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Date: October 29, 2025
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

REVISIONS AND ERRATA TO JULY 18, 2025 PREPARED TESTIMONY

EXHIBIT (PG&E-3)

REVENUE ALLOCATION AND RATE DESIGN

(CLEAN VERSION)

PACIFIC GAS AND ELECTRIC COMPANY
2023 GENERAL RATE CASE PHASE II
EXHIBIT (PG&E-3)
REVENUE ALLOCATION AND RATE DESIGN
ERRATA TESTIMONY

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A. Introduction

Pacific Gas and Electric Company's (PG&E) 2023 General Rate Case Phase II (GRC II) is the opportunity for the California Public Utilities Commission (CPUC or Commission) to update electric marginal costs and revise the associated revenue allocation and rate design[1] for each customer class.[2] The Commission's decision in this proceeding will set marginal cost, revenue allocation, and rate design policies, including the rate design that will ultimately be applied to PG&E's authorized revenue requirements, which are determined in other proceedings.

GRC II proceedings generally include three steps: (1) determining marginal costs via cost-of-service studies; (2) allocating generation and distribution revenue requirements to customer classes; and (3) designing generation and distribution rates to collect these allocated revenue requirements while reflecting marginal costs of service. PG&E's marginal cost of service studies are presented in Exhibit (PG&E-2) and are used to support the revenue allocation and rate design proposals presented in this exhibit.

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1 ALJ Atamturk issued a Ruling on October 9, 2025 bifurcating the Real-Time Pricing (RTP) rate design and implementation issues into a separate new track of PG&E's 2023 GRC Phase II. The Errata Testimony referenced here consists of Exhibits 1 – 4 also referred to as the Primary Track (Track A) of this GRC Phase II. The ALJ's Ruling established a schedule for Track A (on all non-RTP issues). The Ruling required PG&E to file a Motion by November 17, 2025 proposing a schedule for the bifurcated RTP Track (Track B). The new Supplemental RTP Testimony to be considered in Track B is presented in Exhibit 5 here, per the 60-day filing deadline established in CPUC Decision (D.) 25-08-049, issued on August 28, 2025. The Supplemental RTP Testimony *supersedes* the previous Chapter 10 (RTP) from PG&E's original testimony supporting our September 30, 2024 GRC Phase II Application (A.) 24-09-014. The new Supplemental RTP Testimony will be considered on whatever schedule is adopted, later in 2025, after the CPUC has reviewed the Motion (required to be filed by November 17, 2025) as well as any timely responses to that Motion.

2 Customer classes include: Residential, Small Light and Power (SL&P), Medium Light and Power (ML&P), Large Light and Power (LL&P), Industrial, Standby, Agriculture, Streetlights, and Business Electric Vehicles (BEV).

Revenue allocation is the step in the rate design process through which individual revenue requirement functions (e.g., distribution or generation) are assigned (or allocated) to each customer class. Revenue allocation results provide the target levels of revenue based on fully-allocated cost of service. PG&E's proposal for revenue allocation adjusts revenue for each customer class to better reflect fully allocated cost of service.

After revenue requirements have been allocated to customer classes, the next step in the rate design process is to derive the prices, or rates, which will apply to each rate schedule component to collect the allocated revenue on a forecast basis. PG&E proposes to retain the same time-of-use (TOU) period definitions in this 2023 GRC II application that were previously authorized by the Commission. The rate design changes PG&E proposes here seek to adjust rates across all customer classes to move them closer to their marginal cost basis. For example, PG&E proposes adjustments to non-residential customer charge levels and TOU period rate differentials, while also being mindful of providing customers with some measure of rate stability.

All of PG&E's proposals in this exhibit are based on July 1, 2024 rate levels and Commission-adopted 2024 test year sales forecasts.[3] Present rates used in this exhibit for comparison with the proposed rate levels have been recalculated, where practicable, so that the comparison to proposed rates will reflect only PG&E's proposals in this proceeding. For instance, in PG&E's 2020 GRC II decision, the CPUC adopted a 3-step change to E-TOU-C peak to off-peak rate differentials. While Step 3 will not be implemented until June of 2025, PG&E has reflected these changes in present rates since it will be in effect *prior* to the conclusion of this proceeding. PG&E has made these adjustments so that the rate changes reflected in proposed rates and bill comparisons are based *solely* on PG&E's rate proposals requested in this proceeding. Details on each adjustment can be found in the applicable rate design chapter.

The remainder of this chapter is organized as follows:

- Section B – Rate Design Objectives;

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[3] July 1, 2024 present rates were implemented through Advice 7307-E. 2024 test-year sales forecast was adopted by D.23-12-022 in PG&E's 2024 Energy Resource Recovery Account Forecast proceeding.

- Section C – Summary of Key Proposals;
- Section D – Revenue Allocation;
- Section E – Rate Design;
- Section F – Organization of This Exhibit; and
- Section G – Conclusion.

B. Rate Design Objectives

PG&E's rate design objectives in this proceeding are guided by the Commission's adopted Rate Design Principles (RDP). The Commission recently adopted a refreshed set of RDPs in D.23-04-040, which affirmed and updated previously-established RDPs. Table 1-1, below, presents the ten RDPs.

TABLE 1-1
CURRENT CPUC-ADOPTED RDPs (D.23-04-040)

Principle	Description
Principle 1	All residential customers (including low-income customers and those who receive a medical baseline or discount) should have access to enough electricity to ensure that their essential needs are met at an affordable cost.
Principle 2	Rates should be based on marginal cost.
Principle 3	Rates should be based on cost-causation principles.
Principle 4	Rates should encourage economically-efficient: (1) use of energy, (2) reduction of greenhouse gas emissions, and (3) electrification.
Principle 5	Rates should encourage customer behaviors that improve electric system reliability in an economically-efficient manner.
Principle 6	Rates should encourage customer behaviors that optimize the use of existing grid infrastructure to reduce long-term electric system costs.
Principle 7	Customers should be able to understand their rates and rate incentives and should have options to manage their bills.
Principle 8	Rates should avoid cross-subsidies that do not transparently and appropriately support explicit state policy goals.
Principle 9	Rate design should not be technology-specific and should avoid creating unintended cost-shifts.
Principle 10	Transitions to new rate structures should: (i) include customer education and outreach that enhances customer understanding and acceptance of new rates, and (ii) minimize or appropriately consider the bill impacts associated with such transitions.

Most notably, in this proceeding, PG&E seeks to make progress toward rates that are more cost-based, more economically-efficient, promote greater equity among customers, and encourage customer behaviors to reduce long-term electric system costs. However, efforts to meet these goals must invariably balance multiple competing objectives including: compliance with statutes and CPUC rules, rate stability, understandability, customer acceptance, and advancing state policy objectives, such as transportation electrification and building decarbonization. Among others, PG&E's revenue allocation and rate design proposals are guided by the following objectives:

1. Cost of Service

Public Utilities Code (Pub. Util. Code) Section 451 requires that the Commission establish rates that are "just and reasonable."[4] Traditionally, "just and reasonable" rates are based on the cost of service.[5] The costs of providing utility services vary with customer usage characteristics and with the facilities needed to serve a customer. The Commission has a long history of using the Equal Percent of Marginal Cost (EPMC) method to establish a cost-based allocation of revenue among customer classes.[6]

The Commission has consistently held that utilities' underlying marginal costs should be the basis for revenue allocation and rate design so that customers receive clear and appropriate cost-based price signals associated with their electric usage decisions.[7] Doing so encourages more efficient use of energy and the PG&E delivery system. Further, appropriate price signals help mitigate uneconomic decision-making by customers. As the CPUC noted in its decision in PG&E's 2017 GRC II:

> The advantages of the EPMC approach are its simplicity, transparency and fairness. The equation…is simple and transparent, but *it relies on an accurate assignment of marginal costs to each class*. It is fair because it assigns the non-marginal costs to each class proportionate to

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4 Pub. Util. Code, Section 451.

5 See James Bonbright, et al., Principles of Public Utility Rates, specifically, Chapter 5, Cost of Service as a Basic Standard of Reasonableness.

6 See Exhibit (PG&E-2), Chapter 1 for background regarding the use of marginal cost for cost of service.

7 Many of the Commission adopted rate design principles support cost-based rate design, including RDP 2, 3, 4, 6, 7, and 9. See D.23-04-040, p. 2.

their marginal cost responsibility, which means that those classes that impose the greatest additional (or new) costs on the utility also bear the greatest burden for the existing utility costs. This creates an incentive for every class to avoid imposing additional (or new) costs on the utility, which in theory keeps rates for all classes as low as possible.[8]

PG&E supports applying the EPMC method for revenue allocation. However, for rate design, PG&E generally prefers sending TOU price signals based on the nominal marginal energy or capacity costs so that customers are not over-incentivized to shift their loads. In other words, the benefit customers receive from load shifting should be commensurate with the reduction in PG&E's costs. Unless supported by clear policy objectives, over-incentivizing load-shifting behavior would result in PG&E recovering less revenue than it avoids in costs, thus creating a subsidy paid by remaining customers.

Exhibit (PG&E-3) presents PG&E's proposals for revenue allocation and rate design that take meaningful steps towards the marginal cost basis, as outlined in the following high-level summary, by chapter:

1) In Chapter 2, on Revenue Allocation, PG&E proposes to allocate revenues on a full-cost basis using the EPMC method, by moving one-quarter of the way to full-cost each year, for four years. For customer classes that exceed a bundled rate increase of 8 percent, PG&E proposes to move one-fourth of the way towards an 8 percent cap per year;
2) In Chapters 3, 4, 5, and 7 on Rate Design for PG&E's Residential, Commercial and Industrial (C&I), Agricultural, and BEV rate schedules, PG&E's proposals include rate adjustments to the rate differentials among TOU periods based on time-differentiated marginal costs;
3) Similarly, in Chapters 4 and 5, on C&I and Agricultural Rate Design, PG&E proposes an increase to most non-residential customer charges

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8 See D.18-08-013, pp. 14-15 (citation omitted, emphasis added). That decision also noted that D.96-04-050 had established EPMC as the Commission's preferred starting point for cost-based rate design and was one of the final Commission decisions to fully litigate marginal costs, revenue allocation, and rate design issues for a major electric utility: "Our adoption of settlements is not precedential. Therefore, the findings and conclusions of D.96-04-050 remain valid and should be regarded as the starting point for the Commission's evaluation of whether revenue allocation and rate designs are reasonable." (citation omitted) D.18-08-013, p. 19.

to recover a greater share of the customer-related distribution marginal costs and other non-marginal costs.

2. Rate Stability

While it is important to move toward more appropriate, economically-efficient, and cost-based price signals, this goal should be balanced with the awareness of mitigating changes that might otherwise result in sudden and unduly large bill increases, for a measure of rate stability. Historically, mitigation of the impact of rate changes has included a combination of moderating both the changes made in revenue allocation, as well as in rate design. For example, in PG&E's 2020 GRC II, PG&E proposed to minimize changes in rate designs, since most residential customers were being transitioned to default TOU rates for the first time, and many non-residential customers were still in the process of transitioning to new rate schedules with later TOU peak periods.

The TOU transitions customers were facing over the course of PG&E's 2020 GRC II period are now complete for the majority of customers. Specifically, the transition of eligible residential customers to Schedule E-TOU-C was completed in May 2022, and the transition of most non-residential customers to rate schedules with later TOU peak periods was completed in March 2021. Finally, many of the revenue allocation and rate design changes adopted in PG&E's 2020 GRC II proceeding were implemented in June 2022.[9]

PG&E expects a final decision in this GRC II proceeding no earlier than mid-2026. By that time, customers will have had multiple years to acclimate to the new TOU periods. Accordingly, in this 2023 GRC II proceeding, PG&E proposes meaningful adjustments to move both revenue allocation and rate levels towards full-cost, while being mindful of rate stability, as follows:

1) While PG&E proposes to move to full-cost revenue allocation for all classes, up to an 8 percent bundled rate impact as supported in Chapter 2 of Exhibit (PG&E-3), this change is balanced over a 4-year period so that all classes will not experience an increase of more than 1.9 percent

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9 See Advice Letters (AL) 6603-E and 6566-E, implementing D.21-11-016.

per year and most classes will see increases of much less than 1.9 percent per year.[10]

2) PG&E generally proposes to maintain the current rate structures, including TOU period definitions, charge types, and eligibility thresholds. Doing so builds upon existing customer knowledge and education so PG&E's rate design proposals can focus on sending more cost-based price signals.

3) In many cases, PG&E's rate design proposals only propose to move part-way to cost based rate levels, as justified by the marginal cost analysis, to avoid significant customer bill impacts.

3. Understandable, Meaningful, and Practical to Implement

In general, rate design proposals should seek to balance the increasing complexity of rates, with the need to provide rates that are understandable and empower customers to take actions to reduce their energy expenses. Rates should also be as transparent as possible. This means unbundled rates (that is, rates unbundled by component such as distribution, Public Purpose Programs (PPP) and generation) should recover costs that are correctly captured within each unbundled component. For example, distribution and generation rates should not be used to recover costs that are associated with providing a public benefit program and might be more appropriately identified as Public Purpose.

Finally, rates must be practical for PG&E to implement. Rate structures should not be overly complex as to hinder customer understanding and increase implementation costs. As described in Exhibit (PG&E-3), Chapter 10, PG&E's billing system is undergoing a modernization effort which is expected to be completed in 2029 at the earliest. Due to these changes, and the significant number of rate projects already under development, PG&E's proposals in this proceeding are limited to rate value changes (not structural changes to the billing system),[11] which PG&E can

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[10] As described further in Chapter 2 of Exhibit (PG&E-3), the three classes that would receive larger impacts are the BEV, Agriculture, and Standby customer classes.

[11] For further details and definitions, please see Chapter 10 of this exhibit.

reasonably implement on a timely basis following the final decision issued in this proceeding.

