 does not believe an arbitrary reduction of operating activities in the attrition
6 years is in the customers' interest nor is it a sound management practice.
7 However, PG&E would be required to do so if it wanted to earn the
8 authorized rate of return and did not have a proper capital component to its
9 attrition mechanism.

10 Second, adoption of a reasonable attrition adjustment, reflecting realistic
11 cost assumptions and basic cost-of-service principles results in less
12 dramatic TY increases. When utilities are forced to live within attrition
13 increases that do not adequately fund operations, activities are shifted out
14 and utilities are forced to request greater increases in the next rate case
15 cycle, resulting in the potential for significant TY rate increases. If attrition
16 year increases are adequate, utilities are able to request more modest
17 changes in the TY, resulting in a smoother rate trajectory for customers
18 and a more consistent level of work for utilities to manage across rate
19 case cycles.

20 **4. The Proposed Attrition Mechanism Provides Substantial Incentives for** 21 **Productivity Improvement**

22 The attrition mechanism proposed by PG&E provides a fair opportunity
23 to earn the authorized rate of return. It does not guarantee the Utility
24 recovery of all increases in costs. Adoption of PG&E's proposed attrition
25 mechanism does not interfere with utility incentives to manage costs and
26 identify productivity improvements. PG&E has ample incentives for
27 efficiency for both expenses and capital expenditures.

28 Under PG&E's proposal, revenue requirements for the attrition years
29 would be estimated using the Commission-adopted operating expenses and
30 capital additions for 2023 as a starting point. The attrition year revenue
31 requirement adjustments will reflect fixed increases from these adopted
32 amounts with shareholders bearing the risk for actual levels of cost
33 escalation. To add to that, because those amounts do not account for
34 higher operating costs due to a growing customer base, the expense of

1 serving new customers must be absorbed through productivity
2 improvements. It is incumbent upon management to find those efficiencies
3 so that it can operate the Utility within its fixed revenue increases and earn
4 the authorized rate of return. Any efficiencies achieved are also then
5 passed on to customers in future rate cases. All of this means PG&E will
6 maintain a strong incentive to prudently manage its costs throughout the
7 rate case cycle.

8 **5. The Proposed Attrition Mechanism Reasonably Captures the Impact of**
9 **Operating Activities Not Expected to Follow a Normal Pattern Over the**
10 **Rate Case Cycle**

11 As previously mentioned, the scale of PG&E's operating activities is
12 generally consistent YOY, such that escalation applied to TY operating
13 expense levels provides a reasonable estimate of PTY expense growth.
14 However, certain operating activities are not expected to follow that normal
15 pattern and under PG&E's proposal, PTY revenues would be adjusted such
16 that significant fluctuations do not create a misalignment of authorized
17 revenues and cost of service. In the interest of achieving a simple
18 mechanism, PG&E has proposed that such adjustments be limited to
19 situations where a substantial change in operating activities is assured and
20 the impact on PG&E's costs can be reasonably estimated. The specific
21 adjustments PG&E is proposing for gas storage, VM, declining expenses
22 associated with the planned closure of DCCP, non-residential rates
23 implementation costs with revised TOU periods, A&G Corporate items
24 associated with actuarial estimates and net employee headcount changes,
25 and EPSS are consistent with that approach and underlying objective.

26 **6. Attrition Year Increases That Capture Only Inflation Would Deny PG&E**
27 **the Opportunity to Earn the Authorized Rate of Return While**
28 **Maintaining Spending in Real Terms**

29 As indicated in Figure 1-1 of this exhibit, there is a tremendous gap
30 between CPI and reasonable expectations for revenue requirement growth
31 using the basic cost-of-service fundamentals applied by PG&E's attrition
32 model. PG&E estimates a \$927 million¹¹ increase in capital revenue

¹¹ Exhibit (PG&E-11), p. 2-10, Table 2-3, line 44.

1 requirements in 2024, and a \$206 million¹² increase in capital additions
2 from 2023 to 2024. Assuming the profile of 2023 capital additions, an
3 estimated CPI based increase to capital revenue requirement of \$206 million
4 clearly would not cover capital cost increases for 2024 and would by
5 PG&E's estimates require a \$722 million YOY reduction in operating
6 expense in nominal terms in order to keep cost-of-service growth in line with
7 attrition. In real terms, PG&E estimates the required PTY operating
8 expense reduction would be \$812 million in 2024.¹³ Additional comparable
9 expense reductions would then be required in 2025 and 2026, the second
10 and third attrition years. Even if operationally-feasible, an additional YOY
11 reduction in capital additions would have only a minor impact on revenue
12 requirements, due to the lost flow through tax benefit for repairs, so
13 realistically the shortfall could not be offset by further cutting PTY capital
14 expenditures.

15 Accordingly, adoption of an inflation approach to attrition, rather than an
16 approach that properly applies cost-of-service principles, would leave PG&E
17 with the Hobson's choice of having to either slash operating activities in the
18 attrition years or provide investors with an inadequate rate of return, neither
19 of which are sustainable options.

20 As has already been stated, the fundamental drivers of growth in a
21 utility's capital costs are different from the drivers of growth in operating
22 expenses and the Commission acknowledged that fact in PG&E's 2014
23 GRC decision. Growth in capital revenue requirements depends almost
24 entirely on the difference between plant additions and depreciation. A utility
25 that has little replacement activity (e.g., a utility owning a major interstate
26 transmission line) may actually have decreasing capital costs after a TY,
27 even in a high inflationary environment. In contrast, a utility having high
28 replacement activity and older, depreciated plant (similar to the situations of
29 PG&E and SCE) would be expected to face significantly increasing capital
30 costs, even in a low inflationary environment.

12 Exhibit (PG&E-11), p. 3-5, Table 3-2, line 6, net capital additions under PG&E's attrition proposal is a TY forecast of \$6,476 million and 2024 forecast of \$5,740 million.

13 Calculated by adding PG&E's estimated operating expense escalation of \$91 million to the \$722 million reduction in nominal terms.

1 Economically, the need for attrition increases is inflated by the fact that
 2 the regulated price a utility can charge is established by the historical cost of
 3 its plant and not on marginal replacement cost. In competitive industries,
 4 prices trend towards current replacement cost, with short-term variations
 5 depending on supply and demand. In contrast, utility prices are established
 6 by authorized operating expenses (which reflect current costs) and capital
 7 costs (which are based on historical costs rather than replacement, or
 8 marginal cost). Because historical costs are generally very low for long-lived
 9 assets, a utility that begins replacing its aging infrastructure will experience
 10 growth in capital revenue requirements that can easily outpace normal
 11 cost escalation.

12 **7. The Use of CPI to Escalate the Expense Portion of PG&E's Revenue** 13 **Requirement Is Also Misguided**

14 As described above, inflation (whether measured by the CPI or some
 15 other indicator) is not what drives capital revenue requirement growth and
 16 is therefore not an appropriate basis to use in escalating the *capital*
 17 components of PG&E's revenue requirement. CPI is also fundamentally the
 18 wrong index to use in projecting gas and electric utility *expense* increases.
 19 According to IHS Markit, the CPI measures changes in the prices of goods
 20 and services bought by households. It is based on a sample of prices for
 21 food, clothing, shelter, fuels and transportation, medical services, and other
 22 goods and services that people buy for day-to-day living. Price change is
 23 measured by pricing essentially the same market basket of goods and
 24 services at regular intervals and comparing aggregate costs with the costs
 25 of the same market basket in a selected base period.¹⁴

26 The U.S. Bureau of Labor Statistics (BLS) reports that major groups and
 27 examples in the basket of goods and service which comprise CPI are:

28 FOOD AND BEVERAGES (breakfast cereal, milk, coffee, chicken, wine,
 29 full service meals, snacks); HOUSING (rent of primary residence,
 30 owners' equivalent rent, fuel oil, bedroom furniture); APPAREL (men's
 31 shirts and sweaters, women's dresses, jewelry); TRANSPORTATION
 32 (new vehicles, airline fares, gasoline, motor vehicle insurance);
 33 MEDICAL CARE (prescription drugs and medical supplies, physicians'

14 The BLS Handbook of Methods, Consumer Price Index homepage.
 <<https://www.bls.gov/opub/hom/cpi/home.htm>> (as of June 29, 2021).

1 services, eyeglasses and eye care, hospital services); RECREATION
2 (televisions, toys, pets and pet products, sports equipment, admissions);
3 EDUCATION AND COMMUNICATION (college tuition, postage,
4 telephone services, computer software and accessories); OTHER
5 GOODS AND SERVICES (tobacco and smoking products, haircuts and
6 other personal services, funeral expenses).¹⁵

7 As the description indicates, CPI is tracking what households are
8 purchasing for day to day living. Households are not purchasing steel cable,
9 electronic switching equipment, and jackhammers for day to day living, nor
10 is PG&E buying breakfast cereal, renting an apartment, or purchasing
11 children's toys. The Commission clearly articulated the inherent
12 shortcoming of CPI in SCE's 2003 GRC D.04-07-022 as follows:

13 The CPI may be a simple, accessible measure of general inflation faced
14 by urban U.S. consumers, but that alone does not make it appropriate
15 as a measure of price changes faced by an electric utility. It does not
16 specifically cover the prices of the typical goods SCE purchases.
17 Conversely, SCE's proposed escalation rates were not designed to track
18 the general level of inflation, and there is no reason why they should
19 do so.¹⁶

20 The Commission again reaffirmed the problems with CPI in PG&E's
21 2014 GRC decision which indicated:

22 We also decline to apply the CPI as an escalation factor. The CPI
23 reflects consumer retail price changes, not the escalation in wholesale
24 purchase of utility goods and services. Accordingly, we generally adopt
25 industry-specific escalation factors, rather than use of the CPI.¹⁷

26 Most recently in D.19-09-051, the Commission found that applying
27 a percentage increase based on the CPI does not reflect how utilities incur
28 costs because it is a broad wholesale pricing index which reflects price
29 increases for goods and services in general and does not sufficiently
30 capture the operations and maintenance escalation inputs of San Diego Gas
31 & Electric Company (SDG&E) and Southern California Gas Company
32 (SoCalGas). The Commission found "that Global Insight escalation rates

¹⁵ BLS report (Consumer Price Index), p.3,
<<https://www.bls.gov/opub/hom/cpi/pdf/cpi.pdf>> (as of June 29, 2021).

¹⁶ D.04-07-022, p. 278.

¹⁷ D.14-08-032, p. 653.

1 are specific to the utility industry and more accurately reflects SDG&E and
2 SoCalGas' inflationary cost increases."¹⁸

3 As the name suggests, CPI is a price index and not a total cost index.
4 The price a firm sets for its products is a function of both the firm's projected
5 total costs and sales volume. The percentage change in the price that must
6 be charged to cover the change in costs from period to period is roughly
7 equal to the percentage change in total costs less the percentage change in
8 the quantity sold. If, for example, total costs are projected to increase
9 5 percent in the next period and sales quantity is expected to increase
10 2 percent, then the firm only needs to increase its price by 3 percent to
11 generate the increase in revenues needed to cover the increase in costs.
12 It is this 3 percent price increase that is being picked up in the CPI, not the
13 5 percent cost increase.

14 If PG&E were able to grow revenues by increasing sales, an inflationary
15 price-based index might become more feasible, at least for expenses,
16 because the needed revenue requirement would be covered by the
17 inflationary increase as well as by the percentage increase in sales.
18 However, by adopting sales balancing accounts, California does not permit
19 PG&E to increase revenues by increasing sales during the PTY period.
20 As a result, the only way for the Company to change its revenue between
21 GRCs is through an adjustment to base revenue requirements (i.e., PTY
22 attrition increases) and that adjustment should be designed to reflect
23 reasonable expectations for changes in utility costs, not CPI.

24 To conclude, suggestions that PG&E's cost-of-service increases should
25 be in line with general CPI changes, even on the expense portion of the
26 revenue requirement, are misguided.

27 **8. The Use of TY Adopted Amounts to Estimate PTY Capital Additions Is**
28 **More Aligned With the Principles of Forecast TY Ratemaking Than a**
29 **Historical Average**

30 Historical data is used as context in TY rate cases, but the basic
31 philosophy behind TY ratemaking is that authorized revenue requirements
32 should be established based on reasonable expectations of a utility's future

¹⁸ D.19-09-051, p. 708.

1 cost of service. In the most recent rate case plan decision,¹⁹ the CPUC
2 further refined its TY ratemaking standard by incorporating a risk-informed
3 decision-making framework into the GRC. PG&E's PTY capital forecast
4 developed through the enterprise-wide planning and budgeting process
5 (known as the Operating Rhythm), described in Exhibit (PG&E 2),
6 Chapter 3, follows that framework; therefore, PG&E believes it is the
7 strongest foundation for estimating PTY capital additions, including the
8 impact of any forecast adjustments deemed appropriate based on the
9 evidence presented in this proceeding. As previously discussed however,
10 intervenors have stated in past GRCs that they do not have the resources to
11 examine a multi-year capital forecast and the Commission has been
12 skeptical as to their reliability. As such, to simplify the projection of PTY
13 capital additions, PG&E believes the next best way to estimate those capital
14 additions is by looking at the TY.

15 The TY capital addition amounts adopted in this proceeding will
16 represent the outcome of a rigorous forecast examination including an
17 analysis of PG&E's risk-informed decision-making framework. Given that
18 process, PG&E believes the adopted TY amounts will represent the level of
19 capital funding most consistent with the objective stated in the CPUC's rate
20 case plan decision:

21 In sum, our end goal is to revise the RCP to better facilitate utility
22 revenue requirements showings based on a risk-informed
23 decision-making process that will lead to safe and reliable service levels
24 that are in compliance with state and federal guidelines, rational,
25 well-informed and comparable to best industry practices. Likewise,
26 laying the proper procedural foundation through improvements to the
27 RCP will better equip Commission decision makers with the necessary
28 information to ensure that we prioritize safety while continuing our
29 long-standing mandate to ensure that adopted rates are just and
30 reasonable.²⁰

31 While it is true that capital expenditures are a collection of individual
32 projects, and therefore the PTY period is not expected to look exactly like
33 the TY, the majority of PG&E's capital projects are components of ongoing
34 programs that have similar levels of activities and costs YOY. As such, to

¹⁹ D.20-01-002.

²⁰ R.13-11-006, pp. 7-8.

1 estimate capital investment needs in the PTY period, PG&E believes the
2 level of additions determined by the Commission to be appropriate for the
3 TY provides a more rational and well-informed basis than a historical
4 average. See Exhibit (PG&E-11), Chapter 3 for additional discussion.

5 **F. Implementation of PTYR**

6 One of the goals of a PTYR mechanism adjustment is to provide a
7 streamlined process for setting revenue requirements between GRCs. Under
8 PG&E's proposed attrition mechanism, attrition ALs would only be necessary if a
9 Z-factor event were to occur or there was a change in the adopted COC.
10 Consistent with its current practice, PG&E proposes that annual gas and electric
11 revenue requirement changes adopted in this proceeding be included in PG&E's
12 Annual Electric True-Up and Annual Gas True-Up filings.

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
ATTRITION AND PROPOSED ATTRITION CHANGES
[INCLUDES FEBRUARY 28, 2022 ERRATA AND
FEBRUARY 28, 2022 SUPPLEMENTAL TESTIMONY]

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
ATTRITION AND PROPOSED ATTRITION CHANGES

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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **CHAPTER 2**
3 **ATTRITION AND PROPOSED ATTRITION CHANGES**
4

5 **A. Introduction**

6 **1. Scope and Purpose**

7 This chapter sets forth illustrative revenue requirement changes for
8 electric and gas distribution, electric generation, and Gas Transmission and
9 Storage (GT&S) under Pacific Gas and Electric Company's (PG&E or the
10 Utility) proposed Post Test-Year Ratemaking (PTYR) mechanism for 2024,
11 2025, and 2026. In this application, PG&E requests that the California
12 Public Utilities Commission (CPUC or Commission) authorize a PTYR
13 mechanism to calculate annual changes in the adopted revenue
14 requirements from 2023 until the revenue requirements determined in
15 PG&E's next GRC become effective. This chapter describes the specific
16 calculations PG&E proposes to use under this mechanism and presents the
17 illustrative revenue requirement increase amounts based on PG&E's
18 proposed 2023 test year (TY) revenue requirements and capital additions
19 forecasts.

20 **2. Summary of Request**

21 PG&E requests that the Commission authorize implementation of the
22 PTYR mechanism outlined below. The computational form of the
23 mechanism PG&E proposes for adjusting labor and wage-related benefits,
24 materials and supplies, and employee medical costs, is similar to that
25 proposed in PG&E's 2020 General Rate Case (GRC). Related to capital
26 costs, PG&E proposes that the adopted TY net capital additions amounts,
27 adjusted to reflect cost escalation, be used to determine rate base growth in
28 the attrition years along with forecasted changes in accumulated
29 depreciation and deferred taxes. In the instances of nuclear generation,
30 hydro generation, corporate real estate, gas storage, electric distribution
31 system hardening, and the community rebuild program where the TY capital
32 expenditures amount exceeds the Post Test-Year (PTY) bottom-up forecast
33 capital expenditures, and/or there are uneven forecasts, PG&E proposes to

1 use the bottom-up forecast capital additions. Related to operating
 2 expenses, PG&E proposes escalating the majority of expenses in the
 3 attrition years to reflect cost escalation. For certain expenses that are not
 4 expected to follow a normal pattern of escalation, PG&E proposes special
 5 expense adjustments. PG&E proposes to continue the Z-factor mechanism
 6 with a modification to update TY and PTY revenue requirement adjustments
 7 through an advice letter (AL) process.

8 Table 2-1 summarizes the 2023 GRC revenue requirement request and
 9 the incremental revenue requirement change for 2024, 2025, and 2026 by
 10 functional area, and increases over total company gas and electric base
 11 current revenues.

TABLE 2-1
SUMMARY OF THE 2023 GRC PTYR REQUEST
(MILLIONS OF DOLLARS)

Line No.	Description	2023	2024	% Increase (decrease) over 2023	2025	% Increase (decrease) over 2024	2026	% Increase (decrease) over 2025
1	Electric Distribution	\$8,229	\$8,741	6%	\$9,490	9%	\$10,266	8%
2	Gas Distribution	2,864	3,092	8%	3,370	9%	3,659	9%
3	Electric Generation	2,405	2,396	0%	1,980	(17%)	1,309	(34%)
4	GT&S	1,842	2,128	16%	2,273	7%	2,440	7%
5	Total General Rate Case	\$15,339	\$16,357	7%	\$17,113	5%	\$17,674	3%

12 **3. Support for Request**

13 A PTYR mechanism is necessary to fund the work needed to provide
 14 safe and reliable service to customers, while offering PG&E a fair
 15 opportunity to earn the rate of return found reasonable by the Commission.
 16 PG&E believes its proposal is reasonable for all parties based on the
 17 rationale provided in Chapter 1 of this exhibit. The separate consideration of
 18 the expense and capital components of attrition follows basic cost-of-service
 19 fundamentals and is consistent with the attrition mechanism adopted in
 20 PG&E's 2014 GRC.¹

¹ D.14-08-032.

4. Organization of This Chapter

The remainder of this chapter is organized as follows:

- Section B – PG&E’s PTYR Proposal;
- Section C – Estimated 2024, 2025 and 2026 Revenue Adjustments Under PG&E’s PTYR Proposal;
- Section D – Relationship Between the PTYR and Existing and Proposed Balancing Accounts; and
- Section E – Conclusion.

B. PG&E’s PTYR Proposal

PG&E’s PTYR proposal is intended to estimate changes in the cost of providing service subsequent to 2023, due to: (1) rate base growth; (2) expense escalations; (3) discrete capital and operating expense adjustments; and (4) exogenous cost-of-service changes (Z-factor events). Attrition components included in this PTYR mechanism are described below:

- 1) Labor and labor-related escalations. Labor costs include the operations and maintenance (O&M) and Administrative and General (A&G) wages as well as payroll taxes and the wage-related portion of benefits (Federal Energy Regulatory Commission (FERC) Account 926), excluding pension.
- 2) Materials and services (non-labor) escalations for O&M and A&G expenses as well as property insurance (FERC Account 924).
- 3) Medical plan cost escalations for medical benefits costs (FERC Account 926). These costs are escalated separately based on Mercer Actuarial forecast because they are not expected to follow either the labor or non-labor escalation trends.
- 4) Capital and rate base-related adjustments as described in Chapter 3 of this exhibit.
- 5) Discrete operating expenses adjustment that are not expected to follow a normal pattern over the rate case cycle as described in Table 2-2 below.
- 6) Allocation changes related to common costs during attrition years:
 - a) Reallocation of all shared common costs, including A&G, common plant, working cash and taxes, that were previously allocated to Diablo Canyon Power Plant (DCPP) in 2023 and 2024 to other functional areas starting in 2025 due to the closure of DCPP Unit 1 in November 2024 and Unit 2 in 2025. Exhibit (PG&E-10), Chapter 8 provides the labor

- 1 allocation factors for common costs for years 2023-2026.
2 Exhibit (PG&E-10), Chapter 14 discusses the working cash reallocation
3 in 2025 and 2026.
- 4 b) Allocation factors are proposed to be modified for 2024 through 2026 for
5 wildfire liability insurance, general liability insurance including
6 non-wildfire liability insurance, third party claims and litigation
7 settlements & judgements as discussed in Exhibit (PG&E-10),
8 Chapter 8. Additionally, as explained in Exhibit (PG&E-9), Chapter 3,
9 nuclear property insurance and nuclear liability insurance for the
10 forecast year 2026 is removed from this GRC and will be recovered
11 through the next Nuclear Decommissioning Cost Triennial Proceeding.
- 12 7) As necessary, adjustments will be made to attrition-year return and income
13 taxes to reflect currently adopted debt costs, equity costs and capital
14 structure. Decision (D.) 89-01-040, the Rate Case Plan, moved
15 determination of these financial parameters to a generic Cost of Capital
16 (COC) proceeding. The calculations included in this application use the
17 financial parameters adopted in PG&E's most recent COC D.12-12-034 as
18 modified by D.13-03-015, D.17-07-005, D.19-12-056 COC proceeding and
19 updated by AL 4275-G/5887-E.²
- 20 8) As necessary, adjustments will be made for revenue requirement changes
21 associated with approved Z-factor events—defined as significant events that
22 are beyond the Utility's ability to control and cause large changes in its cost
23 structure. Each Z-factor event will only include costs in excess of a one-time
24 \$10 million deductible per event. PG&E also proposes to continue the
25 Z-factor mechanism authorized in the 2020 GRC D.20-12-005 to record
26 Z-factor events in TY and PTYs. PG&E proposes to modify the Z-factor
27 mechanism procedure to request for recovery of the revenue requirement

² D.13-03-015 established an annual COC adjustment mechanism which did not trigger in 2014 or 2015 so the current authorized COC adopted in D.12-12-034 is unchanged from 2013. A COC filing deferment of one year was approved by the CPUC on December 24, 2014, so the next full COC application was to be filed on April 20, 2016, for the 2017 TY. By letter dated November 25, 2015, the filing date was extended to April 20, 2017, for the 2018 TY. On July 13, 2017, the CPUC adopted in D.17-07-005 modifications to extend the date for the next COC filing from April 22, 2017, to April 22, 2019.

1 associated with the Z-factor events in an advice letter filing instead of an
2 application, consistent with Southern California Edison's process.

3 **C. Estimated 2024, 2025, and 2026 Revenue Adjustments Under PG&E's** 4 **PTYR Proposal**

5 Table 2-3 summarizes the total proposed 2024, 2025, and 2026 revenue
6 requirement increases by functional area based on PG&E's forecasted 2023
7 revenue requirements and capital additions forecasts. Tables 2-4, 2-8, 2-12,
8 and 2-16 include illustrative PTY Results of Operations (RO) schedules for
9 electric distribution, gas distribution, electric generation and GT&S, respectively.
10 The remaining tables (Tables 2-5, 2-6, 2-7, 2-9, 2-10, 2-11, 2-13, 2-14, 2-15,
11 2-17, 2-18, and 2-19) show the derivation of attrition year expense estimates for
12 each functional area by expense type and year. Individual components of the
13 proposed adjustments are described below.

14 **1. Labor and Labor-Related Wage Escalations**

15 Labor adjustments use escalation rates described in Exhibit (PG&E-8),
16 Chapter 4, to increase 2023 adopted operating unit (3.52 percent) and A&G
17 organization (3.28 percent) labor expenses in 2024, 2025, and 2026.³
18 Labor-related expenses subject to these adjustments also include payroll
19 taxes and wage-related benefits (FERC Account 926), excluding pension
20 and medical plan costs. PG&E's proposed labor escalation rates are
21 blended rates that reflect the wage escalation for represented and
22 non-represented employees. Contracts with the International Brotherhood
23 of Electrical Workers (IBEW) Physical and Clerical Bargaining Units and the
24 Engineers and Scientists of California (ESC) Bargaining Unit set wage levels
25 for represented employees through the end of 2025 and a contract with the
26 Service Employees International Union (SEIU) Bargaining Unit sets wage
27 levels through the end of 2021.⁴ Those agreements provide a 3.75 percent
28 for IBEW and ESC represented employees, and 3.00 percent for SEIU

3 Exhibit (PG&E-8), WP 4-22.

4 The labor escalation rates shown are based on the labor agreements, with IBEW and ESC, PG&E has in place through December 31, 2025 and labor agreement, with SEIU, PG&E has in place through December 31, 2021.

1 represented employees annual general wage increase and are assumed to
2 set wage levels through the entire 2023 GRC period.

3 For non-represented employees, the 3.07 percent escalation rate was
4 estimated based on external survey data as described in Exhibit (PG&E-8),
5 Chapter 4.

6 **2. Materials and Services (Non-Labor) Escalations**

7 Materials and Services (M&S) adjustments use escalation rates
8 described in Exhibit (PG&E-12), Chapter 3, to increase adopted 2023 O&M
9 and A&G non-labor expenses for 2024, 2025, and 2026. Non-labor
10 expenses subject to these adjustments also include property insurance
11 (FERC Account 924). Growth in attrition year M&S is based on IHS Markit
12 escalation rates, which reflect economic conditions including movement in
13 global commodity prices. PG&E will not seek to adjust or true-up these
14 rates after a final Commission decision in this proceeding.

15 **3. Medical Plan Cost Escalations**

16 Medical plan cost adjustments use escalation rates and headcount
17 forecasts described in Exhibit (PG&E-8), Chapter 5, to increase 2023
18 adopted medical plan costs for 2024, 2025, and 2026. The resulting
19 medical plan costs are part of FERC Account 926. The estimated escalation
20 rates of 4.61 percent for 2024 - 2026 are based on an actuarial estimate
21 prepared by Mercer, adjusted for headcount changes and estimated cost
22 savings from continuing investment in wellness programs and on-site
23 healthcare services.

24 **4. Capital and Rate Base Adjustments**

25 Chapter 3 of this exhibit describes the development of the PTY net plant
26 additions forecast and other PTY rate base changes. The plant additions
27 forecast is based on a simplified approach of escalating 2023 TY capital
28 additions using IHS Markit escalation rates, except for nuclear generation,
29 hydro generation, corporate real estate, gas storage, electric distribution
30 system hardening, and the community rebuild program, where PG&E
31 proposes to use a bottom-up forecast due to uneven forecast capital
32 additions for those lines of business.

5. Discrete Operating Expense Adjustments

As described in Chapter 1 of this exhibit, certain operating expenses are not expected to follow a normal pattern of escalation. Where such fluctuations can be reasonably estimated and are expected to exceed \$10 million, PG&E is proposing discrete attrition revenue adjustments to avoid a misalignment of authorized revenues and cost of service. There are seven areas where PG&E identified that meet these criteria and are proposing the use of bottom-up forecasts during attrition years.

First, as described in Exhibit (PG&E-3), Chapter 7, gas storage expense forecasts include the inspection and assessment work required under the Pipeline and Hazardous Materials Safety Administration and California Department of Conservation, Geologic Energy Management Division (CalGEM) regulations. Reinspection of wells are forecast to occur on a 7-year cycle, and are expected to start in 2026, to maintain compliance with the CalGEM regulations reflected in Section 1726. The reinspection requirements drive the increase of gas storage expense cost forecasts in 2026.

Second, as described in Exhibit (PG&E-4), Chapter 9, vegetation management is a multi-year effort to remove overhanging vegetation to enhance public safety by further reducing the risk of power outages and prevent the possibility of wildfire ignitions. In accordance with the CPUC direction, PG&E submitted supplemental testimony on February 25, 2022 to reflect the utility's proposal to underground 10,000 miles of electric distribution powerlines in high fire risk areas to align to PG&E's updated integrated wildfire mitigation strategy. The Supplemental Testimony reduces the Utility's previous request for vegetation management program expenses by approximately \$1 billion over the period from 2023 to 2026. Specifically, PG&E is forecasting attrition expense reductions of \$26 million, \$50 million and \$83 million for years 2024, 2025 and 2026, respectively. These reductions have been incorporated into the forecast electric distribution attrition adjustments.⁵

⁵ See Exhibit (PG&E-4), WP 9-13, Table 9-13.

1 Third, as described in Exhibit (PG&E-5), Chapter 3, the planned closure
2 of DCPD will incur less operating expenses during attrition years. Thus,
3 expense forecasts in attrition years are proposed to follow the bottom-up
4 forecasts, which will reflect an expense reduction of nearly 50 percent in
5 2025 and no DCPD operating expenses in 2026.

6 Fourth, as described in Exhibit (PG&E-6), Chapter 3, PG&E expects to
7 update Time-of-Use (TOU) periods on a mandatory basis, and Peak-Day
8 Pricing (PDP) event hours, for non-residential customers in 2026, and is
9 requesting an attrition adjustment in 2026 to cover this transition cost.

10 Fifth, due to DCPD closure and forecast headcount changes during
11 attrition years, PG&E is proposing to use bottom-up forecast for employee
12 healthcare and other A&G items, which incorporates the headcount forecast
13 and Mercer's actuarial forecasted escalation factors, as described in Exhibit
14 (PG&E-7), Chapter 1A, Exhibit (PG&E-8), Chapters 4 and 5, and Exhibit
15 (PG&E-9), Chapter 3.

16 Sixth, Exhibit (PG&E-9), Chapter 3, proposes an increase to insurance
17 premium costs by \$75 million in 2024, to establish a self-insured fund to
18 meet the first \$1 billion in coverage that is required to access the Wildfire
19 Fund created by Assembly Bill 1054, in addition to or as an alternative to
20 solely acquiring traditional insurance policies.

21 Lastly, as described in Exhibit (PG&E-4), Chapter 4.6, Enhanced
22 Powerline Safety Settings (EPSS) is a new wildfire mitigation program that is
23 introduced in the February 25, 2022 supplemental testimony update. EPSS
24 is an initiative to reduce wildfire risk by minimizing the probability of an
25 ignition event when a fault occurs on a distribution line in certain high fire-
26 risk areas. PG&E is forecasting attrition expense reductions for the EPSS
27 program of \$5 million, \$5 million, and \$7 million for years 2024, 2025 and
28 2026, respectively. The program cost does not follow a normal pattern of
29 escalation and has been incorporated into the electric distribution attrition
30 adjustment.

31
32 Table 2-2 and WP Table 2-47 provides the list and associated details of
33 the use of bottom-up forecasts for operating expenses.