4. Optimized Portfolio of Rate Schedules and Rate-Related Programs

PG&E's portfolio of rate schedules and rate-related programs for each customer class should be developed and then evolve to support California's affordability, reliability, and policy goals in the long-term. PG&E's rate portfolio has grown over the past several GRCs with some options being adopted without full consideration of the fit within the portfolio and the long-term objectives. Indeed, in a recent CalFUSE whitepaper, the CPUC staff has recognized that:

> [T]he retail electric rates ecosystem has experienced a proliferation of specialized rate structures to support disparate policy goals….[12]

It is important that customers can easily understand the different rate options presented to them and select the combination of options that best suits their needs. Each rate schedule within the overall rate portfolio should be clearly differentiated and offer unique value. This portfolio should be re-evaluated regularly and rate schedules or rate programs should be carefully considered for modification or elimination if they have low customer interest, offer value propositions that are duplicative of other existing offerings, or are misaligned with state energy policy objectives or the Commission adopted RDPs. Similarly, a careful evaluation should occur prior to introducing new rate options that consider factors such as: (1) the expected level of enrollment and coherence with customer preferences, (2) cost-effectiveness, (3) implementation cost and complexity, and (4) alignment with California's energy policy goals and the Commission's RDPs. PG&E's proposals in this proceeding seek to adjust certain existing rate schedules to offer more clear and meaningful differentiation between the rate options available to customers.

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[12] CPUC, Energy Division White Paper and Staff Proposal, Advanced Strategies for Demand Flexibility Management and Customer DER Compensation (June 22, 2022), p. 27.

C. Summary of Key Proposals

PG&E's key revenue allocation and rate design proposals other than the RTP track are summarized by chapter in Table 1-2, below.

TABLE 1-2
SUMMARY OF KEY REVENUE ALLOCATION AND RATE DESIGN PROPOSALS

Chapter in Exhibit (PG&E 3)	Topic	Sponsoring Witnesses	Overview of Key Proposals
2	Revenue Allocation	T. Streib	Move to full-cost revenue allocation gradually by moving one-quarter of the way to full cost each year, for four years. For customer classes that exceed a bundled rate increase of 8 percent, move one-fourth of the way towards an 8 percent cap each year, for four years.
3	Residential	C. Kerrigan S. Jin A. Taylor H. Krogh-Freeman J. Au N. Yang	For rate schedules with TOU periods, adjust TOU rate differentials to move towards marginal cost differentials. Update residential baseline quantities. For Schedules E-1 and E-TOU-C, reduce differentials between Tier 1 and Tier 2 rates and maintain tier relationship on a cents per kilowatt-hour (kWh) basis. Adjust PG&E's residential master meter discount and diversity benefit adjustment. Eliminate the SmartRate™ minimum event days requirement. Eliminate the minimum bill revisions in light of the Residential Fixed Charge implementation plan.
4	Commercial and Industrial	T. Yu	Adjust TOU rate differentials to move towards marginal cost differentials. Adjust customer charges to move towards EPMC-scaled Marginal Customer Costs (MCC). Apply 75 kilowatt (kW) eligibility threshold to previously exempt customers on Schedules A-6 and B-6 by 2028.
5	Agriculture	S. Jin	Adjust TOU rate differentials to move towards marginal cost differentials. Adjust customer charges to move towards EPMC-scaled MCCs. Update Schedule AG-C Demand Charge Rate Limiter (DCRL) and associated rate adder.
6	Streetlights	P. Pra	Adjust facility charges one-fourth the way towards full-cost over a 4-year period, up to an 8 percent cap. Increase Schedule LS-3 partially towards EPMC-scaled MCCs.

TABLE 1-2
SUMMARY OF KEY REVENUE ALLOCATION AND RATE DESIGN PROPOSALS (CONTINUED)

Chapter in Exhibit (PG&E 3)	Topic	Sponsoring Witnesses	Overview of Key Proposals
7	BEVs	T. Streib O. Tiell	Adjust TOU energy rate differentials to move partially towards marginal cost differentials. Adjust Schedule BEV-2 subscription rate in proportion to marginal costs that are customer related or non-coincident.
8	Economic Development Rate (EDR)	D. Gutierrez	Maintain existing EDR discount amounts. Increase EDR total enrollment cap to 200 megawatts.
9	Rate Program Fees for Services to Energy Service Providers (ESP)	T. Wong	Escalate fees for three services provided to Energy Service Providers (ESP) under Direct Access (DA) and Community Choice Aggregator (CCA) programs. Request for future escalation proposals to be requested through a Tier 2 advice letter, rather than rate design proceeding.
10	Implementation and Marketing, Education, and Outreach (ME&O)	E. Bartman J. Chesler	Discuss constraints on implementing structural billing changes needed to implement new rates and changes to existing rate structures due to PG&E's Billing Modernization Initiative. Conduct ME&O for customers impacted by proposed changes in rate schedule eligibility. Conduct ME&O for customers adversely impacted by final rate design changes adopted by a final decision.

D. Revenue Allocation

In this proceeding, PG&E is proposing changes in revenue allocation for generation, distribution, and PPP. In addition, the proposed changes to rates affect both the residential Conservation Incentive Adjustment (CIA) rate component and the California Alternate Rates for Energy surcharge, which is a component of the PPP rate.[13] PG&E's proposals for revenue allocation are described in detail in Chapter 2 of this exhibit.

PG&E's objective for revenue allocation in this proceeding is to bring each customer classes' revenue responsibility closer to its cost of service. As described further in Chapter 2 of this exhibit, revenue allocation has remained far away from full-cost levels for the past several decades largely due to a string of non-precedential settlements that spanned over 20 years, leading to a lack of Commission-approved marginal costs. As noted previously, in this proceeding PG&E proposes to move to full-cost revenue allocation gradually by moving one-quarter of the way to full cost each year, for four years, up to an 8 percent bundled rate impact.

E. Rate Design

After revenue requirements have been allocated to customer classes, the next step in the rate design process is to derive the prices, or rates, which will apply to each rate schedule to collect the allocated revenue on a forecast basis. PG&E's rate design proposals have been constructed to take meaningful steps towards the marginal cost basis, while balancing other objectives such as rate stability and understandability.

Rates for distribution and generation can be collected via some combination of a monthly basis (per customer), a volumetric basis (per kWh), or a demand basis (per kW). In addition, both generation and distribution charges may be time-differentiated. PG&E supports using marginal cost differentials to design TOU rates so that customers are not over-incentivized to shift their loads. In other words, the benefit customers receive from doing so should be commensurate with the reduction in PG&E's costs that results from the load shifting. Unless supported by a clear policy objective, over-incentivizing load shifting behavior would result in PG&E losing more revenue than it avoids in

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[13] Total rates consist of a number of different functions including: Transmission, Distribution, Generation, Public Purpose Programs, Nuclear Decommissioning, Wildfire Fund Charge, New System Generation Charge, the Energy Cost Recovery Amount, Competition Transition Charge, Power Charge Indifference Adjustment, Wildfire Hardening Charge, Recovery Bond Charge, and Recovery Bond Credit. In addition, DA and CCA customers pay the Power Charge Indifference Adjustment and the Franchise Fee Surcharge. Transmission charges are regulated by the Federal Energy Regulatory Commission and are not subject to change in this proceeding. PG&E's proposals for change in this proceeding are limited to rates for PPP, generation and distribution.

costs, thus creating a subsidy that must be paid by all customers in the form of higher rates to make up the shortfall.

Finally, PG&E is generally proposing rate design changes for all existing rate schedules *except* for legacy non-residential rate schedules.[14] Legacy non-residential rate schedules are set to be retired for eligible public agencies by December 31, 2027 and for all other eligible non-residential customers by July 31, 2027. It would be costly and potentially confusing to customers for rate design changes to become effective following a final decision in this proceeding (which is anticipated to be no earlier than mid-2026), only to have those rate schedules retired shortly thereafter.[15] While PG&E does not propose any rate design changes for these legacy rate schedules, PG&E's proposed revenue allocation changes will impact the total rate levels for these rate schedules.

1. Customer Charges

a. Residential Customer Charge

Until recently, PG&E collected revenues from its residential customers almost exclusively on a volumetric basis.[16] In PG&E's 2020 GRC II proceeding, PG&E introduced its first optional residential rate schedule with a fixed customer charge (fixed charge), Schedule E-ELEC.[17] Collecting a portion of distribution customer marginal costs in a fixed charge lowers the volumetric energy charges, providing a more cost-based price signal to customers seeking to electrify their household appliances.

Subsequently, on May 15, 2024, the CPUC issued D.24-05-028 authorizing all investor-owned electric utilities to change the structure of residential customer rates in accordance with Assembly Bill (AB) 205, Stats. 2022, Ch. 61 (AB 205). This decision approved a new fixed

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[14] Legacy non-residential rate schedules include Schedules A-1, A-1 TOU, A-6, A-10, E-19, E-20, AG-1, AG-4, AG-5, AG-R, AG-V, and S.

[15] The timeline for closure of the legacy non-residential rate schedules was approved by D.17-01-006.

[16] With the exception of minimum bill amounts, which apply only to a small percentage of very low-usage customers.

[17] Schedule E-ELEC is also known as the "Electric Home" rate plan. The tariff refers to the fixed charge as a "base services charge."

charge, which alters the structure of all residential rate schedules by shifting the recovery of a portion of fixed costs from volumetric rates to a separate, fixed amount (that varies by customer income category) on bills without changing the total costs that utilities may recover from customers. As required by D.24-05-028,[18] PG&E submitted a Tier 3 Advice Letter (AL) 7351-E on August 13, 2024 clarifying its proposals for how to implement the final decision's adopted initial Fixed Charge in the first quarter of 2026.

In this proceeding, PG&E has modeled a set of illustrative proposed rates for its residential rate schedules including the anticipated fixed charge based on PG&E's proposal in AL 7351-E. Consistent with PG&E's proposal, the fixed charge recovers a portion of distribution, Nuclear Decommissioning, PPP, and New System Generation Charge revenues, with remaining revenues being recovered through volumetric energy charges.

b. Non-Residential Customer Charges

Non-residential rate schedules have a long-standing history of utilizing customer charges to recover all or a portion of the customer-related distribution marginal costs. PG&E generally advocates that customer charges should be determined based on their fully-scaled cost-based levels. These levels are derived by scaling up class-specific MCCs by the EPMC multiplier associated with PG&E's distribution revenue.[19] For the last several years, to promote rate stability in light of other rate-related changes that have occurred, PG&E has not updated customer charges applicable to SL&P and Agricultural rate schedules to reflect recent marginal costs.

In this proceeding, PG&E proposes to take a meaningful step to adjust all non-residential customer charges towards their fully-scaled MCC levels, while mitigating changes for certain rate schedules by considering the magnitude of customer bill impacts. Table 1-3, below,

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18 D.24-05-023, pp. 3-4.

19 MCCs include Revenue Cycle Services, Marginal Customer Equipment Costs, and Marginal Line Extension Costs.

provides a comparison of current monthly customer charges, full cost-based customer charges, and the proposed customer charges in this proceeding.

TABLE 1-3
PRESENT AND PROPOSED NON-RESIDENTIAL CUSTOMER CHARGES

Line No.	Customer Class	Ch.	Sponsoring Witness	Rate Schedule(s)	Current	Proposed	Full Cost[a]
1	SL&P	4	T. Yu	B-1, B1-STORE, B-6, A-15 (single phase)	$10	$50	$89
2				B-1, B1-STORE, B-6 (polyphase)	$25	$100	$285
3				TC-1	$15	$25	$51
4	ML&P			B-10 (incl. Option R)	$327	$600	$870
5	LL&P			B-19T (incl. Options R/S)	$3,664	$5,080	$5,080
6				B-19P (incl. Options R/S)	$2,508	$2,692	$2,692
7				B-19S (incl. Options R/S)	$1,663	$2,154	$2,154
8	Industrial			B-20T (incl. Options R/S)	$11,596	$11,596	$59,885
9				B-20P (incl. Options R/S)	$3,220	$2,899	$2,899
10				B-20S (incl. Options R/S)	$3,109	$4,561	$4,561
11	Agriculture	5	Sarah Jin	AG-A1, AG-A2, AG-A3, AG-FA	$21	$31	$117
12				AG-B1, AG-B2	$28	$65	$357
13				AG-C	$44	$160	$562
14	Streetlights	6	P. Pra	LS-3	$8	$11	$20

(a) Full Cost represents EPMC-scaled MCCs without changes to revenue allocation.

As a result of PG&E's proposals, customer charges will increase for most rate schedules, in particular. These changes will result in decreases to energy charges and demand charges, as applicable, which will result in more cost-based rates.[20] These adjustments are aligned with CPUC RDPs. First, these adjustments will make the rate design for non-residential rate schedules more cost-based by collecting customer-related marginal costs, which do not vary based on usage or

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[20] Demand charges are not applied to SL&P rate schedules.

demand, through fixed monthly customer charges.[21] Second, lower energy and demand charges will encourage economically-efficient building and transportation electrification by lowering the incremental cost for customers to add additional load to the system.[22] Finally, PG&E's proposed adjustments to non-residential customer charges have been developed with customer rate stability in mind. PG&E recommends only partial movements towards full cost-based rates for many rate schedules to mitigate large bill impacts. In addition, Chapter 10 presents PG&E's ME&O plan which includes a proposal to assess bill impacts based on the rate design adopted by a final decision in this proceeding and communicate with the most impacted customers prior to implementation.[23]

2. Distribution Demand and Energy Charges

In general, distribution revenue that is not collected in the customer charge is collected in demand and energy charges. Ideally, the time differentiation in distribution rates would be accomplished through a peak period distribution demand charge since customer demands are the primary drivers of distribution capacity costs, or alternatively, through time-differentiated energy rates. All remaining revenue would then be assigned to a non-coincident demand charge or non-time-differentiated energy rates. However, due to varying levels of customer sophistication across PG&E's customer classes, PG&E maintains certain rate schedules that deviate from this approach.