TABLE 2-2
DISCRETE EXPENSE ATTRITION AMOUNTS – USE OF BOTTOM-UP FORECAST
(MILLIONS OF NOMINAL DOLLARS)

Line No.	Description	2023	2024	2025	2026	Testimony Reference
1	Gas storage	\$18	\$22	\$24	\$46	Exhibit (PG&E-3), Chapter 7
2	Vegetation management	1,059	1,033	983	900	Exhibit (PG&E-4), Chapter 9
3	DCCP closure	314	315	167	–	Exhibit (PG&E-5), Chapter 3
4	TOU mandatory transition to revised TOU periods and Peak Day Pricing Event Hour Revision attrition adjustment	–	–	–	12	Exhibit (PG&E-6), Chapter 3
5	Enhanced Powerline Safety Settings (EPSS) ^(a)	151	146	141	134	Exhibit (PG&E-4), Chapter 4.6
6	Total O&M expense (lines 1 – 5)	\$1,541	\$1,516	\$1,315	\$1,091	
7	Healthcare & other A&G items	\$960	\$1,000	\$1,025	\$1,047	Exhibit (PG&E-7), Chapter 1A; Exhibit (PG&E-8), Chapter 4 and 5; Exhibit (PG&E-9), Chapter 3
8	Wildfire excess liability insurance	708	783	783	783	Exhibit (PG&E-9), Chapter 3
9	Total companywide expense (line 7 and 8) ^(b)	\$1,668	\$1,783	\$1,807	\$1,830	
10	Total discrete expense attrition amounts (line 6 and 9)	\$3,210	\$3,299	\$3,122	\$2,921	

(a) EPSS is a new category added as a result of PG&E's February 25, 2022 supplemental testimony.

(b) Corporation amounts have been included at 99 percent (See Exhibit (PG&E-9), Ch. 9).

1 D. Relationship Between the PTYR and Existing and Proposed 2 Balancing Accounts

3 PG&E recognizes that its proposed attrition mechanism includes revenue
4 requirement increases that relate to costs subject to balancing account
5 protection. As discussed in Exhibit (PG&E-12), Chapter 7, whenever PG&E's
6 attrition request includes revenue requirement increases for costs subject to
7 balancing account treatment, PG&E will adjust the authorized revenue
8 requirements, which are used in the balancing account as a measure against
9 costs, to reflect attrition increases.

10 E. Conclusion

11 PG&E's proposed attrition mechanism was designed to estimate PTY
12 revenue requirement growth using the simple and transparent application of
13 basic cost-of-service fundamentals to adopted TY costs. If adopted, it would
14 provide rate stability to PG&E's customers, fund the work needed to provide safe
15 and reliable service, and maintain incentives for PG&E to manage its operations
16 efficiently and effectively.

**TABLE 2-3
RO AT PROPOSED RATES
SUMMARY OF ATTRITION INCREASES
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Description	Attrition Year		
		2024 (A)	2025 (B)	2026 (C)
ELECTRIC DISTRIBUTION				
1	Operating Expenses	54,067	90,455	98,582
2	Vegetation Management program	(26,359)	(49,239)	(83,296)
3	Enhanced Powerline Safety Settings (EPSS)	(4,826)	(5,477)	(7,115)
4	TOU Period Change	-	-	11,423
5	Corp items	(17,795)	22,662	26,405
6	Subtotal Expense:	5,087	58,401	45,999
Capital:				
7	Taxes ^(a)	77,353	158,955	166,482
8	Depreciation ^(c)	198,576	249,844	264,056
9	Return	231,404	281,271	300,076
10	Subtotal Capital:	507,333	690,069	730,613
11	Total	512,420	748,470	776,612
GAS DISTRIBUTION				
12	Operating Expenses	31,165	50,851	55,434
13	TOU Period Change			248
14	Corp items	4,745	11,973	13,951
15	Subtotal Expense:	35,910	62,824	69,633
Capital:				
16	Taxes ^(a)	34,118	39,139	38,774
17	Depreciation ^(c)	102,923	125,129	133,599
18	Return	54,224	50,929	47,227
19	Subtotal Capital:	191,265	215,197	219,600
20	Total	227,175	278,021	289,233
ELECTRIC GENERATION				
21	Operating Expenses	11,262	(59,647)	(100,653)
22	Diablo Canyon Power Plant closure ^(b)	1,295	(148,292)	(166,649)
23	Corp items	4,957	(31,982)	(41,280)
24	Subtotal Expense:	17,513	(239,921)	(308,583)
Capital:				
25	Taxes ^(a)	(23,304)	(39,455)	30,904
26	Depreciation ^(c)	14,151	(76,210)	(334,903)
27	Return	(16,454)	(60,392)	(58,910)
28	Subtotal Capital:	(25,607)	(176,058)	(362,909)
29	Total	(8,094)	(415,979)	(671,492)
GAS TRANSMISSION AND STORAGE				
30	Operating Expenses	25,308	32,592	34,864
31	Gas Storage	4,505	1,973	21,702
32	Corp items	2,262	5,707	6,649
33	Subtotal Expense:	32,075	40,271	63,216
Capital:				
34	Taxes ^(a)	56,993	16,174	22,221
35	Depreciation ^(c)	131,961	37,345	36,228
36	Return	65,465	50,974	45,048
37	Subtotal Capital:	254,418	104,493	103,497
38	Total	286,493	144,764	166,712
ELECTRIC AND GAS DEPARTMENTS				
39	Subtotal Expense: (Lines 6, 15, 24, 33)	90,584	(78,425)	(129,735)
40	Subtotal Expense: excluding DCPD O&M	89,290	69,868	36,914
Capital:				
41	Taxes ^(a)	145,160	174,812	258,381
42	Depreciation ^(c)	447,611	336,108	98,979
43	Return	334,639	322,781	333,441
44	Subtotal Capital:	927,410	833,701	690,802
45	Total	1,017,994	755,276	561,067

(a) Includes Property and Income Taxes.

(b) Includes Operations and Maintenance, IT and other associated expenses.

(c) Includes depreciation, decommissioning and amortization expense.

TABLE 2-4
RO AT PROPOSED RATES
ELECTRIC DISTRIBUTION
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	Test Year	Attrition Year 2024		Attrition Year 2025		Attrition Year 2026	
		2023	Increase	Total	Increase	Total	Increase	Total
		(A)	(B)	(C)	(D)	(E)	(F)	(G)
REVENUE:								
1	Revenue Collected in Rates	8,228,751	512,420	8,741,171	748,470	9,489,641	776,612	10,266,253
2	Plus Other Operating Revenue	218,191	-	218,191	-	218,191	-	218,191
3	Total Operating Revenue	8,446,942	512,420	8,959,362	748,470	9,707,832	776,612	10,484,445
OPERATING EXPENSES:								
4	Energy Costs	-	-	-	-	-	-	-
5	Production	-	-	-	-	-	-	-
6	Storage	-	-	-	-	-	-	-
7	Transmission	2,429	47	2,476	46	2,523	48	2,570
8	Distribution ¹	2,303,758	(427)	2,303,331	(24,080)	2,279,251	(59,273)	2,219,978
9	Customer Accounts	223,203	6,364	229,567	6,410	235,977	17,989	253,966
10	Uncollectibles	25,340	1,537	26,877	2,245	29,122	2,330	31,452
11	Customer Services	-	-	-	-	-	-	-
12	Administrative and General	1,255,816	(8,430)	1,247,386	65,913	1,313,299	76,755	1,390,055
13	Franchise & SFGR Tax Requirement	64,459	3,910	68,369	5,712	74,081	5,926	80,007
14	Amortization	-	-	-	-	-	-	-
15	Wage Change Impacts	-	-	-	-	-	-	-
16	Other Price Change Impacts	-	-	-	-	-	-	-
17	Other Adjustments	(2,407)	-	(2,407)	-	(2,407)	-	(2,407)
18	Subtotal Expenses:	3,872,598	3,002	3,875,599	56,247	3,931,847	43,775	3,975,621
TAXES:								
19	Superfund	-	-	-	-	-	-	-
20	Property	322,036	57,747	379,783	64,480	444,262	70,221	514,483
21	Payroll	63,576	2,085	65,661	2,154	67,815	2,224	70,039
22	Business	733	-	733	-	733	-	733
23	Other	13,794	-	13,794	-	13,794	-	13,794
24	State Corporation Franchise	93,505	17,932	111,437	30,021	141,458	31,583	173,041
25	Federal Income	130,997	1,674	132,671	64,454	197,124	64,679	261,803
26	Total Taxes	624,640	79,438	704,079	161,108	865,187	168,707	1,033,893
27	Depreciation ¹	2,089,409	198,576	2,287,985	249,844	2,537,829	264,056	2,801,885
28	Decommissioning	-	-	-	-	-	-	-
29	Nuclear Decommissioning	-	-	-	-	-	-	-
30	Total Operating Expenses	6,586,648	281,016	6,867,663	467,199	7,334,862	476,537	7,811,399
31	Net for Return	1,860,295	231,404	2,091,699	281,271	2,372,970	300,076	2,673,045
32	Rate Base	25,689,645	3,250,221	28,939,866	3,824,754	32,764,620	4,079,857	36,844,478
RATE OF RETURN:								
33	On Rate Base		7.24%	7.23%		7.24%		7.25%
34	On Equity ^{Note 1}							

¹ Wildfire Mitigation amounts subject to reasonableness review have been excluded from this RO schedule, per the October 1, 2021, Scoping Memo and Ruling.

Note 1. Electric Distribution-related AB 1054 ROE is 0% and non-AB 1054 ROE is at 10.25%. The following workpapers show ROE, on line 34:

- Electric Distribution non-AB 1054 see Exhibit (PG&E-11), Table 2-23

- Electric Distribution AB 1054 see Exhibit (PG&E-11), Table 2-27

**TABLE 2-5
ELECTRIC DISTRIBUTION
ATTRITION YEAR 2024 EXPENSES
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Description	2023	2024			Expense Estimate
		Escalation Basis (A)	Escalation Factor (B)	Base Estimate (C)	Adjustments (D)	
Production						
1	Labor	0	1.0352	0	0	0
2	Materials & Supplies	0	1.0000	0	0	0
3	Other	0	1.0000	0	0	0
4	Total Production	0		0	0	0
Storage						
5	Labor	0	1.0352	0	0	0
6	Materials & Supplies	0	1.0191	0	0	0
7	Other	0	1.0000	0	0	0
8	Total Storage	0		0	0	0
Transmission						
9	Labor	506	1.0352	523	0	523
10	Materials & Supplies	1,924	1.0152	1,953	0	1,953
11	Other	0	1.0000	0	0	0
12	Total Transmission	2,429		2,476	0	2,476
Distribution						
13	Labor	642,551	1.0352	665,169	(7,784)	657,385
14	Materials & Supplies	1,661,207	1.0216	1,697,068	(51,122)	1,645,946
15	Other	0	1.0000	0	0	0
16	Total Distribution	2,303,758		2,362,237	(58,906)	2,303,331
Customer Accounts						
17	Labor	129,525	1.0328	133,773	0	133,773
18	Materials & Supplies	93,678	1.0226	95,794	0	95,794
19	Other	0	1.0000	0	0	0
20	Total Customer Accounts (Excluding Uncollectibles)	223,203		229,567	0	229,567
Customer Service						
21	Labor	0	1.0328	0	0	0
22	Materials & Supplies	0	1.0226	0	0	0
23	Other	0	1.0000	0	0	0
24	Total Customer Service	0		0	0	0
Administrative & General						
25	Labor	193,521	1.0328	199,868	30	199,898
26	Materials & Supplies	811,880	1.0226	830,217	(40,045)	790,172
27	Other	111,794	1.0000	111,794	310	112,104
28	Medical	107,755	1.0461	112,724	584	113,308
29	Wage-Related	30,866	1.0328	31,878	27	31,905
30	Total Admin & General (Excluding Franchises)	1,255,816		1,286,481	(39,095)	1,247,386
Other						
31	Labor	0	1.0352	0	0	0
32	Materials & Supplies	0	1.0000	0	0	0
33	Other	(2,407)	1.0000	(2,407)	0	(2,407)
34	Total Other Adjustments	(2,407)		(2,407)	0	(2,407)
35	Total Labor Excl Wage-Related A&G	966,102		999,333	(7,754)	991,580
36	Wage-Related Administrative & General	30,866		31,878	27	31,905
37	Total Labor	996,968		1,031,212	(7,727)	1,023,484
38	Total Materials & Supplies	2,568,690		2,625,032	(91,168)	2,533,864
39	Total Other	109,387		109,387	310	109,696
40	Total Medical	107,755		112,724	584	113,308
41	Total Operating & Maintenance Expenses (Excl F&U)	3,782,799		3,878,354	(98,001)	3,780,353
42	Increase			95,555	(98,001)	(2,446)
43	Uncollectibles			290	(297)	(7)
44	Franchises			736	(754)	(19)
45	Total Increase Including Uncollectibles & Franchises			96,580	(99,052)	(2,472)

TABLE 2-6
ELECTRIC DISTRIBUTION
ATTRITION YEAR 2025 EXPENSES
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2024	2025			Expense Estimate (E)
		Escalation Basis (A)	Escalation Factor (B)	Base Estimate (C)	Adjustments (D)	
Production						
1	Labor	0	1.0352	0	0	0
2	Materials & Supplies	0	1.0000	0	0	0
3	Other	0	1.0000	0	0	0
4	Total Production	0		0	0	0
Storage						
5	Labor	0	1.0352	0	0	0
6	Materials & Supplies	0	1.0186	0	0	0
7	Other	0	1.0000	0	0	0
8	Total Storage	0		0	0	0
Transmission						
9	Labor	523	1.0352	542	0	542
10	Materials & Supplies	1,953	1.0143	1,981	0	1,981
11	Other	0	1.0000	0	0	0
12	Total Transmission	2,476		2,523	0	2,523
Distribution						
13	Labor	657,385	1.0352	680,525	(8,485)	672,040
14	Materials & Supplies	1,645,946	1.0198	1,678,538	(71,327)	1,607,211
15	Other	0	1.0000	0	0	0
16	Total Distribution	2,303,331		2,359,064	(79,812)	2,279,251
Customer Accounts						
17	Labor	133,773	1.0328	138,161	0	138,161
18	Materials & Supplies	95,794	1.0211	97,816	0	97,816
19	Other	0	1.0000	0	0	0
20	Total Customer Accounts (Excluding Uncollectibles)	229,567		235,977	0	235,977
Customer Service						
21	Labor	0	1.0328	0	0	0
22	Materials & Supplies	0	1.0211	0	0	0
23	Other	0	1.0000	0	0	0
24	Total Customer Service	0		0	0	0
Administrative & General						
25	Labor	199,898	1.0328	206,454	14,651	221,105
26	Materials & Supplies	790,172	1.0211	806,854	5,340	812,194
27	Other	112,104	1.0000	112,104	7,443	119,547
28	Medical	113,308	1.0461	118,533	7,109	125,642
29	Wage-Related	31,905	1.0328	32,951	1,860	34,811
30	Total Admin & General (Excluding Franchises)	1,247,386		1,276,896	36,403	1,313,299
Other						
31	Labor	0	1.0352	0	0	0
32	Materials & Supplies	0	1.0000	0	0	0
33	Other	(2,407)	1.0000	(2,407)	0	(2,407)
34	Total Other Adjustments	(2,407)		(2,407)	0	(2,407)
35	Total Labor Excl Wage-Related A&G	991,580		1,025,682	6,166	1,031,848
36	Wage-Related Administrative & General	31,905		32,951	1,860	34,811
37	Total Labor	1,023,484		1,058,634	8,026	1,066,659
38	Total Materials & Supplies	2,533,864		2,585,189	(65,987)	2,519,203
39	Total Other	109,696		109,696	7,443	117,139
40	Total Medical	113,308		118,533	7,109	125,642
41	Total Operating & Maintenance Expenses (Excl F&U)	3,780,353		3,872,052	(43,409)	3,828,643
42	Increase			91,699	(43,409)	48,290
43	Uncollectibles			278	(132)	146
44	Franchises			707	(335)	372
45	Total Increase Including Uncollectibles & Franchises			92,684	(43,875)	48,809

TABLE 2-7
ELECTRIC DISTRIBUTION
ATTRITION YEAR 2026 EXPENSES
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2025	2026			Expense Estimate
		Escalation Basis (A)	Escalation Factor (B)	Base Estimate (C)	Adjustments (D)	
Production						
1	Labor	0		0	0	0
2	Materials & Supplies	0	1.0000	0	0	0
3	Other	0	1.0000	0	0	0
4	Total Production	0		0	0	0
Storage						
5	Labor	0	1.0352	0	0	0
6	Materials & Supplies	0	1.0179	0	0	0
7	Other	0	1.0000	0	0	0
8	Total Storage	0		0	0	0
Transmission						
9	Labor	542	1.0352	561	0	561
10	Materials & Supplies	1,981	1.0144	2,009	0	2,009
11	Other	0	1.0000	0	0	0
12	Total Transmission	2,523		2,570	0	2,570
Distribution						
13	Labor	672,040	1.0352	695,696	(10,012)	685,684
14	Materials & Supplies	1,607,211	1.0191	1,637,950	(103,656)	1,534,294
15	Other	0	1.0000	0	0	0
16	Total Distribution	2,279,251		2,333,646	(113,668)	2,219,978
Customer Accounts						
17	Labor	138,161	1.0328	142,693	4,239	146,931
18	Materials & Supplies	97,816	1.0208	99,850	7,185	107,035
19	Other	0	1.0000	0	0	0
20	Total Customer Accounts (Excluding Uncollectibles)	235,977		242,543	11,423	253,966
Customer Service						
21	Labor	0	1.0328	0	0	0
22	Materials & Supplies	0	1.0208	0	0	0
23	Other	0	1.0000	0	0	0
24	Total Customer Service	0		0	0	0
Administrative & General						
25	Labor	221,105	1.0328	228,358	17,778	246,136
26	Materials & Supplies	812,194	1.0208	829,083	8,730	837,813
27	Other	119,547	1.0000	119,547	8,526	128,072
28	Medical	125,642	1.0461	131,436	8,474	139,910
29	Wage-Related	34,811	1.0328	35,953	2,171	38,123
30	Total Admin & General (Excluding Franchises)	1,313,299		1,344,376	45,679	1,390,055
Other						
31	Labor	0	1.0352	0	0	0
32	Materials & Supplies	0	1.0000	0	0	0
33	Other	(2,407)	1.0000	(2,407)	0	(2,407)
34	Total Other Adjustments	(2,407)		(2,407)	0	(2,407)
35	Total Labor Excl Wage-Related A&G	1,031,848		1,067,307	12,005	1,079,312
36	Wage-Related Administrative & General	34,811		35,953	2,171	38,123
37	Total Labor	1,066,659		1,103,260	14,176	1,117,436
38	Total Materials & Supplies	2,519,203		2,568,893	(87,742)	2,481,151
39	Total Other	117,139		117,139	8,526	125,665
40	Total Medical	125,642		131,436	8,474	139,910
41	Total Operating & Maintenance Expenses (Excl F&U)	3,828,643		3,920,728	(56,566)	3,864,162
42	Increase			92,085	(56,566)	35,519
43	Uncollectibles			279	(172)	108
44	Franchises			710	(436)	274
45	Total Increase Including Uncollectibles & Franchises			93,074	(57,174)	35,900

**TABLE 2-8
RO AT PROPOSED RATES
GAS DISTRIBUTION
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Description	Test	Attrition Year		Attrition Year		Attrition Year	
		Year	2024		2025		2026	
		2023	Increase	Total	Increase	Total	Increase	Total
		(A)	(B)	(C)	(D)	(E)	(F)	(G)
REVENUE:								
1	Revenue Collected in Rates	2,864,437	227,175	3,091,612	278,021	3,369,633	289,233	3,658,866
2	Plus Other Operating Revenue	33,586	-	33,586	-	33,586	-	33,586
3	Total Operating Revenue	2,898,023	227,175	3,125,198	278,021	3,403,219	289,233	3,692,452
OPERATING EXPENSES:								
4	Energy Costs	-	-	-	-	-	-	-
5	Gathering	3,130	108	3,238	112	3,350	116	3,466
6	Storage	-	-	-	-	-	-	-
7	Transmission	-	-	-	-	-	-	-
8	Distribution	596,255	18,664	614,919	19,043	633,962	19,629	653,591
9	Customer Accounts	157,389	4,497	161,886	4,531	166,418	4,890	171,307
10	Uncollectibles	8,122	637	8,759	779	9,538	811	10,348
11	Customer Services	-	-	-	-	-	-	-
12	Administrative and General	346,206	8,596	354,801	34,426	389,227	40,107	429,334
13	Franchise & SFGR Tax Requirement	27,526	2,158	29,684	2,641	32,324	2,747	35,072
14	Amortization	-	-	-	-	-	-	-
15	Wage Change Impacts	-	-	-	-	-	-	-
16	Other Price Change Impacts	-	-	-	-	-	-	-
17	Other Adjustments	(1,197)	-	(1,197)	-	(1,197)	-	(1,197)
18	Subtotal Expenses:	1,137,431	34,659	1,172,090	61,532	1,233,622	68,299	1,301,921
TAXES:								
19	Superfund	-	-	-	-	-	-	-
20	Property	120,422	20,425	140,847	16,517	157,364	16,344	173,708
21	Payroll	38,130	1,251	39,381	1,292	40,672	1,334	42,007
22	Business	387	-	387	-	387	-	387
23	Other	7,288	-	7,288	-	7,288	-	7,288
24	State Corporation Franchise	29,296	9,421	38,717	10,484	49,200	11,060	60,261
25	Federal Income	60,728	4,272	65,000	12,138	77,139	11,370	88,509
26	Total Taxes	256,252	35,369	291,620	40,431	332,051	40,108	372,159
27	Depreciation	741,116	102,923	844,040	125,129	969,168	133,599	1,102,768
28	Decommissioning	-	-	-	-	-	-	-
29	Other Decommissioning	-	-	-	-	-	-	-
30	Total Operating Expenses	2,134,798	172,951	2,307,749	227,092	2,534,841	242,006	2,776,848
31	Net for Return	763,224	54,224	817,448	50,929	868,377	47,227	915,604
32	Rate Base	10,398,151	738,751	11,136,902	693,857	11,830,759	643,418	12,474,177
RATE OF RETURN:								
33	On Rate Base	7.34%	7.34%	7.34%	7.34%	7.34%	7.34%	7.34%
34	On Equity	10.25%	10.25%	10.25%	10.25%	10.25%	10.25%	10.25%

**TABLE 2-9
GAS DISTRIBUTION
ATTRITION YEAR 2024 EXPENSES
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Description	2023		2024		Expense Estimate
		Escalation Basis	Escalation Factor	Base Estimate	Adjustments	
		(A)	(B)	(C)	(D)	
Gathering						
1	Labor	2,974	1.0352	3,078	0	3,078
2	Materials & Supplies	157	1.0234	160	0	160
3	Other	0	1.0000	0	0	0
4	Total Gathering	3,130		3,238	0	3,238
Storage						
5	Labor	0	1.0352	0	0	0
6	Materials & Supplies	0	1.0191	0	0	0
7	Other	0	1.0000	0	0	0
8	Total Storage	0		0	0	0
Transmission						
9	Labor	0	1.0352	0	0	0
10	Materials & Supplies	0	1.0234	0	0	0
11	Other	0	1.0000	0	0	0
12	Total Transmission	0		0	0	0
Distribution						
13	Labor	381,954	1.0352	395,399	0	395,399
14	Materials & Supplies	214,301	1.0244	219,520	0	219,520
15	Other	0	1.0000	0	0	0
16	Total Distribution	596,255		614,919	0	614,919
Customer Accounts						
17	Labor	92,253	1.0328	95,279	0	95,279
18	Materials & Supplies	65,137	1.0226	66,608	0	66,608
19	Other	0	1.0000	0	0	0
20	Total Customer Accounts (Excluding Uncollectibles)	157,389		161,886	0	161,886
Customer Service						
21	Labor	0	1.0328	0	0	0
22	Materials & Supplies	0	1.0226	0	0	0
23	Other	0	1.0000	0	0	0
24	Total Customer Service	0		0	0	0
Administrative & General						
25	Labor	102,244	1.0328	105,598	16	105,613
26	Materials & Supplies	117,665	1.0226	120,323	20	120,343
27	Other	53,058	1.0000	53,058	(934)	52,124
28	Medical	56,931	1.0461	59,556	309	59,865
29	Wage-Related	16,307	1.0328	16,842	14	16,856
30	Total Admin & General (Excluding Franchises)	346,206		355,377	(576)	354,801
Other						
31	Labor	0	1.0352	0	0	0
32	Materials & Supplies	0	1.0000	0	0	0
33	Other	(1,197)	1	(1,197)	0	(1,197)
34	Total Other Adjustments	(1,197)		(1,197)	0	(1,197)
35	Total Labor Excl Wage-Related A&G	579,424		599,353	16	599,369
36	Wage-Related Administrative & General	16,307		16,842	14	16,856
37	Total Labor	595,732		616,196	30	616,225
38	Total Materials & Supplies	397,260		406,611	20	406,631
39	Total Other	51,860		51,860	(934)	50,926
40	Total Medical	56,931		59,556	309	59,865
41	Total Operating & Maintenance Expenses (Excl F&U)	1,101,783		1,134,223	(576)	1,133,647
42	Increase			32,440	(576)	31,865
43	Uncollectibles			92	(2)	90
44	Franchises			312	(6)	306
45	Total Increase Including Uncollectibles & Franchises			32,844	(583)	32,261

**TABLE 2-10
GAS DISTRIBUTION
ATTRITION YEAR 2025 EXPENSES
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Description	2024		2025		Expense Estimate
		Escalation Basis	Escalation Factor	Base Estimate	Adjustments	
		(A)	(B)	(C)	(D)	
Gathering						
1	Labor	3,078	1.0352	3,187	0	3,187
2	Materials & Supplies	160	1.0231	164	0	164
3	Other	0	1.0000	0	0	0
4	Total Gathering	3,238		3,350	0	3,350
Storage						
5	Labor	0	1.0352	0	0	0
6	Materials & Supplies	0	1.0186	0	0	0
7	Other	0	1.0000	0	0	0
8	Total Storage	0		0	0	0
Transmission						
9	Labor	0	1.0352	0	0	0
10	Materials & Supplies	0	1.0231	0	0	0
11	Other	0	1.0000	0	0	0
12	Total Transmission	0		0	0	0
Distribution						
13	Labor	395,399	1.0352	409,317	0	409,317
14	Materials & Supplies	219,520	1.0233	224,645	0	224,645
15	Other	0	1.0000	0	0	0
16	Total Distribution	614,919		633,962	0	633,962
Customer Accounts						
17	Labor	95,279	1.0328	98,404	0	98,404
18	Materials & Supplies	66,608	1.0211	68,014	0	68,014
19	Other	0	1.0000	0	0	0
20	Total Customer Accounts (Excluding Uncollectibles)	161,886		166,418	0	166,418
Customer Service						
21	Labor	0	1.0328	0	0	0
22	Materials & Supplies	0	1.0211	0	0	0
23	Other	0	1.0000	0	0	0
24	Total Customer Service	0		0	0	0
Administrative & General						
25	Labor	105,613	1.0328	109,077	7,741	116,818
26	Materials & Supplies	120,343	1.0211	122,883	9,095	131,978
27	Other	52,124	1.0000	52,124	3,534	55,658
28	Medical	59,865	1.0461	62,625	3,756	66,381
29	Wage-Related	16,856	1.0328	17,409	982	18,392
30	Total Admin & General (Excluding Franchises)	354,801		364,119	25,108	389,227
Other						
31	Labor	0	1.0352	0	0	0
32	Materials & Supplies	0	1.0000	0	0	0
33	Other	(1,197)	1.0000	(1,197)	0	(1,197)
34	Total Other Adjustments	(1,197)		(1,197)	0	(1,197)
35	Total Labor Excl Wage-Related A&G	599,369		619,985	7,741	627,725
36	Wage-Related Administrative & General	16,856		17,409	982	18,392
37	Total Labor	616,225		637,394	8,723	646,117
38	Total Materials & Supplies	406,631		415,706	9,095	424,801
39	Total Other	50,926		50,926	3,534	54,460
40	Total Medical	59,865		62,625	3,756	66,381
41	Total Operating & Maintenance Expenses (Excl F&U)	1,133,647		1,166,652	25,108	1,191,760
42	Increase			33,005	25,108	58,113
43	Uncollectibles			94	71	165
44	Franchises			317	241	559
45	Total Increase Including Uncollectibles & Franchises			33,416	25,421	58,836

**TABLE 2-11
GAS DISTRIBUTION
ATTRITION YEAR 2026 EXPENSES
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Description	2025	2026			Expense Estimate
		Escalation Basis	Escalation Factor	Base Estimate	Adjustments	
		(A)	(B)	(C)	(D)	
Gathering						
1	Labor	3,187	1.0352	3,299	0	3,299
2	Materials & Supplies	164	1.0223	168	0	168
3	Other	0	1.0000	0	0	0
4	Total Gathering	3,350		3,466	0	3,466
Storage						
5	Labor	0	1.0352	0	0	0
6	Materials & Supplies	0	1.0179	0	0	0
7	Other	0	1.0000	0	0	0
8	Total Storage	0		0	0	0
Transmission						
9	Labor	0	1.0352	0	0	0
10	Materials & Supplies	0	1.0223	0	0	0
11	Other	0	1.0000	0	0	0
12	Total Transmission	0		0	0	0
Distribution						
13	Labor	409,317	1.0352	423,725	0	423,725
14	Materials & Supplies	224,645	1.0232	229,866	0	229,866
15	Other	0	1.0000	0	0	0
16	Total Distribution	633,962		653,591	0	653,591
Customer Accounts						
17	Labor	98,404	1.0328	101,631	92	101,723
18	Materials & Supplies	68,014	1.0208	69,428	156	69,584
19	Other	0	1.0000	0	0	0
20	Total Customer Accounts (Excluding Uncollectibles)	166,418		171,060	248	171,307
Customer Service						
21	Labor	0	1.0328	0	0	0
22	Materials & Supplies	0	1.0208	0	0	0
23	Other	0	1.0000	0	0	0
24	Total Customer Service	0		0	0	0
Administrative & General						
25	Labor	116,818	1.0328	120,650	9,393	130,043
26	Materials & Supplies	131,978	1.0208	134,722	10,791	145,513
27	Other	55,658	1.0000	55,658	4,059	59,717
28	Medical	66,381	1.0461	69,442	4,477	73,919
29	Wage-Related	18,392	1.0328	18,995	1,147	20,142
30	Total Admin & General (Excluding Franchises)	389,227		399,467	29,867	429,334
Other						
31	Labor	0	1.0352	0	0	0
32	Materials & Supplies	0	1.0000	0	0	0
33	Other	(1,197)	1.0000	(1,197)	0	(1,197)
34	Total Other Adjustments	(1,197)		(1,197)	0	(1,197)
35	Total Labor Excl Wage-Related A&G	627,725		649,305	9,485	658,790
36	Wage-Related Administrative & General	18,392		18,995	1,147	20,142
37	Total Labor	646,117		668,300	10,632	678,932
38	Total Materials & Supplies	424,801		434,184	10,947	445,131
39	Total Other	54,460		54,460	4,059	58,519
40	Total Medical	66,381		69,442	4,477	73,919
41	Total Operating & Maintenance Expenses (Excl F&U)	1,191,760		1,226,387	30,114	1,256,501
42	Increase			34,627	30,114	64,741
43	Uncollectibles			98	85	184
44	Franchises			333	290	623
45	Total Increase Including Uncollectibles & Franchises			35,058	30,490	65,547