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21 See D.23-04-040, pp. 10 and 12, CPUC Rate Design Principle 2: "rates should be based on marginal cost," and Rate Design Principle 3, "rates should be based on cost-causation principles."

22 See D.23-04-040, p. 15, CPUC Rate Design Principle 4: "rates should encourage economically efficient (i) use of energy, (ii) reduction of GHG emissions, and (iii) electrification."

23 See D,23-04-040, p. 22, CPUC Rate Design Principle 10: "transitions to new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates and minimizes and appropriately considers the bill impacts associated with such transitions."

3. Generation Demand and Energy Charges

PG&E recommends that generation revenue should be collected in peak-related demand and energy charges. PG&E recommends marginal energy costs be used to time-differentiate energy rates. Similarly, PG&E recommends that generation capacity costs be used to time-differentiate generation rates through either a peak period generation demand charge or, alternatively, through time-differentiated energy rates. All remaining revenue would then be assigned to collection through energy rates.

4. Illustrative Rate and Bill Calculations

As noted above, in this proceeding, PG&E is only proposing changes to rates for distribution, generation, and PPP. Rates for all other functional revenue requirement components remain unchanged in the illustrative rates presented in this proceeding. In general, rates for each functional revenue requirement component are added together to determine the total bundled rate. However, total residential rates that include rate tiers are determined differently. For those rate schedules, total bundled tiered rates generally are first designed to collect the total revenue, and then rates are unbundled to each functional revenue requirement component and the CIA is set residually. Residential rate design proposals are set forth in Chapter 3 of this exhibit.

PG&E has developed two sets of illustrative rates in this proceeding, as presented in Appendix C of Exhibit (PG&E-4). The first set of illustrative rates applies the full set of rate design changes proposed by PG&E while continuing to reflect present rate revenues. In other words, this first set of illustrative rates does not reflect the revenue allocation changes proposed by PG&E. This set of illustrative rates is used to calculate the bill impacts presented in Appendix D of Exhibit (PG&E-4). This approach allows for a more refined understanding of how PG&E's rate design proposals, which are designed to maintain revenues on a forecast basis, impact various segments of customers. The second set of illustrative rates applies both the proposed revenue allocation and rate design changes. This set of rates takes the first set of illustrative rates and applies PG&E's proposed rules for changing rates for future revenue requirement changes in order to present rate levels that would be in effect at the end of the proposed four-year revenue allocation glide path.

F. Organization of This Exhibit

Exhibit (PG&E-3) has a total of 10 chapters. The remainder of this exhibit is organized as follows:

- Chapter 2 – Describes the revenue allocation methods used for each of PG&E's functional revenues;
- Chapter 3 – Sets forth PG&E's residential class rate design proposals;
- Chapter 4 – Sets forth PG&E's C&I rate design proposals;
- Chapter 5 – Sets forth PG&E's agricultural rate design proposals;
- Chapter 6 – Sets forth PG&E's streetlight class rate design proposals;
- Chapter 7 – Sets forth PG&E's BEV rate design proposals;
- Chapter 8 – Sets forth PG&E's proposal for continuing the Economic Development Rate Program;
- Chapter 9 – Describes PG&E's proposals for updating fees for DA and CCA customers; and
- Chapter 10 – Describes PG&E's proposals for Implementation and ME&O.

G. Conclusion

In this chapter, PG&E discusses the general policy objectives that underlie its Revenue Allocation and Rate Design proposals, including continuing to make progress towards rates that are: economically-efficient, cost-based, and promote equity among customers, as balanced with other objectives. This chapter also summarizes our revenue allocation proposal, as well as our proposed guidelines for designing rates in this proceeding. PG&E respectfully requests approval of its Revenue Allocation and Rate Design proposals (other than RTP) in this track of the bifurcated GRC Phase II proceeding.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

REVENUE ALLOCATION

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CHAPTER 2
REVENUE ALLOCATION

A. Introduction

This chapter presents Pacific Gas and Electric Company's (PG&E) proposed revenue allocation for all of its retail customer classes,[1] as well as the new Business Electric Vehicle (BEV) class (discussed in Section D below). Revenue allocation (RA) is the process of taking PG&E's revenue requirements for each rate component and allocating them across all customer classes. For rate components that have marginal costs (distribution and generation), the California Public Utilities Commission (CPUC or Commission) has long favored the use of allocating in proportion to Marginal Cost Revenue (MCR) as a just and fair method of allocation.[2] MCR is the revenue that the utility would receive if all rates were only marginal cost. Because average costs are generally higher than marginal costs because of the addition of non-marginal costs, the revenue requirement is generally higher than the MCR. Allocating revenue requirement in proportion to MCR means that if a customer class contains 30 percent of the MCR, it should have 30 percent of the revenue requirement. This is equivalent to saying that fixed costs should be allocated proportionally to marginal costs. This is the Equal Percent of Marginal Cost (EPMC) method, and the ratio of revenue requirement to MCR is known as the EMPC multiplier.[3]

B. Summary of Proposals

PG&E's proposals in this proceeding seek to adjust the revenue allocations to be more aligned with marginal costs. When a customer class's revenue allocation is exactly proportional to MCR, we say that class is paying its "full cost of service" or "full cost rates." PG&E's goal is to get the customer class's

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1 Residential, Small Light & Power, Medium Light & Power, Large Light & Power, Industrial, Standby, Agricultural, and Streetlighting.

2 "Since 1981, this Commission has used marginal cost principles to allocate the revenue requirement and to guide the design of specific rates." D.96-04-050; 65 CPUC.2d 362; 1996 Cal. PUC LEXIS 270 *269, Finding of Fact 1.

3 The EPMC multiplier adjusts Revenue Requirement for certain items like the California Alternate Rates for Energy (CARE) discount and other non-allocated items before taking the ratio.

revenue allocation as close as possible to paying their full cost of service because doing so advances the cost causation principles supported by the CPUC and discussed further in Section D below. Therefore, classes currently allocated more than their proportion are paying more than their cost of service and should have their rates lowered to reflect the costs they actually cause. Conversely, classes currently allocated less than their fair proportion are paying under their cost of service and should have their rates increased to fully cover the costs they cause on PG&E's electric system.

In this 2023 General Rate Case Phase II (GRC II), PG&E proposes changes to revenue allocation to bring each classes' revenue responsibility closer to their cost of service. Revenue allocation has remained far away from cost-of-service levels for the past several decades because of several factors. The main factor has been the previous string of non-precedential settlements that spanned 20+ years, leading to a lack of Commission-approved marginal costs. The lack of approved costs made parties wary of large revenue allocation changes, until PG&E's 2020 GRC II when marginal costs were established by the Commission after full litigation, rather than a settlement.[4] In early 2020, the coronavirus (COVID-19) pandemic caused an uncertain economy including high unemployment. These unprecedented economic stressors prompted the parties to reach a revenue allocation settlement that made relatively small allocation changes, even with approved costs.[5] As a result, many of PG&E's customer classes remain far from their actual cost of service. Below, Table 2-1 summarizes how far away from cost the customer classes were for the last several GRC II cases and the limited progress that was made towards cost of service:

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4 See, *e.g.*, D.21-11-016, p. 166, Ordering Paragraphs (OP) 1-3.

5 *Id.* at pp. 77-78.

TABLE 2-1
MOVEMENTS TOWARDS MARGINAL COST FOR THE LAST SEVERAL GRC'S

Line No.	GRC II	Full Cost Adjustments Needed	Actual Adjustment (Settlements)
1	2011 GRC	-10% to +11%	-2.8% to +1.5%
2	2014 GRC	-6% to +21%	±0.9%
3	2017 GRC	-7% to +55%	±0.7%
4	2020 GRC	-10% to +12%	±1.5%
5		Comparison to This GRC	
6	2023 GRC	-20% to +15%	N/A

In this GRC II, PG&E proposes to make more significant movements towards cost of service than was achieved in years past. Specifically, PG&E's proposal is to move most customer classes one-fourth of the way to full cost of service each year over a four-year period. For customer classes that exceed a bundled rate increase of 8 percent, PG&E proposes to move one-fourth of the way towards an 8 percent cap per year. By the end of the fourth year, PG&E believes that revenue allocation should be close to the actual cost of service for most classes. See Section F for more details.

Aligning revenue allocation more closely with cost causation provides the basis for more accurate rates that send accurate price signals which incentivize customers to better manage their usage to support state policy goals like electrification to reduce greenhouse gases (GHG), conservation, and load shifting (moving energy usage from high cost on-peak hours to lower-cost off-peak times of day). These changes help bring down all customers' rates by reducing total generation costs. Cost-based revenue allocation will also provide rate relief to many classes who have been systematically overpaying for several years.

PG&E bases its illustrative revenue allocation on the same general methods proposed in its 2020 GRC II proceeding. In Decision (D.) 21-11-016, the decision approving the settlements filed in that proceeding, the Commission adopted two approaches for revenue allocation. The first approach provided methodologies to be used for the initial allocation of costs following that decision,[6] while the second approach provided methodologies to be applied between GRC II proceedings (discussed further below).

As to the first approach, Table 2-2, below, provides a summary of the current and proposed allocation methods for distribution, generation and Public Purpose Program (PPP) functional revenues approved for use in the initial allocation:

6 D.21-11-016, p. 168, OP 15, implementing the Marginal Cost/Revenue Allocation Settlement.

TABLE 2-2
CURRENT AND PROPOSED ALLOCATION METHODS

Line No.	Functional Revenue Category	Customer Group[(a)]	RA Methods adopted in 2020 GRC II (Approving Parties' Settlement)[(b)]	RA Methods Proposed in This 2023 GRC II
1	Distribution – Wildfire, Catastrophic Events Memorandum Account (CEMA), and Hazardous Substance Mechanism (HSM)	All customers	Allocated per the formula provided in settlement and approved in D.21-11-016.	No change.
2	Distribution – other rate components[(c)]	All customers	EPMC, limited through application of caps and floors on Direct Access (DA) and Community Choice Aggregation (CCA) customers.	EPMC, moving one quarter of the way towards EPMC each year for 4 years.
3	Generation	Bundled service customers	EPMC, limited through application of caps and floors on bundled customers.	EPMC, moving one quarter of the way towards EPMC each year for 4 years, up to an 8 percent bundled rate impact.
4	PPPs – CARE Surcharge	All customers	All CARE distribution and Conservation Incentive Adjustment (CIA) rate differences will be funded through the CARE surcharge, which will be allocated based on equal cents per kilowatt-hour (kWh). Set once per year.	No change.
5	PPPs – Self-Generation Incentive Program (SGIP)	All customers	Allocated as specified by Resolution E-4926.	No change.
6	PPPs – Tree Mortality and Bioenergy Market Adjusting Tariff (BioMAT)	All customers	Allocated by the 12 Coincident Peak method.	No change.
7	PPPs – Other Non-CARE Surcharge Revenue	All customers	Allocated on percent of total revenue share with generation imputed for DA/CCA customers.	No change.

(a) "All customers" includes eligible Bundled, DA, CCA, and Departing Load (DL) customers.
(b) "Settlement" refers to the Marginal Cost/Revenue Allocation Settlement adopted in D.21-11-016.
(c) Some demand response distribution programs have special allocations specified in the settlement. No change to those allocations is proposed.

Table 2-3, below, provides a summary of the current allocation methods for other functional revenues that PG&E is not proposing to adjust in this proceeding.

TABLE 2-3
CURRENT ALLOCATION METHODS FOR OTHER FUNCTIONAL REVENUE

Line No.	Functional Revenue Category	Customer Group[(a)]	Currently-Approved Allocation
1	Wildfire Fund Charge	All non-CARE/FERA customers	Equal cents per kWh
2	Competitive Transition Costs	All customers	Top 100-hour allocation
3	Nuclear Decommissioning	All customers	Equal cents per kWh
4	Transmission Rates (including the Transmission Revenue Balancing Account Adjustment (TRBAA), Transmission End-Use Customer Refund Adjustment (T-ECRA) and Transmission Access Charge Balancing Account (TACBA) rate)	All customers	12 coincident peak demands (Transmission and T-ECRA) and equal cents per kWh (TACBA and TRBAA)[(b)]
5	Reliability Services	All customers	12 coincident peak demands
6	Energy Cost Recovery Amount	All customers	Equal cents per kWh
7	New System Generation Charge	All customers	12 coincident peak demands
8	Wildfire Hardening Charge	All non-CARE/ Family Electric Rate Assistance (FERA) customers	Allocated by the special allocation for Wildfire, CEMA, and HSM at the time of issuance and held for the duration of the bond
9	Recovery Bond Charge & Credit	All non-CARE customers	Equal cents per kWh
10	CIA[(c)]	All residential customers	Set residually, reflecting decrements from or increments to schedule rates, to preserve the tiered residential total rate structure pursuant to the constraints set forth D.15-07-001
11	Power Charge Indifference Adjustment[(d)]	All eligible customers	Set by vintage in accordance with D.18-10-019

(a) “All customers” includes eligible Bundled, DA, CCA and DL customers.
(b) Transmission rates are established by the Federal Energy Regulatory Commission and are not subject to change by the CPUC in this proceeding.
(c) PG&E has not changed its approach to CIA design, but CIA rates are affected by changes to other charges made in this proceeding.
(d) Although PG&E is not seeking approval for the PCIA allocation in this application, the proposed rates shown here will adjust bundled PCIA allocations to be proportional to the new generation allocators in order to mimic their likely impact.

Finally, the second approach approved by the Commission established the revenue allocation methodologies to be applied for revenue requirement changes between GRC II proceedings.[7] In maintaining that process for changes between GRC II proceedings, PG&E proposes: (1) to continue to apply the methods set forth in Table 2-2 for all specially allocated revenue requirement charges; (2) use equal percent changes all for all other distribution and generation rates; and (3) to continue to apply all the methods set forth in Table 2-3 for other functional revenues. These proposed methods are the same methods that currently apply from the 2020 GRC II and will apply unless specifically addressed in class-specific rate design chapters.