TABLE 2-12
RO AT PROPOSED RATES
ELECTRIC GENERATION
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	Test Year	Attrition Year 2024		Attrition Year 2025		Attrition Year 2026	
		2023	Increase	Total	Increase	Total	Increase	Total
		(A)	(B)	(C)	(D)	(E)	(F)	(G)
REVENUE:								
1	Revenue Collected in Rates	2,404,514	(8,094)	2,396,420	(415,979)	1,980,441	(671,492)	1,308,950
2	Plus Other Operating Revenue	13,487	-	13,487	-	13,487	-	13,487
3	Total Operating Revenue	2,418,001	(8,094)	2,409,907	(415,979)	1,993,928	(671,492)	1,322,437
OPERATING EXPENSES:								
4	Energy Costs	-	-	-	-	-	-	-
5	Production	598,849	6,887	605,737	(140,312)	465,425	(159,126)	306,299
6	Storage	-	-	-	-	-	-	-
7	Transmission	16,814	326	17,140	321	17,460	329	17,789
8	Distribution	-	-	-	-	-	-	-
9	Customer Accounts	-	-	-	-	-	-	-
10	Uncollectibles	7,254	(24)	7,229	(1,248)	5,982	(2,014)	3,967
11	Customer Services	-	-	-	-	-	-	-
12	Administrative and General	365,828	9,403	375,231	(96,411)	278,821	(119,635)	159,186
13	Franchise & SFGR Tax Requirement	18,452	(62)	18,390	(3,174)	15,216	(5,124)	10,092
14	Amortization	31,491	-	31,491	(11,827)	19,664	(19,500)	164
15	Wage Change Impacts	-	-	-	-	-	-	-
16	Other Price Change Impacts	-	-	-	-	-	-	-
17	Other Adjustments	(1,828)	-	(1,828)	(111)	(1,939)	1,939	-
18	Subtotal Expenses:	1,036,860	16,531	1,053,390	(252,762)	800,628	(303,131)	497,497
TAXES:								
19	Superfund	-	-	-	-	-	-	-
20	Property	70,707	7,109	77,817	3,324	81,141	5,727	86,868
21	Payroll	29,944	982	30,926	1,014	31,941	(19,724)	12,216
22	Business	405	-	405	-	405	(264)	141
23	Other	7,613	-	7,613	-	7,613	(4,964)	2,649
24	State Corporation Franchise	48,127	(13,036)	35,090	(17,516)	17,574	172	17,746
25	Federal Income	38,377	(17,377)	21,000	(25,263)	(4,263)	25,005	20,742
26	Total Taxes	195,172	(22,322)	172,851	(38,441)	134,410	5,953	140,362
27	Depreciation	690,913	13,951	704,864	(66,683)	638,181	(318,103)	320,078
28	Decommissioning	77,195	200	77,395	2,300	79,695	2,700	82,395
29	Nuclear Decommissioning	-	-	-	-	-	-	-
30	Total Operating Expenses	2,000,140	8,360	2,008,500	(355,586)	1,652,914	(612,582)	1,040,332
31	Net for Return	417,861	(16,454)	401,407	(60,392)	341,014	(58,910)	282,104
32	Rate Base	5,692,927	(224,171)	5,468,756	(822,786)	4,645,970	(802,584)	3,843,386
RATE OF RETURN:								
33	On Rate Base	7.34%	7.34%	7.34%	7.34%	7.34%	7.34%	7.34%
34	On Equity	10.25%	10.25%	10.25%	10.25%	10.25%	10.25%	10.25%

TABLE 2-13
ELECTRIC GENERATION
ATTRITION YEAR 2024 EXPENSES
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2023		2024		Expense Estimate
		Escalation Basis	Escalation Factor	Base Estimate	Adjustments	
		(A)	(B)	(C)	(D)	
Production						
1	Labor	344,730	1.0352	356,864	(7,353)	349,512
2	Materials & Supplies	254,119	*Note 1.0225	259,916	(3,691)	256,225
3	Other	0	1.0000	0	0	0
4	Total Production	598,849		616,780	(11,044)	605,737
Storage						
5	Labor	0	1.0352	0	0	0
6	Materials & Supplies	0	1.0191	0	0	0
7	Other	0	1.0000	0	0	0
8	Total Storage	0		0	0	0
Transmission						
9	Labor	3,499	1.0352	3,622	0	3,622
10	Materials & Supplies	13,314	1.0152	13,517	0	13,517
11	Other	0	1.0000	0	0	0
12	Total Transmission	16,814		17,140	0	17,140
Distribution						
13	Labor	0	1.0352	0	0	0
14	Materials & Supplies	0	1.0216	0	0	0
15	Other	0	1.0000	0	0	0
16	Total Distribution	0		0	0	0
Customer Accounts						
17	Labor	0	1.0328	0	0	0
18	Materials & Supplies	0	1.0226	0	0	0
19	Other	0	1.0000	0	0	0
20	Total Customer Accounts (Excluding Uncollectibles)	0		0	0	0
Customer Service						
21	Labor	0	1.0328	0	0	0
22	Materials & Supplies	0	1.0226	0	0	0
23	Other	0	1.0000	0	0	0
24	Total Customer Service	0		0	0	0
Administrative & General						
25	Labor	106,803	1.0328	110,306	16	110,323
26	Materials & Supplies	122,912	1.0226	125,688	21	125,709
27	Other	59,609	1.0000	59,609	(551)	59,058
28	Medical	59,470	1.0461	62,212	323	62,534
29	Wage-Related	17,035	1.0328	17,593	15	17,608
30	Total Admin & General (Excluding Franchises)	365,828		375,408	(177)	375,231
Other						
31	Labor	0	1.0352	0	0	0
32	Materials & Supplies	0	1.0000	0	0	0
33	Other	(1,828)	1.0000	(1,828)	0	(1,828)
34	Total Other Adjustments	(1,828)		(1,828)	0	(1,828)
35	Total Labor Excl Wage-Related A&G	455,032		470,793	(7,336)	463,457
36	Wage-Related Administrative & General	17,035		17,593	15	17,608
37	Total Labor	472,067		488,387	(7,322)	481,065
38	Total Materials & Supplies	390,346		399,121	(3,670)	395,451
39	Total Other	57,781		57,781	(551)	57,230
40	Total Medical	59,470		62,212	323	62,534
41	Total Operating & Maintenance Expenses (Excl F&U)	979,663		1,007,500	(11,221)	996,280
42	Increase			27,837	(11,221)	16,617
43	Uncollectibles			84	(34)	50
44	Franchises			214	(86)	128
45	Total Increase Including Uncollectibles & Franchises			28,136	(11,341)	16,795

*Note: The escalation rate reflects a composite escalation factor for fossil, hydro and nuclear.
Different escalation rates were applied to fossil, hydro and nuclear Production Materials & Supplies.

TABLE 2-14
ELECTRIC GENERATION
ATTRITION YEAR 2025 EXPENSES
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2024		2025		Expense Estimate
		Escalation Basis	Escalation Factor	Base Estimate	Adjustments	
		(A)	(B)	(C)	(D)	
Production						
1	Labor	349,512	1.0352	361,815	(106,632)	255,183
2	Materials & Supplies	256,225	*Note 1.0214	261,778	(51,537)	210,242
3	Other	0	1.0000	0	0	0
4	Total Production	605,737		623,593	(158,168)	465,425
Storage						
5	Labor	0	1.0352	0	0	0
6	Materials & Supplies	0	1.0186	0	0	0
7	Other	0	1.0000	0	0	0
8	Total Storage	0		0	0	0
Transmission						
9	Labor	3,622	1.0352	3,750	0	3,750
10	Materials & Supplies	13,517	1.0143	13,710	0	13,710
11	Other	0	1.0000	0	0	0
12	Total Transmission	17,140		17,460	0	17,460
Distribution						
13	Labor	0	1.0352	0	0	0
14	Materials & Supplies	0	1.0198	0	0	0
15	Other	0	1.0000	0	0	0
16	Total Distribution	0		0	0	0
Customer Accounts						
17	Labor	0	1.0328	0	0	0
18	Materials & Supplies	0	1.0211	0	0	0
19	Other	0	1.0000	0	0	0
20	Total Customer Accounts (Excluding Uncollectibles)	0		0	0	0
Customer Service						
21	Labor	0	1.0328	0	0	0
22	Materials & Supplies	0	1.0211	0	0	0
23	Other	0	1.0000	0	0	0
24	Total Customer Service	0		0	0	0
Administrative & General						
25	Labor	110,323	1.0328	113,941	(31,696)	82,245
26	Materials & Supplies	125,709	1.0211	128,363	(35,444)	92,918
27	Other	59,058	1.0000	59,058	(15,085)	43,973
28	Medical	62,534	1.0461	65,418	(18,682)	46,736
29	Wage-Related	17,608	1.0328	18,186	(5,237)	12,949
30	Total Admin & General (Excluding Franchises)	375,231		384,965	(106,144)	278,821
Other						
31	Labor	0	1.0352	0	0	0
32	Materials & Supplies	0	1.0000	0	0	0
33	Other	(1,828)	1.0000	(1,828)	(111)	(1,939)
34	Total Other Adjustments	(1,828)		(1,828)	(111)	(1,939)
35	Total Labor Excl Wage-Related A&G	463,457		479,506	(138,328)	341,178
36	Wage-Related Administrative & General	17,608		18,186	(5,237)	12,949
37	Total Labor	481,065		497,692	(143,564)	354,127
38	Total Materials & Supplies	395,451		403,851	(86,981)	316,870
39	Total Other	57,230		57,230	(15,196)	42,034
40	Total Medical	62,534		65,418	(18,682)	46,736
41	Total Operating & Maintenance Expenses (Excl F&U)	996,280		1,024,190	(264,424)	759,767
42	Increase			27,911	(264,424)	(236,513)
43	Uncollectibles			85	(802)	(717)
44	Franchises			215	(2,040)	(1,824)
45	Total Increase Including Uncollectibles & Franchises			28,210	(267,265)	(239,054)

*Note: The escalation rate reflects a composite escalation factor for fossil, hydro and nuclear.
Different escalation rates were applied to fossil, hydro and nuclear Production Materials & Supplies.

TABLE 2-15
ELECTRIC GENERATION
ATTRITION YEAR 2026 EXPENSES
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2025	2026			Expense Estimate
		Escalation Basis (A)	Escalation Factor (B)	Base Estimate (C)	Adjustments (D)	
Production						
1	Labor	255,183	1.0352	264,166	(122,063)	142,103
2	Materials & Supplies	210,242	*Note 1.0211	214,770	(50,574)	164,196
3	Other	0	1.0000	0	0	0
4	Total Production	465,425		478,936	(172,637)	306,299
Storage						
5	Labor	0	1.0352	0	0	0
6	Materials & Supplies	0	1.0179	0	0	0
7	Other	0	1.0000	0	0	0
8	Total Storage	0		0	0	0
Transmission						
9	Labor	3,750	1.0352	3,882	0	3,882
10	Materials & Supplies	13,710	1.0144	13,907	0	13,907
11	Other	0	1.0000	0	0	0
12	Total Transmission	17,460		17,789	0	17,789
Distribution						
13	Labor	0	1.0352	0	0	0
14	Materials & Supplies	0	1.0191	0	0	0
15	Other	0	1.0000	0	0	0
16	Total Distribution	0		0	0	0
Customer Accounts						
17	Labor	0	1.0328	0	0	0
18	Materials & Supplies	0	1.0208	0	0	0
19	Other	0	1.0000	0	0	0
20	Total Customer Accounts (Excluding Uncollectibles)	0		0	0	0
Customer Service						
21	Labor	0	1.0328	0	0	0
22	Materials & Supplies	0	1.0208	0	0	0
23	Other	0	1.0000	0	0	0
24	Total Customer Service	0		0	0	0
Administrative & General						
25	Labor	82,245	1.0328	84,943	(37,672)	47,271
26	Materials & Supplies	92,918	1.0208	94,851	(41,956)	52,894
27	Other	43,973	1.0000	43,973	(19,143)	24,830
28	Medical	46,736	1.0461	48,891	(22,021)	26,870
29	Wage-Related	12,949	1.0328	13,373	(6,052)	7,322
30	Total Admin & General (Excluding Franchises)	278,821		286,030	(126,844)	159,186
Other						
31	Labor	0	1.0352	0	0	0
32	Materials & Supplies	0	1.0000	0	0	0
33	Other	(1,939)	1.0000	(1,939)	1,939	0
34	Total Other Adjustments	(1,939)		(1,939)	1,939	0
35	Total Labor Excl Wage-Related A&G	341,178		352,990	(159,735)	193,256
36	Wage-Related Administrative & General	12,949		13,373	(6,052)	7,322
37	Total Labor	354,127		366,364	(165,787)	200,577
38	Total Materials & Supplies	316,870		323,528	(92,531)	230,997
39	Total Other	42,034		42,034	(17,204)	24,830
40	Total Medical	46,736		48,891	(22,021)	26,870
41	Total Operating & Maintenance Expenses (Excl F&U)	759,767		780,816	(297,542)	483,274
42	Increase			21,050	(297,542)	(276,493)
43	Uncollectibles			64	(902)	(838)
44	Franchises			162	(2,295)	(2,133)
45	Total Increase Including Uncollectibles & Franchises			21,276	(300,739)	(279,464)

*Note: The escalation rate reflects a composite escalation factor for fossil, hydro and nuclear.
Different escalation rates were applied to fossil, hydro and nuclear Production Materials & Supplies.

**TABLE 2-16
RO AT PROPOSED RATES
GAS TRANSMISSION AND STORAGE
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Description	Test Year	Attrition Year 2024		Attrition Year 2025		Attrition Year 2026	
		2023	Increase	Total	Increase	Total	Increase	Total
		(A)	(B)	(C)	(D)	(E)	(F)	(G)
	REVENUE:		13.7%		5.8%		6.4%	
1	Revenue Collected in Rates	1,841,672	286,493	2,128,165	144,764	2,272,929	166,712	2,439,641
2	Plus Other Operating Revenue	10,995	-	10,995	-	10,995	-	10,995
3	Total Operating Revenue	1,852,667	286,493	2,139,160	144,764	2,283,923	166,712	2,450,636
	OPERATING EXPENSES:							
4	Energy Costs	-	-	-	-	-	-	-
5	Gathering	-	-	-	-	-	-	-
6	Storage	44,160	5,206	49,366	2,688	52,054	22,427	74,481
7	Transmission	658,593	18,204	676,798	18,581	695,379	18,770	714,149
8	Distribution	-	-	-	-	-	-	-
9	Customer Accounts	-	-	-	-	-	-	-
10	Uncollectibles	5,192	803	5,995	406	6,401	467	6,868
11	Customer Services	-	-	-	-	-	-	-
12	Administrative and General	167,164	4,491	171,655	16,551	188,206	19,276	207,482
13	Franchise & SFGR Tax Requirement	17,597	2,721	20,318	1,375	21,693	1,583	23,277
14	Amortization	-	-	-	-	-	-	-
15	Wage Change Impacts	-	-	-	-	-	-	-
16	Other Price Change Impacts	-	-	-	-	-	-	-
17	Other Adjustments	350	-	350	-	350	-	350
18	Subtotal Expenses:	893,057	31,426	924,482	39,601	964,083	62,523	1,026,606
	TAXES:							
19	Superfund	-	-	-	-	-	-	-
20	Property	103,915	15,218	119,133	12,635	131,768	11,884	143,652
21	Payroll	19,788	649	20,437	670	21,107	692	21,800
22	Business	185	-	185	-	185	-	185
23	Other	3,473	-	3,473	-	3,473	-	3,473
24	State Corporation Franchise	(4,822)	15,339	10,518	546	11,063	1,123	12,187
25	Federal Income	55,386	26,435	81,821	2,993	84,814	9,214	94,028
26	Total Taxes	177,925	57,642	235,567	16,844	252,411	22,913	275,324
27	Depreciation	287,553	80,049	367,603	37,345	404,948	36,228	441,176
28	Decommissioning	(48,871)	51,912	3,040	-	3,040	-	3,040
29	Other Decommissioning	-	-	-	-	-	-	-
30	Total Operating Expenses	1,309,664	221,028	1,530,692	93,790	1,624,482	121,664	1,746,146
31	Net for Return	543,003	65,465	608,468	50,974	659,441	45,048	704,489
32	Rate Base	7,397,856	891,896	8,289,752	694,465	8,984,216	613,735	9,597,951
	RATE OF RETURN:							
33	On Rate Base	7.34%	7.34%	7.34%	7.34%	7.34%	7.34%	7.34%
34	On Equity	10.25%	10.25%	10.25%	10.25%	10.25%	10.25%	10.25%

**TABLE 2-17
GAS TRANSMISSION AND STORAGE
ATTRITION YEAR 2024 EXPENSES
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Description	2023	2024			Expense Estimate (E)
		Escalation Basis (A)	Escalation Factor (B)	Base Estimate (C)	Adjustments (D)	
Gathering						
1	Labor	0	1.0352	0	0	0
2	Materials & Supplies	0	1.0234	0	0	0
3	Other	0	1.0000	0	0	0
4	Total Gathering	0		0	0	0
Storage						
5	Labor	15,634	1.0352	16,184	782	16,966
6	Materials & Supplies	28,526	1.0191	29,069	3,330	32,400
7	Other	0	1.0000	0	0	0
8	Total Storage	44,160		45,254	4,112	49,366
Transmission						
9	Labor	236,332	1.0352	244,651	0	244,651
10	Materials & Supplies	422,261	1.0234	432,147	0	432,147
11	Other	0	1.0000	0	0	0
12	Total Transmission	658,593		676,798	0	676,798
Distribution						
13	Labor	0	1.0352	0	0	0
14	Materials & Supplies	0	1.0244	0	0	0
15	Other	0	1.0000	0	0	0
16	Total Distribution	0		0	0	0
Customer Accounts						
17	Labor	0	1.0328	0	0	0
18	Materials & Supplies	0	1.0226	0	0	0
19	Other	0	1.0000	0	0	0
20	Total Customer Accounts (Excluding Uncollectibles)	0		0	0	0
Customer Service						
21	Labor	0	1.0328	0	0	0
22	Materials & Supplies	0	1.0226	0	0	0
23	Other	0	1.0000	0	0	0
24	Total Customer Service	0		0	0	0
Administrative & General						
25	Labor	48,731	1.0328	50,329	7	50,337
26	Materials & Supplies	56,081	1.0226	57,347	9	57,357
27	Other	27,446	1.0000	27,446	(51)	27,395
28	Medical	27,134	1.0461	28,385	147	28,532
29	Wage-Related	7,772	1.0328	8,027	7	8,034
30	Total Admin & General (Excluding Franchises)	167,164		171,535	120	171,655
Other						
31	Labor	0	1.0352	0	0	0
32	Materials & Supplies	0	1.0000	0	0	0
33	Other	350	1.0000	350	0	350
34	Total Other Adjustments	350		350	0	350
35	Total Labor Excl Wage-Related A&G	300,697		311,164	790	311,954
36	Wage-Related Administrative & General	7,772		8,027	7	8,034
37	Total Labor	308,469		319,192	796	319,988
38	Total Materials & Supplies	506,868		518,564	3,340	521,903
39	Total Other	27,796		27,796	(51)	27,745
40	Total Medical	27,134		28,385	147	28,532
41	Total Operating & Maintenance Expenses (Excl F&U)	870,268		893,937	4,232	898,169
42	Increase			23,669	4,232	27,901
43	Uncollectibles			67	12	79
44	Franchises			227	41	268
45	Total Increase Including Uncollectibles & Franchises			23,964	4,285	28,249

TABLE 2-18
GAS TRANSMISSION AND STORAGE
ATTRITION YEAR 2025 EXPENSES
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2024		2025		Expense Estimate
		Escalation Basis	Escalation Factor	Base Estimate	Adjustments	
		(A)	(B)	(C)	(D)	
Gathering						
1	Labor	0	1.0352	0	0	0
2	Materials & Supplies	0	1.0231	0	0	0
3	Other	0	1.0000	0	0	0
4	Total Gathering	0		0	0	0
Storage						
5	Labor	16,966	1.0352	17,563	240	17,804
6	Materials & Supplies	32,400	1.0186	33,002	1,247	34,250
7	Other	0	1.0000	0	0	0
8	Total Storage	49,366		50,566	1,488	52,054
Transmission						
9	Labor	244,651	1.0352	253,263	0	253,263
10	Materials & Supplies	432,147	1.0231	442,116	0	442,116
11	Other	0	1.0000	0	0	0
12	Total Transmission	676,798		695,379	0	695,379
Distribution						
13	Labor	0	1.0352	0	0	0
14	Materials & Supplies	0	1.0233	0	0	0
15	Other	0	1.0000	0	0	0
16	Total Distribution	0		0	0	0
Customer Accounts						
17	Labor	0	1.0328	0	0	0
18	Materials & Supplies	0	1.0211	0	0	0
19	Other	0	1.0000	0	0	0
20	Total Customer Accounts (Excluding Uncollectibles)	0		0	0	0
Customer Service						
21	Labor	0	1.0328	0	0	0
22	Materials & Supplies	0	1.0211	0	0	0
23	Other	0	1.0000	0	0	0
24	Total Customer Service	0		0	0	0
Administrative & General						
25	Labor	50,337	1.0328	51,988	3,689	55,677
26	Materials & Supplies	57,357	1.0211	58,568	4,335	62,902
27	Other	27,395	1.0000	27,395	1,827	29,223
28	Medical	28,532	1.0461	29,848	1,790	31,638
29	Wage-Related	8,034	1.0328	8,298	468	8,766
30	Total Admin & General (Excluding Franchises)	171,655		176,096	12,110	188,206
Other						
31	Labor	0	1.0352	0	0	0
32	Materials & Supplies	0	1.0000	0	0	0
33	Other	350	1.0000	350	0	350
34	Total Other Adjustments	350		350	0	350
35	Total Labor Excl Wage-Related A&G	311,954		322,814	3,930	326,744
36	Wage-Related Administrative & General	8,034		8,298	468	8,766
37	Total Labor	319,988		331,111	4,398	335,509
38	Total Materials & Supplies	521,903		533,686	5,582	539,268
39	Total Other	27,745		27,745	1,827	29,573
40	Total Medical	28,532		29,848	1,790	31,638
41	Total Operating & Maintenance Expenses (Excl F&U)	898,169		922,391	13,598	935,989
42	Increase			24,222	13,598	37,820
43	Uncollectibles			69	39	107
44	Franchises			233	131	364
45	Total Increase Including Uncollectibles & Franchises			24,524	13,767	38,291

**TABLE 2-19
GAS TRANSMISSION AND STORAGE
ATTRITION YEAR 2026 EXPENSES
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Description	2025	2026			Expense Estimate
		Escalation Basis (A)	Escalation Factor (B)	Base Estimate (C)	Adjustments (D)	
Gathering						
1	Labor	0	1.0352	0	0	0
2	Materials & Supplies	0	1.0223	0	0	0
3	Other	0	1.0000	0	0	0
4	Total Gathering	0		0	0	0
Storage						
5	Labor	17,804	1.0352	18,431	4,198	22,628
6	Materials & Supplies	34,250	1.0179	34,863	16,989	51,853
7	Other	0	1.0000	0	0	0
8	Total Storage	52,054		53,294	21,187	74,481
Transmission						
9	Labor	253,263	1.0352	262,177	0	262,177
10	Materials & Supplies	442,116	1.0223	451,971	0	451,971
11	Other	0	1.0000	0	0	0
12	Total Transmission	695,379		714,149	0	714,149
Distribution						
13	Labor	0	1.0352	0	0	0
14	Materials & Supplies	0	1.0232	0	0	0
15	Other	0	1.0000	0	0	0
16	Total Distribution	0		0	0	0
Customer Accounts						
17	Labor	0	1.0328	0	0	0
18	Materials & Supplies	0	1.0208	0	0	0
19	Other	0	1.0000	0	0	0
20	Total Customer Accounts (Excluding Uncollectibles)	0		0	0	0
Customer Service						
21	Labor	0	1.0328	0	0	0
22	Materials & Supplies	0	1.0208	0	0	0
23	Other	0	1.0000	0	0	0
24	Total Customer Service	0		0	0	0
Administrative & General						
25	Labor	55,677	1.0328	57,503	4,477	61,980
26	Materials & Supplies	62,902	1.0208	64,210	5,143	69,353
27	Other	29,223	1.0000	29,223	2,095	31,318
28	Medical	31,638	1.0461	33,097	2,134	35,231
29	Wage-Related	8,766	1.0328	9,053	547	9,600
30	Total Admin & General (Excluding Franchises)	188,206		193,087	14,395	207,482
Other						
31	Labor	0	1.0352	0	0	0
32	Materials & Supplies	0	1.0000	0	0	0
33	Other	350	1.0000	350	0	350
34	Total Other Adjustments	350		350	0	350
35	Total Labor Excl Wage-Related A&G	326,744		338,111	8,674	346,786
36	Wage-Related Administrative & General	8,766		9,053	547	9,600
37	Total Labor	335,509		347,165	9,221	356,386
38	Total Materials & Supplies	539,268		551,045	22,132	573,177
39	Total Other	29,573		29,573	2,095	31,668
40	Total Medical	31,638		33,097	2,134	35,231
41	Total Operating & Maintenance Expenses (Excl F&U)	935,989		960,880	35,582	996,462
42	Increase			24,891	35,582	60,472
43	Uncollectibles			71	101	172
44	Franchises			239	342	582
45	Total Increase Including Uncollectibles & Franchises			25,201	36,025	61,226

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
RATE BASE GROWTH IN ATTRITION YEARS
AND RELATED COSTS
[INCLUDES ERRATA THROUGH FEBRUARY 28, 2022 AND
FEBRUARY 28, 2022 SUPPLEMENTAL TESTIMONY]

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
RATE BASE GROWTH IN ATTRITION YEARS
AND RELATED COSTS

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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **CHAPTER 3**
3 **RATE BASE GROWTH IN ATTRITION YEARS**
4 **AND RELATED COSTS**

5 **A. Introduction**

6 **1. Scope and Purpose**

7 The purpose of this chapter is to present Pacific Gas and Electric
8 Company's (PG&E or the Company) calculation of the electric and gas
9 distribution, electric generation (EG), and Gas Transmission and Storage
10 (GT&S) capital cost components of the attrition adjustments for 2024, 2025,
11 and 2026, in accordance with the Post Test-Year Ratemaking (PTYR)
12 mechanism discussed in Chapters 1 and 2. The capital cost portion
13 includes the costs associated with the growth in rate base,¹ associated
14 income taxes, deferred taxes, property taxes and depreciation. All of these
15 costs can be determined on a fixed basis, because capital additions are
16 proposed to be determined based on test-year (TY) plant additions plus
17 escalation, except for the following:

- 18 • Capital additions in nuclear generation, hydroelectric generation
19 (Hydro), corporate real estate strategy and services (CRESS), and gas
20 storage due to uneven forecast capital additions;
- 21 • Capital additions in electric distribution's system hardening and the
22 community rebuild program (referred to as "system hardening") as a
23 result of PG&E's February 25, 2022 supplemental testimony and
24 forecasts to underground additional miles of electric distribution
25 powerlines to reduce wildfire risks;
- 26 • Forecast retirements for certain common and general Federal
27 Energy Regulatory Commission (FERC) accounts that are based on a
28 predetermined schedule that reflects authorized service lives
29 (vintage retirements);² and

1 Rate base growth, in general, is caused by increases in plant additions that are greater than depreciation.

2 See Exhibit (PG&E-10), Ch. 10 for a discussion of vintage retirements.

- Other rate base PTY revenue adjustments in gas storage, gas distribution, and Diablo Canyon Power Plant (DCPP).

The reasons for using these estimating methods are discussed below in Sections B and C.

2. Summary of Request

PG&E requests that the California Public Utilities Commission (CPUC or Commission) adopt the capital cost elements of attrition set forth in this chapter, which includes rate base growth, increases in property taxes, depreciation and related income tax expense. Accelerated tax depreciation has greatly inflated deferred taxes (a reduction to rate base) coming into the TY and will be reversing in future periods. As part of the computation of rate base growth, PG&E's Post Test-Year (PTY) mechanism includes adjustments that reflect the reversal of deferred taxes during the attrition period. This methodology to reflect the capital cost elements for attrition in the computation of the base revenue increase for 2024, 2025, and 2026 is described in Sections B through E below, and applies to electric and gas distribution, EG, and GT&S.

For 2024, 2025, and 2026, the Commission should adopt the changes from PG&E's 2023 rate base forecast as shown in Table 3-1 below.

**TABLE 3-1
RATE BASE CHANGES
(MILLIONS OF NOMINAL DOLLARS)**

Line No.	Description	2023 Weighted Average Forecast	2024 Weighted Average Increase/ (Decrease)	2025 Weighted Average Increase/ (Decrease)	2026 Weighted Average Increase/ (Decrease)
1	Electric Distribution	\$25,690	\$3,250	\$3,825	\$4,080
2	Gas Distribution	10,398	739	694	643
3	EG	5,693	(224)	(823)	(803)
4	GT&S	7,398	892	694	614
5	Total	\$49,179	\$4,657	\$4,390	\$4,534

PG&E also requests that the Commission adopt the other rate base PTY revenue adjustments in gas storage, gas distribution, and DCPP, summarized in Table 3-3.

1 **3. Support for Request**

2 PG&E’s request for gas and electric distribution, EG, GT&S rate base
3 changes under the PTYR mechanism is fully justified and
4 reasonable because:

- 5 • An attrition mechanism is necessary to provide PG&E a reasonable
6 opportunity to recover its increased cost of providing service between
7 rate cases;
- 8 • PG&E routinely invests capital in its gas and electric distribution
9 systems, generation assets, GT&S systems, and common utility facilities
10 to meet load growth, connect new customers, and maintain safe and
11 reliable service. This investment generally exceeds the amount of
12 depreciation expense for these facilities, resulting in annual increases in
13 rate base, as well as corresponding increases to depreciation and
14 property taxes; and
- 15 • PG&E’s method of computing the change in rate base and related costs
16 provides a reasonable measure of the increases required to maintain
17 safety and reliability of existing assets and to meet the demands of new
18 business and load growth.

19 **4. Organization of the Remainder of This Chapter**

20 The remaining sections of this chapter are organized as follows:

- 21 • Section B – Capital Additions and Retirements Computation for 2024
22 through 2026;
- 23 • Section C – Other Rate Base PTY Adjustments for 2024 through 2026;
- 24 • Section D – Separating Rate Base into Unbundled Cost Categories;
- 25 • Section E – Rate Base Growth and Related Costs; and
- 26 • Section F – Conclusion.