C. Organization of the Rest of This Chapter

The remainder of this Chapter consists of the following sections:

- Section D: Background;
- Section E: Model Changes Since PG&E's Last GRC II;
- Section F: Marginal Cost Revenue Calculations and Full Cost Retail Average Rates;
- Section G: Distribution Allocation;
- Section H: Generation Allocation;
- Section I: Public Purpose Program Allocation; and
- Section J: Implementation of Rate Changes.

In addition, the following information regarding revenue allocation can be found in Exhibit (PG&E-4):

- Appendix B: Present and proposed revenues after revenue allocation;
- Appendix C: Present and proposed rates for all schedules with revenue allocation impacts; and
- Appendix H: NEM and non-NEM full cost of service analysis.

D. Background

1. The 2020 GRC II Revenue Allocation Proposal

In PG&E's 2020 GRC II, our original revenue allocation proposal, filed in late 2019, was to move one-sixth of the way towards full cost every year for

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[7] A.19-11-019, PG&E's Motion for Adoption of Revenue Allocation Supplemental Settlement Agreement (Apr. 8, 2021), Attachment 1, pp. 12-13, approved in D.21-11-016.

3 years.[8] That original proposal envisioned that the second phase of the transition plan, and whether to continue with the original movement to full costs, would be reassessed after 3 years in this 2023 GRC II, using updated marginal costs .[9]

Just a few months after PG&E filed that original 2020 GRC II proposal, the COVID-19 pandemic started, unemployment rose, and everyone was unsure how long it would take to return to normalcy. Intervenors also argued that customers were still getting used to the new time-of-use (TOU) periods set in the 2017 GRC II and did not want to compound that with large revenue allocation changes in the 2020 GRC II.[10] Through settlement discussions, PG&E ultimately agreed with intervenors that smaller changes to revenue allocations were appropriate under those circumstances. The CPUC's decision in PG&E's 2020 GRC II adopted that settlement.[11]

Because the COVID-19 pandemic and its effects have subsided since that decision, PG&E proposes to get back on track for achieving the goal of establishing full-cost rates on a reasonable timeline. Many of the customer classes that PG&E's marginal cost analyses show as being below their true costs of service have been below cost for over a decade, while many other classes have been paying more than their true cost of service for just as long. A foundation for the goal of making rates more equitable is to accurately reflect costs of service, so every customer pays the right proportion of PG&E's overall adopted revenue requirement through their rates, without the existing cross-class subsidies that do not represent the fair share each class should actually be covering.

2. Importance of Aligning Rates with Costs

As also discussed in Chapter 1, aligning revenue allocation with cost of service fulfills many of the Commission's Rate Design Principles that were recently updated in the Demand Flexibility Phase 1 proceeding:[12]

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8 A.19-11-019, Exhibit (PG&E-3), p. 2-1, lines 9-11.

9 *Id* at p. 2-1, lines 11-13.

10 See*, e.g.*, A.19-11-019, Exhibit Cal Advocates-01, p. 6-9, lines 1-21.

11 D.21-11-016, pp. 84-86.

12 D.23-04-040.

1) All residential customers (including low-income customers and those who receive a medical baseline or discount) should have access to enough electricity to ensure that their essential needs are met at an affordable cost.
2) Rates should be based on marginal cost.
3) Rates should be based on cost causation.
4) Rates should encourage economically efficient (i) use of energy, (ii) reduction of GHG emissions, and (iii) electrification.
5) Rates should encourage customer behaviors that improve electric system reliability in an economically efficient manner.
6) Rates should encourage customer behaviors that optimize the use of existing grid infrastructure to reduce long-term electric system costs.
7) Customers should be able to understand their rates and rate incentives and should have options to manage their bills.
8) Rates should avoid cross-subsidies that do not transparently and appropriately support explicit state policy goals.
9) Rate design should not be technology-specific and should avoid creating unintended cost-shifts.
10) Transitions to new rate structures should: (i) include customer education and outreach that enhances customer understanding and acceptance of new rates, and (ii) minimize or appropriately consider the bill impacts associated with such transitions.

Indeed, six of the ten Rate Design Principles center on cost-causation, economic use of assets, and avoiding the cost shift (subsidies) that arise when rates deviate from cost. This does not mean the other Rate Design Principles should be ignored; indeed PG&E supports CARE discounts, economic development programs, and the Commission's other adopted policy reasons that can justify a deviation from a purely marginal cost-based rate design. However, marginal costs must serve as a starting point for considering how other policy goals might warrant any deviation. Any deviations should be made with intention about the outcome or policy that deviation is seeking to achieve.

3. The Business Electric Vehicle Customer Class

This is the first GRC II where the BEV customer class will be receiving revenue allocations. In 2019, the Commission created the BEV class (at that time called Commercial Electric Vehicles) but revenue allocation was not feasible during the 2020 GRC II because there were no customers on the rates.[13] In the absence of a revenue allocation to this new customer class, D.19-10-055 proscribed rate values for all the rate components, as well as rules for how those components would change with revenue requirement changes.[14] The Commission also ordered PG&E to use only its estimated marginal cost values for distribution revenue, without applying any EPMC scalars.[15] This limitation no longer applies in this GRC II because historical billing determinants and cost of service values are now available. Thus, a full cost of service rate for BEV customers can be and is considered here.

E. Model Changes Since PG&E's Last GRC II

While the main structure of PG&E's Revenue Allocation and Rate Design (RARD) model underlying PG&E's proposals in the 2020 GRC II has largely been preserved for the 2023 case, a few changes have been made to keep the model up to date with the current schedules that PG&E uses to collect revenue. All present rates and billing determinants reflect the current TOU periods and use 2024 billing determinants and July 1, 2024, present rates. While some of the labels in the model may still refer to legacy rate schedules like E-19, those labels should be treated as belonging to the updated schedule (B-19). No legacy rate design is done in this model, as all legacy schedules will expire in 2027, which is approximately when these new rates will be implemented.

Although previously PG&E's revenue allocation and average rates calculations had assumed all Residential customers were taking service on Schedule E-1 (a non-TOU rate), now PG&E's default residential rate for the Residential class is Schedule E-TOU-C. While actual residential customers take service on a variety of rate schedules, all customers on a TOU schedule are now

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[13] D.19-10-055, p. 44.

[14] *Id*. at p. 73, OP 1.

[15] *Id.*, at p. 76, OP 14

mapped to E-TOU-C for the determination of present rates and revenue allocations. Schedule E-1 (non-TOU rate) is still shown in the model and represents all customers not on a TOU rate. This updated approach better reflects today's reality for PG&E's residential customers now that we have completed our default TOU transition.

The new BEV schedules have also been added.

F. Marginal Cost Revenue Calculations and Full Cost Retail Average Rates.

PG&E developed MCRs for distribution and generation based on the marginal costs discussed throughout all the chapters in Exhibit 2. Except for marginal customer costs, PG&E developed all the types of MCR on a per-kWh basis, (1) separately for Net Energy Metering (NEM) and non-NEM customers, and (2) separately for delivered and received energy as applicable. These marginal cost values are then multiplied by the forecasted kWh of each schedule to determine each schedule's MCR. Marginal customer costs are multiplied by forecasted customer months to determine marginal customer cost revenue.

These MCRs are used to create the EPMC allocation factors. After the removal of certain non-allocated revenues, described in Sections G and H below, the remaining revenue requirements for distribution and generation are allocated in direct proportion to the MCRs for each schedule. Table 2-4 below shows the full-cost average rates that would result from that allocation. Unlike prior GRCs, PG&E is only highlighting the bundled average rate change in these tables. While the impact to DA/CCA customers is provided in workpapers to this chapter, PG&E does not believe those rate impacts are meaningful because they only include the rate changes to PG&E's portion of the bill. Because most CCAs mirror PG&E's rate changes, the total rate impact to CCA customers will likely be very similar to the bundled impacts given.

TABLE 2-4
AVERAGE BUNDLED FULL COST RATES COMPARED TO PRESENT

			Present Rate	Full Cost Rate		PG&E Proposal		
Line No.		GWh	(¢/kWh)	(¢/kWh)	Total Change	(¢/kWh)	Total Change	Annual Change
1	Residential	11,709	35.1	37.0	4.6%	37.2	4.9%	1.2%
2	Small	2,987	41.3	40.6	(1.7)%	40.7	(1.5)%	(0.4)%
3	Medium	2,537	37.1	33.6	(9.3)%	33.7	(9.1)%	(2.3)%
4	B-19	3,442	31.4	28.4	(9.3)%	28.5	(9.0)%	(2.3)%
5	Streetlights	74	53.7	38.2	(20.0)%	38.3	(19.8)%	(5.4)%
6	Standby	388	21.0	22.8	8.5%	22.7	8.0%	1.9%
7	Agriculture	4,046	37.3	40.8	9.4%	40.3	8.0%	1.9%
8	B-20 T	2,153	19.2	19.4	1.0%	19.3	1.4%	0.3%
9	B-20 P	1,620	26.5	25.1	(5.1)%	25.2	(4.8)%	(1.2)%
10	B-20 S	248	31.1	28.2	(9.2)%	28.3	(9.0)%	(2.3)%
11	BEV	188	24.9	28.7	15.1%	26.9	8.0%	1.9%
12	Total	29,393	33.9	34.3	1.0%	34.3	1.0%	0.3%

PG&E proposes to mitigate the rate changes that would result from a full-cost allocation by only moving one-quarter of the way to full cost each year, for four years, capping the total bundled rate change to 8.0 percent. This proposal attempts to reasonably balance PG&E's objective to move to full-cost revenue allocation while also providing rate stability by utilizing a glidepath approach and the cap ensures that all classes will not see revenue allocation increases of more than about 1.9 percent per year due to compounding. Most classes will see increases of much less than 1.9 percent per year. A 1.9 annual increase for the three classes at the cap (Standby, Agriculture, and BEV) is reasonable given how far away from full cost they are. Both Standby and BEV have present rates that are far below the system average, and they would continue to have some of the lowest rates even with the proposed increase.[16] The Agriculture class is PG&E’s most expensive class to serve and the last several GRCs have shown that Agriculture has been below its cost of service for over a decade.

In the 2027 GRC II, PG&E plans to revisit the marginal costs and revenue allocations of all classes with the intent to have a new proposal for all classes with updated information. Transitioning all classes to their full cost of service is

16 BEV’s current rates have had significant temporary discounts over the last few years. See Chapter 7 in this exhibit (PG&E-3) for more details.

both fair and reasonable, and supports the conclusions made in the 2020 GRC II:

> As a matter of fairness, those customers and customer classes that are less expensive to serve should enjoy the benefit of that status, and those customers that cost more to serve should see that status reflected in their rates.[17]

On a related note, the results of Table 2-4 differ from those in Appendix H because Table 2-4 is limited by the rate design rules currently in place for NEM whereas Appendix H shows the full cost difference between NEM and non-NEM. Specifically, in Table 2-4 the rate design for NEM and non-NEM customers must be the same, and NEM customers get full or partial retail credit for non-bypassable charges (NBC) on energy returned to the grid.[18] Revenue allocations must be applied to each schedule for NEM and non-NEM combined since the two groups cannot be given independent revenue responsibilities while they continue to have identical rates. While full retail credit is given for transmission and NBC revenues, PG&E continues to apply the EPMC scaling only on energy delivered to the customer and not on received energy, similar to the treatment outlined in Appendix H.[19] This is done because it more accurately reflects the benefits of received energy for PG&E and can be applied to the combined group without specifically changing NEM rates.

G. Distribution Allocation

As discussed above, PG&E proposes to allocate its distribution revenue requirement based on distribution MCR, mitigated by moving one-fourth of the way to full cost each year. To achieve this transition, PG&E has developed percentage changes that would be applied to modify present rate distribution revenues for each class on implementation and during the subsequent three

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17 D.21-11-016, p. 162, Conclusion of Law 2.

18 NEM 1.0 customers get full retail credit for NBCs, while NEM 2.0 customers do not get the credit on a subset of NBCs. The recently approved Net Billing Tariff has not been incorporated into the model because there isn’t historical data for these customers to create billing determinants.

19 The MCR for received load is small compared to delivered load (about 4 percent of the total). PG&E has modeled the impact from applying the EPMC scaling to received load and the overall rate impact is minimal (less than 1 percent for all classes).

Annual Electric True-Up (AET) proceedings. These distribution changes are listed in Attachment A.

PG&E will continue to directly assign to each schedule the estimated CARE program discounts and certain non-allocated distribution revenues (i.e., Electric Base Interruptible Program discounts, economic development discounts, employee discounts, other standby revenue, and streetlight facilities charges).

PG&E proposes to keep the special allocations for all the programs specified in the 2020 Revenue Allocation Settlement, including the special allocation rules provided for Wildfire and HSM costs.[20] Because a portion of the wildfire allocator depends on total revenue, this allocation changes slightly with any revenue allocation changes. The BEV class should now start using this allocation of distribution revenues, rather than using the rates dictated by D.19-10-055, because cost of service allocations are now available.

H. Generation Allocation

As in Section G, PG&E proposes to allocate its generation revenue requirement based on generation MCR. PG&E proposes to mitigate the rate changes that would result from a full-cost allocation by only moving one-fourth of the way to full cost each year. In addition, generation rate changes are modified in order to cap the total bundled rate change to 8.0 percent. This capping creates a small generation shortfall which is made up by uncapped classes. To achieve this transition, PG&E has developed percentage changes that would be applied to modify present rate generation revenues for each class on implementation and during the following three AET proceedings. These generation changes are listed in Attachment A.

Although PG&E is not seeking approval for changing the PCIA allocation in this application, the proposed rates shown here will adjust bundled PCIA allocations to be proportional to the new generation allocators to mimic their likely impact. This is similar to what was done for the 2020 GRC rate impacts. The BEV class should now start using this allocation of generation and PCIA revenues rather than using the rates dictated by D.19-10-055, because cost of service allocations are now available and proxy methods are no longer needed.