27 **B. Capital Additions and Retirements Computation for 2024 Through 2026**

28 PG&E proposes that the PTY capital additions forecast for 2024, 2025, and
29 2026 is equal to the adopted 2023 TY net capital additions plus escalation,
30 except for:

- 1 • The following lines of business where we propose to use bottom-up³
2 forecasts of PTY due to uneven forecast capital additions in attrition years
3 and/or TY capital expenditures amount exceed the PTY bottom-up
4 forecasts:
- 5 1) Nuclear generation: Retirement of DCPD by 2025 results in limited
6 capital expenditures forecasts in attrition years and none in 2026;
7 2) Hydro: Forecast costs necessary for relicensing hydro facilities,
8 new/amended FERC license implementation work, and risk mitigations
9 associated with the Large Uncontrolled Water Release risk, tend to
10 follow uneven cost trajectories.⁴ PG&E is forecasting a large reduction
11 in capital expenditures of approximately \$105 million from 2023 to 2026;
12 3) CRESS: inclusion of significant forecast addition of new Oakland
13 headquarters building purchase in 2023;
14 4) Gas storage: PG&E's Natural Gas Storage Strategy (NGSS), which
15 was adopted in the 2019 GT&S Rate Case, forecasts for higher capital
16 investments through year 2024 to meet recent regulation changes
17 required under the Pipeline and Hazardous Materials Safety
18 Administration (PHMSA) and California Department of Conservation,
19 Geologic Energy Management Division (CalGEM), following the Aliso
20 Canyon event in Southern California in 2015.⁵ Forecast capital
21 spending in years 2025 and 2026 are less than TY; and
22 5) Electric distribution: As described in PG&E's supplemental testimony
23 served on February 25, 2022, PG&E has updated the forecast to reflect
24 the Utility's proposal to underground additional miles of electric
25 distribution powerlines to reduce wildfire risk. As a result of this
26 forecast update, PG&E proposes a "bottom-up" capital forecast for
27 system hardening.⁶

3 The bottom-up forecast refers to the 2024, 2025 and 2026 capital forecast presented by the witnesses in Exhibits (PG&E-3) through (PG&E-9) of PG&E's 2023 GRC Application.

4 Exhibit (PG&E-5), Ch. 4, Hydro Operations Costs.

5 Exhibit (PG&E-3), Ch. 7, Asset Family Storage, provides discussions on forecast storage investment needs.

6 Exhibit (PG&E-4), Ch. 4.3, System Hardening, Enhanced Automation, and PSPS Impact Mitigations and Ch. 23, Community Rebuild Program.

- Use of forecast vintage retirements for specified common and general FERC accounts that is based on a predetermined schedule that reflects authorized service lives.⁷

Escalation where used will be fixed based on capital cost indices described in Exhibit (PG&E-12), Chapter 3.⁸ This proposal is responsive to intervenor concerns from prior General Rate Cases (GRC) that they do not have adequate resources to review a multi-year capital additions forecast. The forecast 2023 amounts in Table 3-2 below⁹ are included in workpaper (WP) Table 3-12. The forecast 2024, 2025, and 2026 amounts are included in WP Tables 3-13 to 3-15, respectively. The amounts on lines 2-5 can be found in the results of operations model. The amounts on lines 8-11 are escalated based on IHS Markit factors, which can be found on WP Table 3-10.

⁷ See Exhibits (PG&E-10), Ch. 10, Electric, Gas and Common Plant for discussion of vintage retirements. Exhibit (PG&E-11), WP Tables 3-16 to 3-18 shows the forecast vintage retirements for 2024, 2025 and 2026 based on recorded/forecast plant assets.

⁸ Exhibit (PG&E-11), WP Table 3-10 replicates the escalation rates for each year and each business, as well as common.

⁹ The forecast 2023 amounts in Table 3-2, lines 2-5, agree with Exhibit (PG&E-10), WP Table 10-45.

TABLE 3-2
PROPOSED CAPITAL ADDITIONS IN ATTRITION YEARS
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2023	2024	2025	2026
1	<u>Net Adds – Proposed Attrition Capital Additions^{(a),(b)}</u>				
2	Electric Distribution	\$4,257,875	\$4,914,613	\$5,555,095	\$5,822,351
3	Gas Distribution	1,404,842	1,241,835	1,355,156	1,309,832
4	EG	472,397	228,960	328,119	512,775
5	GT&S	1,046,324	1,002,517	988,732	952,157
6	Total (lines 2-5, and/or lines 12 and 19)	\$7,181,438	\$7,387,925	\$8,227,102	\$8,597,115
7	<u>Net Adds – IHS Markit Escalation^(b)</u>				
8	Electric Distribution (excl. CRESS and System Hardening)	\$2,434,154	\$2,455,381	\$2,654,070	\$2,559,367
9	Gas Distribution (excl. CRESS)	1,210,474	1,218,441	1,320,050	1,262,854
10	EG (excl. CRESS, Diablo Canyon and Hydro)	16,931	14,579	23,415	13,414
11	Gas Transmission (excl. CRESS and Storage)	809,275	819,537	870,301	856,608
12	Sub-total (lines 8-11)	\$4,470,835	\$4,507,938	\$4,867,836	\$4,692,243
13	<u>Net Adds – Detailed Forecast^(b)</u>				
14	Diablo Canyon	\$58,437	\$38,858	\$15,739	\$-
15	Hydro	193,994	151,087	264,249	482,285
16	CRESS (GRC ONLY)	857,926	103,258	143,002	175,363
17	Gas Storage	144,410	171,831	101,699	73,158
18	Electric Distribution – System Hardening ^(c)	1,455,836	2,414,954	2,834,578	3,174,067
19	Sub-total (lines 14-18)	\$2,710,603	\$2,879,987	\$3,359,266	\$3,904,872

- (a) Proposed Attrition Capital Additions equals the escalated TY net capital additions for all lines of business except for nuclear generation, Hydro, CRESS and gas storage where bottom-up forecast capital additions were used.
- (b) Net capital additions reflect forecast vintage retirements for certain common and general FERC accounts.
- (c) System hardening bottom-up forecast is a new category added as a result of PG&E's February 25, 2022 supplemental testimony.

1 PG&E has considered whether to use an escalated 7-year historical average
2 approach as one of its PTY mechanisms, however, estimating future capital
3 additions based solely on past spending ignores the fact that the capital
4 investment needed to provide safe and reliable service may change over time.
5 PG&E compared its forecast capital additions against the 7-year historical
6 approach¹⁰ and the 7-year approach does not provide PG&E with the funds
7 necessary to replace infrastructure and to respond to changing circumstances.
8 Specifically, for electric distribution, PG&E forecasts to invest \$11.1 billion in
9 capital expenditures during 2023 to 2026 to reduce the risk of catastrophic

¹⁰ Exhibit (PG&E-11), WP Table 3-9.

wildfires while also minimizing customer impacts caused by public safety power shutoffs (PSPS).¹¹ The resulting forecast PTY capital additions are significantly higher than what would be calculated using the 7-year historical approach. For gas distribution, PG&E forecasts capital expenditures that are higher than historical averages, due mainly to increased forecasts in several public safety programs, including main replacement.¹² Refer to Exhibit (PG&E-1), Chapter 1 for a summary of PG&E's proposed investments for years 2023 to 2026. Using historical spending to determine PTY investment may have been reasonable in some past TY periods (e.g. in PG&E's 2014 GRC), but in this GRC it would not adequately fund the spending required to provide safe and reliable service.

C. Other Rate Base PTY Adjustments for 2024 Through 2026

PG&E proposes the following PTY revenue adjustments:

1. Gas Storage

As described in Exhibit (PG&E-10), Chapter 11, PG&E is proposing to:

- fully amortize the net book value of Pleasant Creek to zero by December 2023, in compliance with PG&E's 2019 GT&S Decision (D.) 19-09-025; and
- refund customers the associated excess decommissioning and depreciation expense that PG&E recovered during years 2019 through 2022, in connection with its planned decommissioning of the Los Medanos storage field in 2023 because PG&E has decided to retain the Los Medanos storage facility for reasons described in Exhibit (PG&E-3), Chapter 7.

2. Gas Distribution Cost Recovery Proposal

As described in Exhibit (PG&E-10), Chapters 11 and 12, due to the expected decline in forecast gas throughput, PG&E has proposed the use of the units of production (UoP) methodology for the recovery of its gas distribution assets to mitigate cost increases and intergenerational inequity. PG&E also proposes phasing in the incremental annual \$186.1 million¹³ of

¹¹ Exhibit (PG&E-4), Electric Distribution, Ch.4.2.

¹² Exhibit (PG&E-3), Gas Operations, Ch.2.

¹³ Calculated based on 2023 WAVG plant balances.

1 depreciation expense using the UoP method instead of the straight-line
2 remaining life method. The incremental depreciation results are as follows:

- 3 • 2023 – 25 percent or approximately \$46.7 million;
- 4 • 2024 – 50 percent or approximately \$93.4 million;
- 5 • 2025 – 75 percent or approximately \$139.5 million; and
- 6 • 2026 – 100 percent or approximately \$186.1 million.

7 **3. Other DCCP Retirement Adjustments**

8 Due to the closure of DCCP at the end of 2025, attrition adjustments are
9 necessary for the following items:

- 10 • DCCP retirement decision approved the ratemaking of cancelled project
11 costs, which have been proposed to be recovered through the end of
12 2024;¹⁴
- 13 • DCCP's Utility Retained Generation regulatory asset amortization has
14 been proposed to be recovered through the end of 2024;¹⁵ and
- 15 • PG&E has proposed to recover its forecast of estimated material and
16 supplies inventory for DCCP that is necessary for the continued
17 operation of the plant through the end of 2025.¹⁶

**TABLE 3-3
OTHER RATE BASE PTY REVENUE ADJUSTMENTS
(MILLIONS OF NOMINAL DOLLARS)**

Line No.	Description	2023	2024	2025	2026
1	Gas Storage	\$(104)	–	–	–
2	Gas Distribution Cost Recovery Proposal	47	\$93	\$139	\$186
3	Other DCCP retirement adjustments	66	66	19	–
4	Total	\$9	\$159	\$158	\$186

18 **D. Separating Rate Base Into Unbundled Cost Categories**

19 Tables 3-4, 3-5, 3-6 and 3-7 summarize the proposed 2024, 2025, and 2026
20 attrition year rate base adjustments for electric distribution, gas distribution, EG,
21 and GT&S, respectively.

¹⁴ Exhibit (PG&E-10), Ch. 10, Section H.

¹⁵ Exhibit (PG&E-10), WP Tables 11-47 and 11-48.

¹⁶ Exhibit (PG&E-10), Ch. 15, Section C.2.

1 Net capital additions for 2024, 2025, and 2026 are developed for each
2 Unbundled Cost Category (UCC),¹⁷ based on the forecast 2023 net capital
3 additions plus escalation except for the use of bottom-up forecast in nuclear
4 generation, hydro, CRESS, gas storage and electric distribution – system
5 hardening, after incorporating forecast vintage retirements for certain common
6 and general FERC accounts, as described in Section B.

7 The 2023 forecast net additions, along with the other rate base elements
8 such as depreciation expense, reserve, and deferred taxes, are developed by
9 UCC. Once the forecast of plant net additions and the 2023 forecast of rate
10 base components are developed for each category, the 2024, 2025, and 2026
11 rate base components for electric and gas distribution, EG, and GT&S are
12 determined using the proposed attrition mechanism.

13 **E. Rate Base Growth and Related Costs**

14 Past Commission decisions have limited the rate base growth component of
15 the attrition mechanism to changes in plant, depreciation reserve, and
16 depreciation expense caused by capital additions and to changes in deferred
17 taxes associated with plant. Consistent with this practice, the Company is not
18 proposing to change the rate base elements of materials and supplies, customer
19 advances, or working cash for the attrition years of the rate case period. There
20 is, however, one exception in which there will be significantly less materials and
21 supplies for DCPD after Unit 1 and Unit 2 retirements in 2024 and 2025,
22 respectively.

23 The 2023 forecast plant additions data are included in Exhibit (PG&E-10),
24 Chapter 10. As proposed by PG&E, the 2024, 2025, and 2026 forecast net
25 capital additions are the escalated 2023 net capital additions, except for nuclear
26 generation, hydro, CRESS, gas storage and electric distribution - system
27 hardening, where the bottom-up forecast will be applied. The Weighted Average
28 (WAVG) net additions for 2024, 2025, and 2026 are calculated using the ratio of
29 the 2023 WAVG net additions over the 2023 end-of-year net additions, multiplied
30 by the 2024, 2025, and 2026 end-of-year net additions.¹⁸

¹⁷ See Exhibit (PG&E-10), Ch. 1, Tables 1-2 and 1-3, for list of electric and gas UCCs, respectively.

¹⁸ See line 3 of Tables 3-4 (electric distribution), 3-5 (gas distribution), 3-6 (electric generation) and 3-7 (GT&S), for these amounts.

1 The End-of-Year (EOY) plant balances for electric distribution for 2024,
2 2025, and 2026 are shown on line 4, of Table 3-4 in Columns C, F, and I,
3 respectively. The calculated WAVG plant increases for 2024, 2025, and 2026
4 are shown on line 4, in Columns E, H, and K, respectively.

5 The EOY plant balances for gas distribution for 2024, 2025, and 2026, are
6 shown on line 4 of Table 3-5 in Columns C, F, and I, respectively. The
7 calculated WAVG plant increases for 2024, 2025, and 2026 are shown on line 4
8 in Columns E, H, and K, respectively.

9 The EOY plant balances for EG for 2024, 2025, and 2026, are shown on
10 line 4 of Table 3-6 in Columns C, F, and I, respectively. The calculated
11 WAVG plant increases for 2024, 2025, and 2026 are shown on line 4 in
12 Columns E, H, and K, respectively.

13 The EOY plant balances for GT&S for 2024, 2025, and 2026 are shown on
14 line 4 of Table 3-7 in Columns C, F, and I, respectively. The calculated
15 WAVG plant increases for 2024, 2025, and 2026 are shown on line 4 in
16 Columns E, H, and K, respectively.

17 Consistent with the adopted approach in PG&E's 1993 and 1999 GRC
18 decisions, 2001 attrition decision, 2014, 2017 and 2020 GRC decisions,
19 depreciation expense (and other changes to depreciation reserve such as net
20 salvage, retirements, and accruals on motor vehicles) is calculated using the
21 ratio of the WAVG plant balance for the attrition year to the WAVG plant balance
22 for the previous year multiplied by the previous year's depreciation expense.¹⁹

23 The final attrition calculations will be based on the final adopted
24 capital-related amounts for 2023 rather than PG&E's forecasts. This includes
25 amounts for depreciation reserve and expense adopted in the 2023 GRC
26 decision rather than the forecasts for 2023 shown on Tables 3-4 through 3-7.
27 The final calculations will capture any changes in depreciation policy and rates
28 that are approved by the Commission. PG&E's 2023 depreciation expense and
29 WAVG reserve are discussed in Exhibit (PG&E-10), Chapter 11.

¹⁹ The depreciation expense amounts resulting from the levels of WAVG plant changes are shown on line 22 of Tables 3-4 (electric distribution), 3-5 (gas distribution), 3-6 (electric generation) and 3-7 (GT&S).

1 Income taxes are computed on rate base increases using the same net to
2 gross multiplier that is used for the TY. There are four tax adjustments made to
3 taxes in the attrition years.

4 First, PG&E reduces federal income tax expense, pursuant to D.89-11-058,
5 to reflect the increased federal income tax deductions that are available during
6 each attrition year for the prior year's California Franchise Taxes.