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[20] D.21-11-016, PG&E's Motion for Adoption of Revenue Allocation Supplemental Settlement Agreement (Apr. 8, 2021), Attachment 1, pp. 9-12, approved in D.21-11-016.

I. Public Purpose Program Allocation

PPP Revenue currently contains four separately allocated components: (1) the CARE surcharge which funds the cost of the income-qualified CARE Program; (2) the SGIP; (3) Tree Mortality; and (4) all other programs including the Electric Program Investment Charge and Former Energy Efficiency (EE) Public Goods Charge, Procurement EE, and Energy Savings Assistance.

The current allocation of these programs can be found in Table 2-2 above. PG&E is not proposing any changes to these allocations but will be refreshing the total revenue allocation for the programs using that allocator. The BEV class should now start using this allocation of PPP revenues rather than using the rates dictated by D.19-10-055, because proxy methods are no longer needed.

J. Implementation of Rate Changes

In this section, PG&E describes its proposal to implement rates resulting from this proceeding as well as its proposal to implement rates arising from future revenue requirement changes.

The total rate levels PG&E will implement after a final decision in this proceeding depends on the RARD methods approved in this proceeding, as well as the current revenue requirements at the time of adoption. Illustrative rates provided in this exhibit are based on revenues collected by current rates (effective July 1, 2024) using forecasted 2024 billing determinants. As a result, the illustrative revenues: (1) do not include any forecast of future revenue requirement changes, and (2) are not based on the sales forecasts that will be actually used to set rates.

If PG&E's proposal is approved, the initial rate change resulting from a decision in this proceeding will be implemented as soon as practicable. Assuming there are revenue requirement and sales forecast changes between now and then, the rate change would be conducted in three steps: (1) create interim rates based on the revenue requirements and sales forecasts used in this proposal; (2) adjust the distribution and generation revenues by the amounts listed in Attachment A; and then (3) allocate the revised revenue requirements pursuant to any subsequent rate changes and sales forecasts, using the guidelines set forth below.

In general, PG&E proposes to continue the existing guidelines for rate changes to implement revenue requirement changes as adopted in

D.21-11-016. PG&E's proposed guidelines are set forth in Attachment B to this chapter and apply to all rate components except distribution and generation. Distribution and generation rules for rates changes are discussed in each rate design chapter.

K. Conclusion

PG&E's respectfully requests that the Commission approve our proposed methodological improvements and the resulting full-cost allocation with an 8.0 percent cap, shown in Table 2-4, as well as PG&E's four-year transition glidepath to full cost of service, shown in Attachment A.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT A

REQUIRED DISTRIBUTION AND GENERATION CHANGES FOR EACH YEAR OF THE TRANSITION PLAN

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CHAPTER 2
ATTACHMENT A
REQUIRED DISTRIBUTION AND GENERATION CHANGES FOR EACH YEAR OF THE TRANSITION PLAN

A. Introduction

As described in Chapter 2, Sections G and H, the table below indicates the percent changes required to distribution revenue and generation revenue in order to move each rate schedule to full cost of service over a four-year transition plan. Please note that the percentage increases in this table will be compounded annually, so individual increases will be smaller than ¼ of the total increase. For example, if a 40 percent increase is needed to reach cost of service in four years, the annual increase will not be 10 percent per year, but rather

$$(1 + 0.40)^{\left(\frac{1}{4}\right)} - 1 = 8.78 \text{ percent}.$$

TABLE 2A-1
REQUIRED DISTRIBUTION AND GENERATION CHANGES FOR EACH YEAR OF THE TRANSITION PLAN

Line No.	Schedule	Distribution Annual Change	Generation Annual Change
1	E-1	1.5%	1.1%
2	EL-1	1.5%	1.1%
3	ETOUC	1.5%	1.1%
4	ELTOUC	1.5%	1.1%
5	B-1	(0.2)%	(1.1)%
6	B-6	(0.2)%	(1.1)%
7	B-15	(0.2)%	(1.1)%
8	TC-1	(0.2)%	1.7%
9	B-10T	(4.1)%	3.3%
10	B-10P	(7.9)%	(0.7)%
11	B-10S	(3.3)%	(2.9)%
12	B-19T	(2.9)%	(0.7)%
13	B-19T V	(2.9)%	(0.7)%
14	B-19P	(3.3)%	(0.4)%
15	B-19P V	(3.3)%	(0.4)%
16	B-19S	(4.7)%	(2.3)%
17	B-19S V	(4.7)%	(2.3)%
18	Streetlights	(22.7)%	0.6%
19	Stby B-20 T	1.2%	3.2%
20	Stby B-20 P	1.2%	(3.5)%
21	Stby B-20 S	1.2%	3.2%
22	AG-A1	3.3%	0.2%
23	AG-A2	3.3%	0.1%
24	AG-B	3.3%	0.6%
26	AG-C	3.3%	1.4%
27	B-20T	(1.5)%	0.6%
28	B-20P	(2.8)%	(1.1)%
29	B-20S	(5.7)%	(1.3)%
30	FPP T	(1.5)%	0.6%
31	FPP P	(2.8)%	(1.1)%
32	FPP S	(5.7)%	(1.3)%
33	BEV-1 S	48.9%	(5.7)%
34	BEV-2 S	48.9%	(5.7)%
35	BEV-2 P	48.9%	(5.7)%

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT B

RATE DESIGN GUIDELINES TO IMPLEMENT REVENUE REQUIREMENT CHANGES

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
ATTACHMENT B
RATE DESIGN GUIDELINES TO IMPLEMENT REVENUE REQUIREMENT CHANGES

The following guidelines will be applied to changing rates for revenue requirement changes subsequent to the decision in the Pacific Gas and Electric Company's (PG&E) 2023 General Rate Case Phase II (GRC II) proceeding, until the effective date of implementation of a decision in Phase II of PG&E's next GRC proceeding.

a) Revenue requirement changes will be identified by function (e.g., nuclear decommissioning, generation, etc.). Each customer class and schedule will be allocated the average percentage change in functional revenue necessary to collect the functional revenue requirement. This approach to allocating costs using a System Average Percentage Change (SAPC) by function will be employed such that each customer group's share of each functional revenue requirement remains approximately the same. For schedules that are designed together, such as schedules that are designed on a revenue neutral basis, the SAPC by function will be applied to the combined rate design group.

b) Generation revenue developed to determine the appropriate starting point to apply the percentages from Section (a) above will exclude directly assigned revenue (i.e., other standby revenue). For the rate changes where there is a change to Competitive Transition Costs (CTC), current generation revenue used for purposes of allocation will be determined after the change to CTC is incorporated, consistent with current practice.[1]

c) CTC will be allocated based on the 100 peak hour allocation method. 100 peak hour allocation factors for CTC will be revised each year based on the most recent available information at the time PG&E files its annual Energy Resource Recovery Account (ERRA) forecast application consistent with current practice. The New System Generation Charge and (for eligible customers) the Power

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1 In addition, generation adjustments for SmartRate™ and Peak Day Pricing (PDP) will be deducted from the generation revenue to be allocated as approved by the California Public Utilities Commission (CPUC or Commission).

Charge Indifference Adjustment (PCIA) will be developed consistent with current practice.[2]

d) Distribution revenue (including the Conservation Incentive Adjustment (CIA)) developed to determine the appropriate starting point to apply the percentages from Section (a) above will exclude directly assigned revenue (including, but not limited to, other standby revenue, streetlight facilities charges, meter charges, employee discounts, and the Schedule B-15 facilities charge), specially allocated revenues (including but not limited to Wildfire and Hazardous Substance Mechanism revenues, demand response programs, and the CPUC fee), as well as estimated California Alternate Rates for Energy (CARE) Program discounts.

e) Public Purpose Program (PPP) rates will be developed as the sum of the following four pieces and will be allocated as follows:

   1) The cost of the CARE Program will be determined and the CARE surcharge will be set once per year in the Annual Electric True-Up (AET) proceeding based on the difference between CARE and non-CARE rates excluding the CARE surcharge, Self-Generation Incentive Program (SGIP) incentives funded through PPP, California Solar Initiative (CSI) incentives funded through PPP, the Recovery Bond Charge & Credit, and the Wildfire Hardening charge. The cost will be allocated to eligible customers on an equal cents per kilowatt-hour (kWh) basis and collected through the CARE surcharge component of PPP rates.

   2) SGIP revenue allocated as specified by Resolution E-4926.

   3) Tree Mortality and Bioenergy Market Adjusting Tariff revenue allocated by the 12 Coincident Peak method.

   4) The cost of the Energy Savings Assistance (ESA), Procurement Energy Efficiency, Electric Program Investment Charge (EPIC) and Energy Efficiency Public Goods Charge will be allocated to customers based on an equal percent of the sum of new revenue requirement for these programs

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2 In A.17-04-018, PG&E has proposed to replace the PCIA with the Portfolio Allocation Methodology, or PAM. As proposed, PAM and CTC utilize the same allocation and rate design currently used for PCIA and CTC. On June 2, 2017, the Commission established Rulemaking 17-06-026, and dismissed without prejudice A.17-04-018. Any changes that the Commission makes for PAM or CTC rate design in R.17-06-026 will take precedence.

(that is, the same percentage will be applied to the new revenue requirement for each customer group to determine the allocated revenue).

f) The Recovery Bond Charge & Credit, the Wildfire Hardening charge, the Energy Cost Recovery Amount and Nuclear Decommissioning charge shall continue to be collected on an equal cents per kWh basis for all eligible customers.

g) Transmission Owner and other Federal Energy Regulatory Commission (FERC) jurisdictional rates shall be set by the FERC.

h) Greenhouse gas allowance returns will be set as specified separately by the CPUC.

i) The costs of the Family Electric Rate Assistance (FERA) program will continue to be assigned to the residential class.

j) Should the Commission approve an entirely new revenue requirement category to be included in rates between the effective dates of the 2023 GRC II and the 2027 GRC II decisions, the revenue allocation and rate design for that new revenue requirement category should be decided by the Commission at that time and the rules governing existing revenue requirement categories will not govern or be precedential for that purpose.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

RESIDENTIAL RATE DESIGN

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
RESIDENTIAL RATE DESIGN

A. Introduction

This chapter presents Pacific Gas and Electric Company's (PG&E or the Utility) rate design proposals for its Residential class of customers, to be implemented pursuant to a decision in Phase II of its 2023 General Rate Case Phase II (GRC II). As described in Chapter 1, "Revenue Allocation and Rate Design Policy" of Exhibit (PG&E-3), these proposals include changes to distribution, Public Purpose Program (PPP), and generation rate components. As discussed in Chapter 1, a key objective of PG&E's residential rate proposal is to use updated marginal cost relationships, balanced with other objectives such as understandability, equity, and rate stability, to set distribution and generation rates.[1] PG&E sets forth its Residential rate design proposals in this testimony, focusing on changes to total bundled rates.

PG&E proposes changes to better align our residential rate portfolio with the state's policy goals of promoting load flexibility and electrification. These changes include updating time-of-use (TOU) rate differentials on all residential TOU rates to better align with PG&E's updated marginal costs, and stabilizing tier differentials to better align PG&E's primary residential rates (E-1 and E-TOU-C) with the state's updated rate design principals to encourage beneficial electrification.[2]

B. Summary of Residential Rate Proposals

In summary, PG&E's residential rate design proposals are as follows

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[1] PPP rates for the residential customer class are designed in accordance the guidelines described in Chapter 1 of this exhibit (PG&E-3).

[2] See D.23-04-040, Updating Rate Design Principles.

TABLE 3-1
SUMMARY OF PG&E'S 2023 GRC II PROPOSED RESIDENTIAL RATE DESIGN CHANGES

Line No.	Rate Schedule/Issue	2020 GRC II Settlement Adopted Rate Design Changes	2023 GRC II Proposed Rate Design Changes
1	Baseline Quantities (BQ) (E-1 and E-TOU-C)	Updated BQs using the latest input data, subject to caps on the changes.	Update BQs using the latest input data and rename "All Electric" to "Electric Space Heating" for customers who use electricity for their space heating needs to eliminate customer confusion.
2	Tiered Rate Differentials (E-1 and E-TOU-C)	No changes to tiered rate differentials from previously adopted policy.	Reduce E-1 and E-TOU-C differentials between Tier 1 and Tier 2 rates to $0.06/kilowatt-hour (kWh),[a] and then retain those differentials until explicitly revisited in a future GRC II, Rate Design Window (RDW), or other ratesetting proceeding.
3	E-TOU-C TOU Differentials	Adopts three step transition to increase TOU differentials to be $0.123/kWh in the summer and $0.03/kWh in the winter.	Adopt three step transition to increase summer TOU differentials to $0.24/kWh and winter TOU differentials to $0.036/kWh by 2029.
4	E-TOU-D	Update TOU rate differentials to move closer to marginal cost differentials.	Update TOU rate differentials to move toward marginal cost differentials as calculated in this proceeding.
5	E-ELEC	Created rate, with TOU periods modeled on Electric Vehicle (EV)2, TOU differentials based on marginal cost differentials, and a $15 fixed charge. Restricted to customers with certain technologies.	Update TOU rate differentials to move toward marginal cost differentials as calculated in this proceeding. These changes are independent of fixed charge changes approved in D.24-05-028.
6	EV2	No design changes, per 2017 GRC II settlement.	Update TOU rate differentials to move closer to marginal cost differentials as calculated in this proceeding and eliminate 800 percent of baseline requirement
7	SmartRate™	No changes to SmartDay event requirements.	Eliminate the minimum event days requirement to avoid unnecessary events during mild summers.
8	Minimum Bill Revisions	Eliminate Medical Baseline, California Alternate Rates for Energy (CARE), and Family Electric Rate Assistance (FERA) 50 percent minimum bill discounts, replaced by otherwise applicable percentage discounts.	In light of the Residential Fixed Charge implementation plan[b] minimum bill revisions pursuant to D.21-11-016[c] and D.20-03-003[d] are no longer required.
9	Master Meter Discounts (MMD)	Strata used for the Diversity Benefit Adjustment (DBA) component of the MMD have changed.	No methodological changes.
10	Rate Changes Between GRCs	Except where explicitly planned otherwise, all rate changes are calculated on an equal-cents-per-kWh basis.	No change.