7 Second, PG&E reduces the level of deferred taxes (increases rate base) on
8 tax-normalized plant to reflect a reversal of deferred taxes that occurs primarily
9 because of bonus depreciation claimed in prior tax years. The reversal that
10 occurs in the TY will be used, as the reversal will be relatively stable over the
11 GRC cycle. Customers benefit from historical bonus depreciation through a
12 much higher starting level of deferred taxes (i.e., lower rate base), but that
13 benefit is reduced over time as book depreciation continues to be recorded and
14 the deferred taxes are repaid. The repayment of deferred taxes (increase to rate
15 base) occurs over this GRC cycle because the recovery of book depreciation is
16 included in PG&E's taxable income, while the remaining tax depreciation on
17 PG&E plant has been greatly diminished by successive past periods of bonus
18 depreciation. The deferred taxes have been offset with a net operating loss
19 (NOL) adjustment. The NOL offset is necessary to reflect the amount of
20 deferred taxes recorded in rate base that have not yet been realized by the
21 company through lower federal income tax payments.²⁰

22 Third, PG&E reflects the increasing "turn around" of tax expense due to
23 flow-through treatment of tax deductions including repairs. In the TY, PG&E will
24 reflect, as reduced tax expense, substantial upfront repair deductions for the
25 benefit of customers. When PG&E collects the capital costs associated with
26 these repair deductions in TY (through depreciation expense), there are no tax
27 deductions left afterwards and tax expense increases over TY levels. This
28 adjustment accounts for one vintage of reversals (TY additions eligible for
29 repairs) in the first attrition year, second vintage (first attrition year additions
30 eligible for repairs) in the second attrition year and similar computations for the
31 third attrition year.

²⁰ Exhibit (PG&E-10), Ch. 13, WP13-568.

1 Finally, PG&E has included an adjustment for the repairs deduction. The
2 repairs deduction is computed based on a certain percentage of qualifying
3 capital additions (repair factor) for each major work category (MWC) based on
4 historical trends. The annual repair deduction is computed by multiplying the
5 PTY MWC forecast additions times the MWC repair factor.

6 **F. Conclusion**

7 As demonstrated in this chapter and elsewhere in this exhibit, PG&E's
8 requests for 2024, 2025, and 2026 attrition year capital cost increases are
9 reasonable and appropriate. PG&E requests that the Commission adopt
10 PG&E's proposed methodology for reflecting attrition year capital costs, with the
11 simplifications discussed herein, including using TY plant additions with
12 escalation and adjustments described herein to compute attrition year additions.
13 PG&E also requests that the Commission compute updated rate base,
14 depreciation and property taxes for the attrition years to reflect these adopted
15 capital additions. Finally, PG&E requests that the other rate base PTY revenue
16 adjustments in Table 3-3 are adopted.

TABLE 3-4
ELECTRIC DISTRIBUTION
RATE BASE – ATTRITION
(MILLIONS OF NOMINAL DOLLARS)

Line No.	Description	2023			2024			2025			2026		
		Full Year (A)	WAVG Year (B)	Full Year (C)	WAVG Year (D)	WAVG Increase/Decrease (E)	Full Year (F)	WAVG Year (G)	WAVG Increase/Decrease (H)	Full Year (I)	WAVG Year (J)	WAVG Increase/Decrease (K)	
1	<u>Plant In Service</u>												
2	Beginning of Year	\$42,975	\$42,975	\$47,232	\$47,106	\$4,131	\$52,466	\$52,349	\$5,243	58,416	\$58,296	\$5,947	
3	Net Additions	4,258	2,226	4,915	2,583	357	5,555	2,919	337	5,822	3,060	140	
4	Total	\$47,232	\$45,201	\$52,147	\$49,689	\$4,488	\$58,021	\$55,268	\$5,579	\$64,238	\$61,356	\$6,087	
5	<u>Working Capital</u>												
6	Material & Supplies	\$344	\$344	\$344	\$344	–	\$344	\$344	–	\$344	\$344	–	
7	Working Cash	948	948	929	929	\$(19)	949	949	\$20	972	972	23	
8	Total	\$1,292	\$1,292	\$1,273	\$1,273	\$(19)	\$1,293	\$1,293	\$20	\$1,316	\$1,316	\$23	
9	<u>IRA Adjustments</u>												
10	Capitalized Interest	\$3	\$3	\$3	\$3	–	\$3	\$3	–	\$3	\$3	–	
11	Deferred Vacation	19	18	19	19	–	19	19	–	19	19	–	
12	CIAC Deferral	266	273	266	266	(7)	266	266	–	266	266	–	
13	Total	\$288	\$294	\$288	\$288	\$(6)	\$288	\$288	–	\$288	\$288	–	
14	<u>Customer Advances</u>	\$64	\$64	\$64	\$64	–	\$64	\$64	–	\$64	\$64	–	
15	<u>Deferred Taxes</u>												
16	Accum Def Taxes – Reg Asset	–	–	–	–	–	–	–	–	–	–	–	
17	Accum Def Taxes – Fixed Assets	\$1,543	\$1,739	\$1,541	\$1,542	\$(197)	\$1,624	\$1,583	\$41	\$1,713	\$1,669	\$86	
18	Accum Def ITC	21	21	21	21	(1)	21	21	–	21	21	–	
19	Total	\$1,563	\$1,760	\$1,561	\$1,562	\$(197)	\$1,645	\$1,603	\$41	\$1,734	\$1,689	\$86	
20	<u>Depreciation Reserve</u>												
21	Beginning of Year	\$18,620	\$18,620	\$19,958	\$19,953	\$1,333	\$21,420	\$21,475	\$1,522	\$23,306	\$23,393	\$1,918	
22	Depreciation Expense	2,089	1,045	2,288	1,144	99	2,538	1,269	125	2,802	1,401	132	
23	Net Salvage/Retirements/Other	(752)	(391)	(825)	(413)	(21)	(652)	(326)	86	(864)	(432)	(106)	
24	Total	\$19,958	\$19,273	\$21,420	\$20,684	\$1,411	\$23,306	\$22,418	\$1,733	25,244	\$24,362	\$1,944	
25	Rate Base Total	\$27,228	\$25,690	\$30,663	\$28,940	\$3,250	\$34,587	\$32,765	\$3,825	\$38,801	\$36,844	\$4,080	

TABLE 3-5
GAS DISTRIBUTION
RATE BASE – ATTRITION
(MILLIONS OF NOMINAL DOLLARS)

Line No.	Description	2023			2024			2025			2026		
		Full Year (A)	WAVG Year (B)	Full Year (C)	WAVG Year (D)	WAVG Increase/Decrease (E)	Full Year (F)	WAVG Year (G)	WAVG Increase/Decrease (H)	Full Year (I)	WAVG Year (J)	WAVG Increase/Decrease (K)	
1	<u>Plant In Service</u>												
2	Beginning of Year	\$17,075	\$17,075	\$18,480	\$18,430	\$1,355	19,890	\$19,839	\$1,408	\$21,454	\$21,405	\$1,566	
3	Net Additions	1,405	758	1,242	670	(88)	1,355	731	61	1,310	707	(24)	
4	Total	\$18,480	\$17,833	\$19,722	\$19,100	\$1,267	\$21,245	\$20,570	\$1,470	\$22,764	\$22,112	\$1,542	
5	<u>Working Capital</u>												
6	Material & Supplies	\$70	\$70	\$70	\$70	–	\$70	\$70	–	\$70	\$70	–	
7	Working Cash	234	234	233	233	–	244	244	10	256	256	12	
8	Total	\$304	\$304	\$304	\$304	–	\$314	\$314	\$10	\$326	\$326	\$12	
9	<u>IRA Adjustments</u>												
10	Capitalized Interest	\$2	\$2	\$2	\$2	–	\$2	\$2	–	\$2	\$2	–	
11	Deferred Vacation	10	10	10	10	–	10	10	–	10	10	–	
12	CIAC Deferral	77	79	77	77	(2)	77	77	–	77	77	–	
13	Total	\$89	\$91	\$89	\$89	\$(2)	\$89	\$89	–	\$89	\$89	–	
14	<u>Customer Advances</u>												
15	Deferred Taxes	\$12	\$12	\$12	\$12	–	\$12	\$12	–	\$12	\$12	–	
16	Accum Def Taxes – Reg Asset	–	–	–	–	–	–	–	–	–	–	–	
17	Accum Def Taxes – Fixed Assets	\$323	\$379	\$347	\$335	\$(44)	\$392	\$370	\$34	\$428	\$410	\$41	
18	Accum Def ITC	11	11	11	11	(0)	11	11	–	11	11	–	
19	Total	\$334	\$390	\$358	\$346	\$(44)	\$403	\$381	\$35	\$439	\$421	\$41	
20	<u>Depreciation Reserve</u>												
21	Beginning of Year	\$7,173	\$7,173	\$7,693	\$7,695	\$522	\$8,299	\$8,332	\$637	\$9,134	\$9,184	\$852	
22	Depreciation Expense	741	371	844	422	51	969	485	63	1,103	551	67	
23	Net Salvage/Retirements/Other	(221)	(115)	(238)	(119)	(3)	(134)	(67)	52	(233)	(117)	(50)	
24	Total	\$7,693	\$7,428	\$8,299	\$7,998	\$570	\$9,134	\$8,749	\$751	\$10,003	\$9,619	\$869	
25	Rate Base Total	\$10,834	\$10,398	11,445	\$11,137	\$739	12,099	\$11,831	\$694	\$12,724	\$12,474	\$643	

**TABLE 3-6
ELECTRIC GENERATION
RATE BASE – ATTRITION
(MILLIONS OF NOMINAL DOLLARS)**

Line No.	Description	2023			2024			2025			2026		
		Full Year (A)	WAVG Year (B)	Full Year (C)	WAVG Year (D)	WAVG Increase/Decrease (E)	Full Year (F)	WAVG Year (G)	WAVG Increase/Decrease (H)	Full Year (I)	WAVG Year (J)	WAVG Increase/Decrease (K)	
1	<u>Plant In Service</u>												
2	Beginning of Year	\$18,009	\$18,031	\$18,436	\$18,426	\$395	\$18,010	\$18,000	\$17,527	\$17,395	\$(605)		
3	Net Additions	472	255	229	114	(141)	328	150	513	223	73		
4	Total	\$18,481	\$18,287	\$18,665	\$18,540	\$253	\$18,338	\$18,150	\$18,040	\$17,617	\$(532)		
5	<u>Working Capital</u>												
6	Material & Supplies	\$84	\$84	\$64	\$64	\$(20)	\$43	\$43	\$33	\$33	\$(10)		
7	Working Cash	362	362	355	355	(7)	295	295	224	224	(70)		
8	Total	\$446	\$446	\$419	\$419	\$(27)	\$338	\$338	\$257	\$257	\$(80)		
9	<u>IRA Adjustments</u>												
10	Capitalized Interest	\$3	\$3	\$3	\$3	-	\$10	\$6	\$10	\$10	\$3		
11	Deferred Vacation	10	10	10	10	-	3	7	3	3	(4)		
12	CIAC Deferral	-	-	-	-	-	-	-	-	-	-		
13	Total	\$14	\$13	\$14	\$14	-	\$12	\$13	\$12	\$12	\$(1)		
14	<u>Customer Advances</u>												
15	Deferred Taxes												
16	Accum Def Taxes – Reg Asset	\$(6)	\$(6)	\$(6)	\$(6)	-	\$(6)	\$(6)	\$(6)	\$(6)	-		
17	Accum Def Taxes – Fixed Assets	342	424	311	326	(98)	356	334	427	392	58		
18	Accum Def ITC	75	78	75	75	(3)	74	74	74	74	-		
19	Total	\$410	\$495	\$380	\$395	\$(100)	\$424	\$402	\$496	\$460	\$59		
20	<u>Depreciation Reserve</u>												
21	Beginning of Year	\$12,286	\$12,286	\$12,821	\$12,832	\$546	\$13,375	\$13,278	\$13,725	\$13,610	\$333		
22	Depreciation Expense	768	384	782	391	7	718	359	402	201	(158)		
23	Net Salvage/Retirements/Other	(232)	(112)	(229)	(115)	(2)	(368)	(184)	(456)	(228)	(44)		
24	Total	\$12,821	\$12,557	\$13,375	\$13,108	\$551	\$13,725	\$13,453	\$13,671	\$13,584	\$131		
25	Rate Base Total	\$5,709	\$5,693	\$5,344	\$5,469	\$(224)	\$4,539	\$4,646	\$4,143	\$3,843	\$(603)		

**TABLE 3-7
GAS TRANSMISSION AND STORAGE
RATE BASE – ATTRITION
(MILLIONS OF NOMINAL DOLLARS)**

Line No.	Description	2023			2024			2025			2026		
		Full Year (A)	WAVG Year (B)	WAVG Increase/ (Decrease) (E)	Full Year (C)	WAVG Year (D)	WAVG Increase/ (Decrease) (E)	Full Year (F)	WAVG Year (G)	WAVG Increase/ (Decrease) (H)	Full Year (I)	WAVG Year (J)	WAVG Increase/ (Decrease) (K)
1	<u>Plant In Service</u>												
2	Beginning of Year	\$10,431	\$10,431	\$1,084	\$11,477	\$11,514	\$1,084	\$12,560	\$12,601	\$1,087	\$13,648	\$13,688	
3	Net Additions	1,046	481	(20)	1,003	461		989	454	(6)	952	438	
4	Total	\$11,477	\$10,912	\$1,063	\$12,480	\$11,975	\$1,063	\$13,548	\$13,055	\$1,080	\$14,600	\$14,125	
5	<u>Working Capital</u>												
6	Material & Supplies	\$58	\$58	-	\$58	\$58	-	\$58	\$58	-	\$58	\$58	
7	Working Cash	138	138	-	138	138	-	143	143	5	149	149	
8	Total	\$196	\$196	-	\$196	\$196	-	\$201	\$201	\$5	\$206	\$206	
9	<u>IRA Adjustments</u>												
10	Capitalized Interest	\$7	\$6	\$1	\$7	\$7	\$1	\$7	\$7	-	\$7	\$7	
11	Deferred Vacation	5	5	-	5	5	-	5	5	-	5	5	
12	CIAC Deferral	-	-	-	-	-	-	-	-	-	-	-	
13	Total	\$12	\$11	\$1	\$12	\$12	\$1	\$12	\$12	-	\$12	\$12	
14	<u>Customer Advances</u>												
15	Deferred Taxes	\$19	\$19	-	\$19	\$19	-	\$19	\$19	-	\$19	\$19	
16	Accum Def Taxes – Reg Asset	-	-	-	-	-	-	-	-	-	-	-	
17	Accum Def Taxes – Fixed Assets	\$627	\$644	\$35	\$731	\$679	\$35	\$876	\$803	\$124	\$1,028	\$952	
18	Accum Def ITC	5	5	-	5	5	-	5	5	-	5	5	
19	Total	\$631	\$648	\$35	\$736	\$684	\$35	\$880	\$808	\$124	\$1,033	\$957	
20	<u>Depreciation Reserve</u>												
21	Beginning of Year	\$2,993	\$2,993	\$100	\$3,087	\$3,093	\$100	\$3,282	\$3,303	\$210	\$3,590	\$3,619	
22	Depreciation Expense	239	119	66	371	185	66	408	204	19	444	222	
23	Net Salvage/Retirements/Other	(144)	(59)	(29)	(175)	(88)	(29)	(100)	(50)	38	(142)	(71)	
24	Total	\$3,087	\$3,053	\$137	\$3,282	\$3,190	\$137	\$3,590	\$3,457	\$266	\$3,893	\$3,770	
25	Rate Base Total	\$7,947	\$7,398	\$892	\$8,650	\$8,290	\$892	\$9,271	\$8,984	\$694	\$9,874	\$9,598	

**PACIFIC GAS AND ELECTRIC COMPANY
2023 GENERAL RATE CASE**

Testimony X Workpapers _____ SOQ _____

Exhibit Number: 11 Chapter Number: 3

Chapter Title: **Rate Base Growth in Attrition Years and Related Costs**

Witness Name: **Pei Sue Ong**

Page No.	Line No.	Item	As Filed	As Corrected
Errata as of November 5, 2021				
Testimony p.3-15 Table 3-7	14	Line 14 Customer Advances has missing data; No change in the total Rate Base (Line 25)	All Zero	Table 3-7 Line 14 Full Year and WAVG Year Rate Base (Column A,B, C, D, F, G, I, J) should be \$19 million instead.
Testimony p. 3-10	Footnote #19	Reference to Tax WP should be changed	WP 13-319	WP 13-568