(a) For Schedule E-TOU-C, the tariff provides stated rates for each TOU period, which represent the Tier 2 rates. The implicit Tier 1 rates are obtained by applying the baseline credit to each of these TOU rates. Thus, the cent-per-kWh rate differential is equal to the negative of the baseline credit.

(b) D.24-05-028, OP 3, p. 162-163; PG&E Tier 3 Advice Letter (AL) 7351-E (August 7, 2024) (pending California Public Utilities Commission (CPUC or Commission) Resolution).

(c) See D.20-03-003, p.36 (in Phase 3 of PG&E's 2018 Rate Design Window Proceeding) and D.21-11-016, OP 16 (approving the Residential Settlement in PG&E's 2020 GRC II proceeding).

(d) See D.20-03-003, OP 2, 3, and 5.

Note that for the purposes of calculating bill impacts, this testimony uses proposed rates based on present rates (as of July 1, 2024) with PG&E's proposed rate design modifications. These proposed rates are then compared with present rates (as of July 1, 2024) to arrive at the bill impacts of proposed rate design changes. This excludes the impacts of revenue requirement allocation changes proposed elsewhere in this application and the impacts of residential rate design changes approved in D.24-05-028. However, for illustrative purposes, the proposed rates in Appendix C include a scenario combining the rate design changes proposed in this application with the fixed charge approved in D.24-05-028.

These proposed residential rate changes, if adopted, would provide more appropriate price signals for incenting more efficient energy usage across a wide range of residential customers.

C. Organization of the Rest of This Chapter and Witness Responsibilities

The remainder of this chapter is organized as follows:

- Section D – Residential Class Background;
- Section E – Baseline Quantity Update;
- Section F – Tiered Rates;
- Section G – TOU Rates;
- Section H – SmartRate;
- Section I – Minimum Bill Revisions;
- Section J – Master Meter Discounts;
- Section K – Diversity Benefit Adjustment;
- Section L – Conclusion.

In addition, the following information regarding residential rate design can be found in Exhibit (PG&E-4):

- Appendix A – Recorded 2023 data for Residential customers;
- Appendix C – Present and proposed total and unbundled rates for residential rate schedules;
- Appendix D – Illustrative bill impact comparisons of PG&E's proposed residential rate design changes;

The witness responsibilities for this chapter are as follows:

- Colin Kerrigan – Sections D (Residential Class Background), F (Tiered Rates), and G (TOU Rates);

- Sarah Jin – Section E (Baseline Quantity Update);
- Natalie Yang – Section H (SmartRate: Eliminating Minimum Number of SmartDay Events Requirement);
- Joseph Au – Section I (Minimum Bill Revisions);
- Hugh Krogh-Freeman – Section J (Master Meter Discounts); and
- Annette Taylor – Section K (DBA).

D. Residential Class Background (Witness: Colin Kerrigan)

As of December 31, 2023, PG&E's Residential class is composed of about 4.97 million active service agreements on rate Schedules E-1, E-TOU-B, E-TOU-C, E-TOU-D, EV-A, EV-B, EV2, E-ELEC, EM, ES, ESR and ET. PG&E is set to eliminate Schedules E-TOU-B and EV-A in late 2025, likely before a final decision in this case. The PG&E residential rate with the largest enrollment is the tiered default TOU rate, Schedule E-TOU-C, with about 50 percent of all our residential customers, followed closely by our tiered Non-TOU Schedule E-1, on which about 40 percent of our customers choose to take service.[3] Table 3-2, below, provides the customer counts and description of the residential rate schedules. Unless specifically noted all customer counts and sales figures in this section are as of December 31, 2023.

PG&E's annual sales to the residential class in 2023 were about 25,510 gigawatt-hours (GWh) (1 GWH = 1 million kWh) or 35 percent of PG&E's total retail electric sales. Income-qualified customers may enroll in either the CARE or FERA discounted rate programs. CARE-enrolled customers comprise about 25 percent of PG&E's residential customers, and FERA customers represent 0.8 percent of residential customers.

In addition to the tiered rates, customers can opt to take service under non-tiered TOU rates. These optional rates have grown steadily since PG&E's 2020 GRC II application, and now collectively constitute about 10 percent of residential customers, which brings the total population of PG&E residential customers who take service on any of our TOU rates to 60 percent. E-TOU-D is open to all customers and features a narrower peak period definition than most other rates (5-8 p.m. on weekdays only); 6 percent of customers take service on

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[3] These percentages include various master metered rates directly based off of Schedules E-1 and E-TOU-C.

this rate. EV2 and E-ELEC share identical TOU period definitions and are restricted to customers with specific technologies. Currently, the primary distinction between these rates is that E-ELEC (0.2 percent of customers) includes a fixed charge, while EV2 (2.3 percent of customers) has higher TOU differentials. E-ELEC was made available to customers in late 2022, and has steadily grown throughout 2023 and 2024.

Schedule EM, which is closed to new installations, provides service to master metered multi-family Residential customers without submetering, including residential hotels as defined in PG&E's Electric Rule 1,[4] and Recreational Vehicle (RV) parks which rent at least 50 percent of their spaces on a month-to-month basis for at least nine months of the year to RV units used as permanent residences. Schedule EM-TOU is a tiered TOU rate with the same eligibility criteria as EM. Schedule ES is open to master-metered multi-family Residential customers that serve sub-metered tenants, excluding sub-metered Mobile Home Parks (MHP). Schedule ESR is open to master-metered residential RV parks or marinas where spaces, slips, or berths are rented on a pre-paid monthly basis to RVs or boats used as permanent residences. Schedule ET is open to Master-Metered Mobile Home Parks (MMMHP) which serve sub-metered tenants. Schedules EM, ES, ESR, and ET currently have the same energy and minimum charges as Schedule E-1, while EM-TOU has the same charges as E-TOU-C. However, D.24-05-028[5] required implementation of the fixed charge on ES, ESR, and ET, but not EM and EM-TOU. While the CPUC indicated plans to adopt a fixed charge on master metered rates without submetering in a future phase of Rulemaking 22-07-005, in the interim that schedule will diverge from other residential rates.[6]

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4 PG&E's Electric Rule 1, available at: <https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_1.pdf> (accessed Sept. 11, 2024).

5 D.24-05-028, Conclusion of Law (COL) 29.

6 *Ibid*. p. 86.

TABLE 3-2
DESCRIPTION OF RESIDENTIAL RATES

Line No.	PG&E Schedule	External Facing Name	Customer Counts[(a)]	Description	Notes
1	E-1	Tiered Rate Plan (Non-TOU)	1,975,000	Formerly default rate; Increasing block rate with two tiers.	
2	E-TOU-B		70,000	Un-tiered TOU Rate	Will be phased out by late 2025
3	E-TOU-C	TOU (Peak Pricing 4-9 p.m. every day)	2,464,000	Default rate; TOU rate with baseline credit mirroring E-1 tiers	
4	E-TOU-D	TOU-Peak Pricing 5-8 p.m. Weekdays	304,000	Un-tiered TOU rate open to all customers; narrower peak period definition than most other TOU rates (5-8 p.m. on weekdays only)	
5	EV-A,	Home Charging	6,000	Un-tiered TOU rate with legacy TOU periods limited to customers with electric vehicles and other qualifying technologies.	Will be phased out by late 2025
6	EV-B		410	Similar to EV-A, but only for customers with a separate meter for their EV charger.	
7	EV2		116,000	Un-tiered TOU rate limited to customers with electric vehicles and other qualifying technologies.	
8	E-ELEC	Electric Home	11,000	Un-tiered TOU rate with a fixed charge; limited to customers with electric vehicles and other qualifying technologies.	
9	EM		16,000	Master metered multi-family Residential customers without submetering, including residential hotels as defined in PG&E's Electric Rule 1, and RV parks which rent at least 50 percent of their spaces on a month-to-month basis for at least nine months of the year to RV units used as permanent residences.	Closed to new installation; Not currently impacted by fixed charges set by D.24-05-028
10	ES		396	Master metered multi-family Residential customers that serve sub-metered tenants, excluding sub-metered MHPs.	
11	ESR		<100	Master metered residential RV parks or marinas where spaces, slips, or berths are rented on a pre-paid monthly basis to RVs or boats used as permanent residences.	
12	ET		1,000	Open to master metered MHPs which serve sub-metered tenants.	

(a) Customer counts as of 12/31/2023. Rounded to the nearest thousand, except for rates with less than 1,000 active customers.

E. Baseline Quantity Update (Witness: Sarah Jin)

1. Introduction

PG&E proposes to update the BQs on its tiered residential electric rate schedules. This update is consistent with the agreement in the Residential Rate Design Settlement (RRD Settlement) in PG&E's 2020 GRC II, adopted by the CPUC in D.21-11-016.[7] In that Settlement, parties and PG&E agreed to update electric BQs in our 2023 RDW Proceeding if PG&E's next GRC II (i.e., the current proceeding) were delayed beyond 2023.[8] However, it turned out that updating BQs would have been the only item PG&E proposed if we were to file a 2023 RDW. For efficiency, the Commission approved[9] PG&E's request to delay the BQ updates to the current GRC II proceeding. In that same request, PG&E expressed the intent to work with interested parties to develop a consensus on the BQ update methodology and to seek fast-tracking this item once the 2023 GRC II application is filed.[10] In preparation of this testimony, PG&E met with the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) and The Utility Reform Network to discuss the BQs. Below, PG&E describes its process in updating the BQs and our proposed BQ updates.

Table 3-3 below shows BQ calculation inputs that were adopted in D.21-11-016 (2020 GRC II) and summarizes PG&E's proposal in this proceeding.

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7 D.21-11-016, pp. 120-121.

8 A.19-11-019, PG&E's Motion for Adoption of RRD Supplemental Settlement Agreement, Attachment 1, p. 17-18, approved in D.21-11-016.

9 Letter request to CPUC Executive Director (Nov. 3, 2023) and letter of approval from CPUC Executive Director (Nov. 14, 2023).

10 Letter request to CPUC Executive Director (Nov. 3, 2023), pp. 2-3.

TABLE 3-3
SUMMARY OF BASELINE QUANTITY CALCULATION INPUTS ADOPTED IN 2020 GRC II VS. PG&E'S PROPOSALS IN THIS PROCEEDING

Line No.	Input	2020 Adopted Items	2023 Proposed Items
1	Historical Usage Data	Oct 2014 through Sep 2018	Update to Oct 2019 through Sep 2023.
2	Forecast Adjustment	Forecast of calendar year 2020	Stop using forecast adjustment to avoid volatility as explained in Section 2.b.
3	Vacation home and propane user exclusion	Exclude usages for vacation homes and propane users (for All-Electric BQs) based on 2009 California Residential Appliance Saturation Study (RASS) survey data	Use more recent 2019 RASS survey data and modify the method to exclude vacation homes and propane users explained in Section 2.c
4	Percentages used for BQs	• 53.8 percent Basic, All Electric Summer • 63.8 percent All Electric Winter	No change.
5	Cap applied	• +/-5 percent for Basic Summer, All-Electric BQs, and • +/-8 percent for Basic Winter BQs	+/-10 percent

Beside the BQ updates, PG&E also proposes to relabel the "All-Electric" BQs to "Electric Space Heating" BQs for better customer understanding.

2. Proposed BQs for Electric Residential Customers

a. Historical Data Update

PG&E's currently adopted electric BQs[11] were calculated using historical data from October 2014 through September 2018, adjusted by the weather-normalized forecasted usage of 2020. In this proceeding, PG&E proposes to use more recent four years of seasonal usage data (for the October 2019 through September 2023 period) to update the BQs.

b. Forecast Adjustment

In its previous 2020 GRC II, PG&E used most up-to-date adopted Energy Resource Recovery Account (ERRA) sales forecast at the time (calendar year 2020) to adjust the historical usage data for the period

[11] The current electric BQs were adjusted in D.21-11-016. The adopted electric allowances were implemented on June 1, 2021.

from October 2014 through September 2018. The forecast adjustment was proposed mainly to mitigate the weather-related fluctuations in baseline allowance levels and to better incorporate changes in customer usage in this era of increasing energy transformation as reflected in the adopted residential sales forecasts.[12] If PG&E were to apply the same methodology in this proceeding, it would use the ERRA sales forecast for calendar year 2025 (which is anticipated to be approved by CPUC near the end of 2024) to adjust the more recent historical data for the period from October 2019 through September 2023.

However, PG&E forecasts that residential usage per customer in 2025 to be lower than the historical 4-year average usage by about ten percent in summer and four percent in winter. In discussions prior to filing our current BQ proposal, stakeholders pointed out that adjusting historical sales for forecasted 2025 usage may be problematic.

Given California's anticipated fast-paced electrification efforts during the next decade, there is a likelihood that usage per customer during the 2026-2030 period (when the updated BQs approved in this proceeding will go into effect) will exceed PG&E's forecasted usage for 2025. For this reason, and since PG&E does not have an adopted sales forecasts for years beyond 2025, PG&E determined it would be prudent, for our current proposal, *not* to apply a forecast adjustment. In its future GRC Phase II proceedings, PG&E will reevaluate the efficacy of applying a sales forecast adjustment to historical customer usage for purposes of developing updated BQs.

c. Vacation Home and Propane User Exclusion

Based on the adopted methodology per D.04-02-057, as modified in D.07-09-004, in past GRC II proceedings PG&E removed estimated: (1) seasonal and vacation home usage from BQ calculations, and (2) propane users' winter usage from the "All-Electric" BQ calculation. These adjustments were based on seasonal vacation home and propane user percentages by baseline territory reported in the 2009 California RASS.

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[12] A.19-11-019, Exhibit (PG&E-3), p. 3-7, line 20 to p. 3-8, line 10.

Now that the more recent 2019 RASS survey results have been published, PG&E initially used the detailed data from 2019 RASS to estimate vacation home percentages (for all BQs) and non-electric space heating (e.g., propane) use percentages (for All-Electric winter BQs) by baseline territory. However, for certain baseline territories, the number of respondents in RASS survey was extremely low. For example, only 22 respondents from baseline Territory Z responded to the question related to the type of space heating system.

Given these small sample sizes, PG&E now is applying the following simplified approach to exclude: (1) seasonal and vacation homes, and (2) propane users in winter. First, PG&E excluded all negative and zero usage customers from the BQ calculation, to prevent low-usage seasonal and vacation homes from skewing the results. Second, to account for propane users for the All-Electric BQ calculations, PG&E excluded winter low usage customer bills based on the overall percent of All-Electric customers who responded on the 2019 RASS that they used non-electric sources for their primary space heating.

d. Percentages Used for BQ

In the 2020 GRC II Residential Rate Design Settlement, the parties agreed to develop the electric BQs based on the target percentages of usage adopted by the Commission in D.18-08-013, which is 53.8 percent for Basic Use and All-Electric summer season and 63.8 percent for All-Electric winter season.[13] In this proceeding, PG&E proposes to keep those same percentages.

e. Caps Applied to the Changes to BQs

In the 2020 GRC II Residential Rate Design Settlement, to address concerns about potential large electric bill impacts, the parties agreed to apply caps to the changes in BQs to mitigate such impacts. The caps were designed to ensure that: (a) in summer, no BQ changed by more than five percent; and (b) in winter, no Basic service BQ changed by more than eight percent and no All-Electric service BQ changed by more

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[13] A.19-11-019, PG&E's Motion for Adoption of RRD Supplemental Settlement Agreement, Attachment 1, p. 11.

than five percent. For similar reasons, PG&E proposes to continue to cap deviations from the uncapped calculated results, so that no BQ changes by more than ten percent in either direction. The resulting BQs are presented in the following section.

f. Proposed BQs

Tables 3-4 and 3-5 show PG&E's proposed BQ allowances for individually-metered and master metered electric residential customers, respectively.

TABLE 3-4
NEW DAILY BQs: INDIVIDUALLY-METERED

		4-Year Average			
		Basic Electric		All-Electric	
Line No.	Baseline Territory	Summer	Winter	Summer	Winter
1	P	14.9	11.7	16.1	23.4
2	Q	10.5	11.7	8.4	23.4
3	R	18.6	10.2	20.5	24.0
4	S	16.2	10.3	17.8	22.1
5	T	6.4	7.6	6.4	12.8
6	V	7.8	8.9	11.4	21.0
7	W	19.4	9.5	21.2	18.6
8	X	10.5	9.6	8.4	14.8
9	Y	11.3	11.2	12.1	21.6
10	Z	6.5	8.6	6.3	15.9

TABLE 3-5
NEW DAILY BQs: MASTER METERED

		4-Year Average			
		Basic Electric		All-Electric	
Line No.	Baseline Territory	Summer	Winter	Summer	Winter
1	P	4.5	5.3	8.7	13.8
2	Q	5.3	5.3	6.6	13.8
3	R	7.6	4.9	9.3	11.6
4	S	7.0	5.1	10.0	13.0
5	T	3.4	4.1	4.3	9.2
6	V	4.0	4.8	6.4	11.7
7	W	8.6	4.9	11.0	11.7
8	X	5.3	5.5	6.6	12.7
9	Y	6.8	6.8	7.4	14.6
10	Z	3.9	4.7	4.2	9.9

3. Re-Label "All-Electric" Baseline to "Electric Space Heating" Baseline

To reduce customer confusion and encourage electrification efforts, PG&E is proposing to relabel what are currently referred to as "All-Electric" BQs, by instead calling them "Electric Space Heating" BQs. This proposed change in terminology is motivated by PG&E fielding increasing numbers of questions from customers seeking to electrify their appliance/equipment mix who were confused by the fact that, in certain baseline territories, the summer BQs for Basic Use customers exceeded those for All-Electric customers—which seemed counter-intuitive to them. In fact, though, this situation is not indicative of incorrectly calculated BQs, but rather is due to customers not realizing that customers can qualify for All-Electric BQs without actually residing in all-electric homes.

Currently, despite its name, customers are not required to have all-electric homes to qualify for All-Electric BQs. Rather, to qualify, a customer only needs to use electricity to meet its primary space heating needs. So, it is entirely possible, in any given baseline territory, for an All-Electric BQ in summer to be lower than the corresponding Basic BQ, since Basic Use and All-Electric BQs are calculated separately and independently based on each group's historical usage. Customers who have electric space heating generally have higher historic winter usage than Basic use customers with gas space heating, resulting in their winter electric BQs being set much higher than the winter BQs for Basic Use customers. However, in summer, these electric heating customers may have summer usage that is lower than that of Basic Use customers in the same territory—so their resulting summer BQs will also be lower.

PG&E's use of the term "All-Electric" to describe customers with electric space heating dates back to a time when EVs, Heat Pump Water Heaters (HPWH), and electric stoves were not as common as they are today. Now, with more electric appliances available to customers, "All-Electric" has taken on a new and different meaning. PG&E's proposal to, instead, refer to this group as "Electric Space Heating" customers will more clearly and accurately describe the only requirement necessary for a customer to qualify for the category. A customer may also have additional electric appliances/equipment, but only primary space heating is needed to qualify.

This change in terminology should also make it less confusing for customers to select their best rate option. For example, if a household were to completely electrify by purchasing an EV, HPWH, and electric stove on top of their existing electric space heating (i.e., to convert its entire home to electricity and truly become "All-Electric"), it would likely be able to reduce its average monthly bill by switching from a tiered rate schedule to a non-tiered one such as Schedule E-ELEC, for which BQs are inapplicable. But the current "All-Electric" BQ terminology might confuse the customer and hold it back from making the rate schedule switch, thinking that staying on a rate schedule with the name "All-Electric" attached to has to be the best choice for an all-electric home.

Therefore, to clear up customer confusion and better support electrification efforts, PG&E proposes a change to the terminology used, replacing the "All-Electric" baseline description with "Electric Space Heating" instead. As parties mentioned in the Building Decarbonization Phase IV proceeding, "home electrification is typically completed in phases … and electric baselines can … improve customer economics in partial electrification scenarios."[14] PG&E believes using the "Electric Space Heating" terminology instead would help many customers who switch from gas space heating to electric space heating as their first step towards home electrification. As customers continue to adopt more electrification equipment, such as HPWPs or EVs, tiered rate schedules with baseline allowances are less likely to be their best rate choice. Rather, rate schedules without tiers and baseline allowances such as E-ELEC and EV2 are more likely to bring lower bills. Therefore, this terminology change can help customers on their electrification journey, by better understanding the menu of PG&E rate options available to them as they pursue their electrification journey.

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14 Opening Comments of Vermont Energy Investment Corporation on Assigned Commissioner's July 1,2024 Scoping Memo and Ruling (VEIC Opening Comments) (Aug. 7, 2024), pp. 7-8, available at: <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M537/K565/537565401.PDF> (accessed Sept. 11, 2024).

F. Tiered Rates (Witness: Colin Kerrigan)

1. Introduction

Currently, PG&E's tiered rates are designed such that Tier 2 rates charged to usage above 100 percent of the baseline quantity are 25 percent higher than Tier 1 rates charged to usage below 100 percent of the baseline quantity. PG&E proposes to reduce and freeze tier differentials to $0.06/kWh on all its tiered rates.

In D.15-07-001, the CPUC established a glide path for tiered rates to reach a Tier 2 to Tier 1 ratio of 1.25-to-1.[15] PG&E achieved that ratio in 2019. The Commission also established a High Usage Surcharge (HUS) applying to usage above 400 percent of baseline;[16] however, in 2021, the Commission adopted a path to eliminating this rate design component and PG&E removed the HUS from the E-1 tariff on January 1, 2023. As a result, PG&E's tiered rates now only include the Tier 2 to Tier 1 differential approved nearly a decade ago.[17] While this ratio has now been in place for many years, rising overall rates have resulted in significant increases in actual cent-per-kWh differential between the Tier 1 and Tier 2 rates. While D.15-07-001 estimated that the tier differential would be about $0.05/kWh upon completion of the glide path, it was actually $0.056/kWh when the glide path ended in 2019.[18] As of July 1, 2024, the differential has increased to $0.098/kWh, nearly double what the CPUC planned in 2015.

In the 2020 GRC II proceeding, PG&E proposed that the cent-per-kWh tier differentials be frozen for all rate changes between GRC II cases. However, this proposal was not included in the subsequent settlement agreement, and the status quo continued. Since then, both state law and the broader policy landscape has shifted towards recognizing that rate design must balance incentives to reduce electricity usage against

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[15] D.15-07-001, p. 277.

[16] D.15-07-001, p. 4.

[17] Rate tiers are implemented as a baseline credit on E-TOU-C, rather than having Tier 1 and Tier 2 versions of each TOU rate to improve customer understanding. For the sake of consistency, this section will use the term "tier differentials" when discussing both the difference between Tier 1 and Tier 2 rates and Below Baseline and Above Baseline rates from E-1 (and associated master-metered rates) and E-TOU-C, respectively.

[18] D.15-07-001, p. 275.

incentives to substitute electricity for fossil fuels. High tier differentials may provide the former but work against the latter.

Current statute requires that PG&E continues to offer tiered rates as part of our rates portfolio.[19] However, we propose the incremental step of reducing the tier differential to $0.06/kWh and freezing it at this level until addressed in a future rate setting proceeding, as explained further below.

2. Tier Differential Reduction and Freeze Proposal Is Well Aligned With CPUC Rate Policy

Reducing and freezing tier differentials is well aligned with the CPUC's updated rate design principles, as maintaining high tier differentials disincentivizes beneficial electrification.[20] By artificially making electricity more expensive to use on the margin, tiered rates work at cross purposes to supporting substitution of fossil fuel end uses with electricity. Nor are the existing tiers based on any analysis of marginal costs; they exist primarily because the baseline statute requires them to exist. While there have been arguments that tiers can be a proxy for TOU rates, this is moot in the context of default TOU rates (since the interval data from smart meters allows for actual TOU rates, eliminating the need for proxy rates).[21]

Further, this change recognizes that a percent differential between bundled Tier 1 and 2 rates applies to far fewer customers today than it did in 2015, as only 33 percent of customers take service on tiered bundled rates. The remainder either take generation service from a Community Choice Aggregator (CCA) (which can result in their actual tier differential being higher or lower than 1.25-to-1 depending on their CCA's generations rates) and/or are on a non-tiered rate, and have no tier differential by definition. Of this 33 percent, only about half take service on Schedule E-1, where usage above baseline will always be 25 percent more expensive than usage below baseline. The rest take service on Schedule E-TOU-C, which has a baseline credit designed to provide a 25 percent tier differential on average across all TOU periods, but does not achieve that in any of them. So, a

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19 Public Utilities Code 739(d).

20 D.23-04-040, p. 36, Ordering Paragraph (OP) 1(d).

21 D.15-07-001, pp. 110-114.

customer that uses more electricity during the summer on-peak period than the average customer will pay less than 25 percent more for above baseline usage. Reducing and freezing the tier differential will rationalize this aspect of PG&E's rate design with the current customer landscape.

As shown in Appendix D, the bill impacts of this change (combined with changes to baseline quantities) are modest, with very few customers seeing bill increases greater than 5 percent. This change to tiered rates should be considered a modest step towards a rate portfolio fully aligned with the state's policy objectives. Taking action now to reduce the magnitude of tier differentials will enable a more gradual transition to an end state that relies on rate design elements aligned with cost of service.

3. Tier Differential Amount

The current ratio-based differential was arrived at by the Commission finding that "a 25 (percent) differential (was) 'mild'" and was similar to the tier differentials in place prior to Assembly Bill (AB) 1X.[22] As noted above, there is no cost of service basis for tiered rates, and any level will likely be without strong basis. PG&E therefore proposes a $0.06/kWh differential to balance providing a meaningful decrease to upper tier rates, while retaining an absolute $/kWh tier differential that is approximately equal to that in place at the end of the glide path approved by D.15-07-001. Since this 2015 case concluded differentials slightly less than this level were just and reasonable and compliant with the law, PG&E believes this is an appropriate level to implement at this time.[23] Given that this differential was arrived at in the context of rate design principles that did not even consider the need to balance conservation incentives against beneficial electrification incentives, it can be argued that even this proposed differential is too high.

With this change, all rate changes between GRCs for tiered rates will be done on an equal cents basis.

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22 D.15-07-001, p. 315, Finding of Fact 72.

23 *Id.* at p.326, COL 1 and 2; pp. 327-328, COL 11 and 12.

G. TOU Rates

1. Introduction

Currently, the majority of PG&E's customers take service on a TOU rate due to the transition to E-TOU-C as the default residential rate and increasing interest in optional TOU rates. The following sections describe PG&E's proposals for its various TOU rate options that are planned to remain active tariffs through the end of this proceeding; rates that currently exist but are scheduled to be eliminated are not addressed in this testimony. While PG&E proposes no changes to the TOU period definitions, it proposes to update TOU price differentials to better align these rates with the underlying marginal costs calculated in Exhibit 1. In summary, PG&E proposes to gradually move the TOU differentials of the default rate (E-TOU-C) towards marginal cost-based differentials, and to immediately move all optional rates' differentials to 80 percent of marginal cost.

Other than the proposed changes to differentials, any other changes to generation and distribution rates between GRCs will continue to be done on an equal cents basis.

2. Summary of TOU Period Definitions

PG&E proposes to retain the existing TOU period definitions outlined in Table 3-6 below, which avoids having to introduce structural changes to customers that have become accustomed to the existing TOU periods after significant Marketing, Education, and Outreach campaigns. Instead, customers will only need to understand that the incentive to shift usage from one period to another is increasing.

TABLE 3-6
TOU PERIOD DEFINITIONS BY PG&E RESIDENTIAL RATE

Line No.	Season	TOU Period	E-TOU-C	E-TOU-D	E-ELEC/EV2
1	Summer (June through September)	Peak	4 p.m. – 9 p.m., every day	5 p.m. to 8 p.m., Weekdays Only	4 p.m. – 9 p.m., every day
2		Part-Peak	N/A	N/A	3 p.m. to 4 p.m. and 9 p.m. to 12 a.m., every day
3		Off-Peak	All other hours	All other hours	All other hours
4	Winter (October through May)	Peak	4 p.m. – 9 p.m., every day	5 p.m. to 8 p.m., Weekdays Only	4 p.m. – 9 p.m., every day
5		Part-Peak	N/A	N/A	3 p.m. to 4 p.m. and 9 p.m. to 12 a.m., every day
6		Off-Peak	All other hours	All other hours	All other hours

3. Summary of Marginal Costs Compared to Current and Proposed TOU Differentials

PG&E’s residential marginal cost differentials, and current and proposed TOU price differentials are summarized in Tables 3-7, 3-8, and 3-9 below. For E-TOU-C, the proposed differentials are the end state that is planned to be reached at the end of the 3-year transition period.[24] All other proposed differentials are intended to be implemented as soon as is practicable after a final decision is issued in this proceeding. Differentials for E-TOU-D and E-ELEC are proposed to be increased to 80 percent of the marginal cost differentials, while EV2 is proposed to move distribution differentials closer to marginal cost while setting the generation differentials equal to marginal cost.

Generation rates are differentiated according to Marginal Energy Costs and Marginal Generation Capacity Costs, while distribution costs are differentiated according to Marginal Distribution Capacity Costs – Primary.

[24] Current differentials are as of 7/1/2024, consistent with the present rate basis of this application. However, the E-TOU-C Summer Peak to Off-Peak differential increased by $0.02/kWh in 2025.

TABLE 3-7
COMPARISON OF TOTAL BUNDLED TOU RATE DIFFERENTIALS

			Summer		Winter	
Line No.	Schedule(s)	Scenario	Peak vs. Off	Part vs. Off	Peak vs. Off	Part vs. Off
1	E-TOU-C	Marginal Cost	$0.315	N/A	$0.037	N/A
2		Current	$0.103	N/A	$0.030	N/A
3		Proposed	$0.240	N/A	$0.036	N/A
4		$/kWh Change	$0.137	N/A	$0.006	N/A
5	E-TOU-D	Marginal Cost	$0.407	N/A	$0.046	N/A
6		Current	$0.135	N/A	$0.039	N/A
7		Proposed	$0.326	N/A	$0.046	N/A
8		$/kWh Change	$0.191	N/A	$0.007	N/A
9	EV2	Marginal Cost	$0.332	$0.052	$0.038	$0.006
10		Current	$0.313	$0.202	$0.185	$0.169
11		Proposed	$0.365	$0.136	$0.139	$0.106
12		$/kWh Change	$0.052	$(0.066)	$(0.046)	$(0.063)
13	E-ELEC	Marginal Cost	$0.0.332	$0.052	$0.038	$0.006
14		Current	$0.219	$0.057	$0.036	$0.014
15		Proposed	$0.265	$0.036	$0.039	$0.006
16		$/kWh Change	$0.046	$(0.021)	$(0.003)	$(0.008)

TABLE 3-8
COMPARISON OF GENERATION TOU RATE DIFFERENTIALS

Line No.	Schedule(s)	Scenario	Summer Peak vs. Off	Summer Part vs. Off	Winter Peak vs. Off	Winter Part vs. Off
1	E-TOU-C	Marginal Cost	$0.161	N/A	$0.025	N/A
2		Current	$0.083	N/A	$0.027	N/A
3		Proposed	$0.161	N/A	$0.025	N/A
4	E-TOU-D	Marginal Cost	$0.229	N/A	$0.030	N/A
5		Current	$0.105	N/A	$0.035	N/A
6		Proposed	$0.229	N/A	$0.030	N/A
7	EV2	Marginal Cost	$0.164	$0.010	$0.027	$0.005
8		Current	$0.086	$0.041	$0.036	$0.023
9		Proposed	$0.164	$0.010	$0.027	$0.005
10	E-ELEC	Marginal Cost	$0.164	$0.010	$0.027	$0.005
11		Current	$0.144	$0.045	$0.033	$0.013
12		Proposed	$0.164	$0.010	$0.027	$0.005

TABLE 3-9
COMPARISON OF DISTRIBUTION TOU RATE DIFFERENTIALS

Line No.	Schedule(s)	Scenario	Summer Peak vs. Off	Summer Part vs. Off	Winter Peak vs. Off	Winter Part vs. Off
1	E-TOU-C	Marginal Cost	$0.154	N/A	$0.011	N/A
2		Current	$0.020	N/A	$0.003	N/A
3		Proposed	$0.079	N/A	$0.011	N/A
4	E-TOU-D	Marginal Cost	$0.178	N/A	$0.016	N/A
5		Current	$0.030	N/A	$0.004	N/A
6		Proposed	$0.097	N/A	$0.016	N/A
7	EV2	Marginal Cost	$0.167	$0.042	$0.012	$0.001
8		Current	$0.227	$0.161	$0.149	$0.145
9		Proposed	$0.201	$0.126	$0.112	$0.101
10	E-ELEC	Marginal Cost	$0.167	$0.042	$0.012	$0.001
11		Current	$0.074	$0.012	$0.003	$0.001
12		Proposed	$0.101	$0.026	$0.012	$0.001

4. Default Schedule E-TOU-C

Schedule E-TOU-C is now PG&E's default rate schedule; its original design as approved in D.19.07-004 was intentionally set to be "TOU Lite" so as to ease the transition of customers onto the default TOU rate and increase the likelihood of customers remaining on the rate after the bill protection period ended.[25] Specifically, the CPUC adopted PG&E's proposal for a summer Peak vs. Off-Peak Price (POPP) differential of 6.3 cents per kWh and a winter POPP of 1.7 cents per kWh.[26] In 2021, the CPUC adopted a settlement agreement to increase these differentials over time to $0.123/kWh in the summer and $0.03/kWh in the winter.[27] Currently, these differentials are $0.103/kWh for summer and $0.03/kWh for winter, and PG&E will complete this transition on June 1, 2025.

Per analysis in Exhibit (PG&E-1), the cost-based differentials for the E-TOU-C TOU period definitions are now $0.315/kWh and $0.037/kWh in the summer and winter, respectively. Given the status of E-TOU-C as the default rate, we do not propose to move all the way to these marginal cost levels immediately. We instead propose to move towards the marginal cost differential by gradually increasing the summer peak to off-peak differential over three years, starting in 2027 if a final decision is issued approving this proposal in time. Otherwise, this schedule would be pushed forward one year. This is shown in more detail in Table 3-10 below.

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25 Per D.19-07-004, p. 219, OP 29. During the transition period, customers who would have had a lower bill on the non-TOU rate were refunded the difference at the end of their first year on TOU.

26 D.19-07-004, p. 201, COL 33.

27 D.21-11-016, p. 107.

TABLE 3-10
PLANNED AND PROPOSED E-TOU-C DIFFERENTIAL TRANSITION PATH

Line No.	Year	Generation Differential	Distribution Differential	Total Differential	Annual Increase
1	2024	$0.083	$0.020	$0.103	$0.020
2	2025	$0.103	$0.020	$0.123	$0.020
3	2026	$0.103	$0.020	$0.123	$0.000
4	2027	$0.123	$0.040	$0.163	$0.040
5	2028	$0.143	$0.060	$0.203	$0.040
6	2029	$0.161	$0.079	$0.240	$0.037

These changes balance the priority identified in the DFOIR to increase default rate TOU differentials against moderating bill impacts for customers. Due to the large number of customers taking service on E-TOU-C and its history as a “TOU-lite” rate, PG&E believes it prudent to gradually move towards marginal costs. This proposed trajectory will result in the summer on-peak to off-peak differential reaching 76 percent of the marginal cost level. At the component level, generation rates will reach the full marginal cost basis, while distribution rates will only reach a portion of the estimated marginal cost basis. This reasonably balances moving the default rate towards marginal cost against the need to maintain customer acceptance of the rate. This proposal increases the differential by twice as much per year as the adopted 2020 GRC Phase II Settlement Agreement. Moving more rapidly could risk customer acceptance of this rate. In its next GRC Phase II application, PG&E will consider whether revised marginal costs and customer feedback justify further changes to E-TOU-C.

5. Optional TOU Schedules

PG&E’s optional time-of-use rates (E-TOU-D, E-ELEC, and EV2) already feature more significant differentials than E-TOU-C. While each rate serves different niches, all are designed to provide more cost-based price signals to customers than the default rate. However, all are proposed to be designed on a revenue neutral basis to E-TOU-C.

While PG&E proposes a gradual transition towards marginal cost-based differentials for E-TOU-C, adjustments to PG&E’s optional time-of-use rates are proposed to be implemented in a single step. Specifically, PG&E proposes to set the TOU differentials for Schedules E-TOU-D and E-ELEC at 80 percent of the marginal cost differentials upon initial implementation of the rate design changes approved in this decision. PG&E does not propose an immediate transition to marginal cost, to manage customer acceptance of changes to these optional rates. As with E-TOU-C, the generation component of these rates will transition to the marginal cost differential, while distribution rate differentials remaining less than the marginal cost differential. This update will maintain both E-TOU-D and E-ELEC as reasonable options for customers to take service on TOU rates with cost-based differentials. Since E-TOU-D has a more narrow peak period definition than PG&E's other residential rate schedules, it has higher peak rates than other rate schedules.

If the same changes were made to EV2, it would be identical to E-ELEC, as both would have the same TOU period definitions, TOU differentials, and fixed charges. Therefore, to maintain EV2's niche as a rate with artificially high TOU differentials to incent off peak EV charging more than other rates, we propose to set the rate's generation differentials at marginal cost levels (reflecting an increase from the status quo), while making adjustments to the rate's distribution differentials to move closer to marginal cost. Specifically, the new starting point for distribution differentials remains the same as the proposed E-ELEC differentials, but these differentials are increased by $0.10/kWh across the board, compared to approximately $0.15/kWh in today's rates. This results in this differential adder being reduced by about one third. The overall result of these changes is to more directly base the differentials on marginal cost, while (approximately) retaining existing off-peak rates for EV charging. Table 3-11 shows the proposed differentials to EV2 in more detail.

TABLE 3-11
EV2 PROPOSED DIFFERENTIALS COMPARED TO PRESENT AND MARGINAL COSTS

			Summer		Winter	
Line No.	Cost Category	Scenario	Peak vs. Off	Part vs. Off	Peak vs. Off	Part vs. Off
1	Generation	Marginal Cost	$0.164	$0.010	$0.027	$0.005
2		Current	$0.086	$0.041	$0.036	$0.023
3		Proposed	$0.164	$0.010	$0.027	$0.005
4		Change vs. Present	$0.078	$(0.031)	$(0.009))	$(0.018)
5		Deviation vs. MC	$(0.000)	$0.000	$0.000	$(0.000)
6	Distribution	Marginal Cost	$0.167	$0.042	$0.012	$0.0.001
7		Current	$0.227	$0.161	$0.149	$0.145
8		Proposed	$0.201	$0.126	$0.112	$0.101
9		Change vs. Present	$(0.026	(0.035)	$(0.037	$(0.044
10		Deviation vs. MC	$0.034	$0.084	$0.100	$0.100
11	Total	Marginal Cost	$0.332	$0.052	$0.038	$0.006
12		Current	$0.313	$0.202	$0.185	$0.169
13		Proposed	$0.365	$0.136	$0.139	$0.106
14		Change vs. Present	$0.052	$(0.066)	$(0.046)	$(0.063)
15		Deviation vs. MC	$0.033	$0.084	$0.101	$0.100

6. Schedule EV2 Baseline Quantity Limits

In addition to the changes proposed to the EV2 TOU differentials outlined above, PG&E proposes to eliminate the requirement that EV2 customers use less than 800 percent of their baseline quantity to remain eligible for this rate.

This requirement was adopted through a settlement agreement in PG&E's 2017 GRC II proceeding as a replacement for the previous restriction on the total number of customers enrolled on EV rates. While EV2 does retain TOU differentials that exceed marginal cost, PG&E believes the technology requirements alone are an appropriate measure to limit the applicability of the rate, rather than firm limits on customer usage. Given that the two other un-tiered TOU rates have no customer size limits, there is little reason to maintain this restriction. This will prevent the confusing scenario where customers adopting the technologies this rate promotes are removed from the rate if they adopt too many of these technologies.

Therefore, eliminating the 800 percent of baseline requirement will improve customer experience.

H. SmartRate: Eliminating Minimum Number of SmartDay Events Requirement (Witness: Natalie Yang)

Pursuant to D.06-07-027,[28] PG&E offers the Critical Peak Pricing (CPP) rate programs which include Peak Day Pricing for non-residential customers and SmartRate for residential customers. SmartRate is a voluntary rate supplement to the customer's applicable rate schedule[29] and is available to PG&E's bundled-service customers served on single family residential electric rate schedules. A SmartDay is called on especially hot days (typically 98 degrees Fahrenheit (ºF) on non-holiday weekdays and 105ºF on holidays and weekends) when demand for California's electricity resources peak. A minimum of nine and a maximum of 15 SmartDays may be called in any calendar year. SmartRate customers earn credits[30] during bill periods where at least one SmartDay event occurs[31] and pay a higher rate[32] during 4 p.m. to 9 p.m. on a Smart Day. By voluntarily remaining on the program beyond the bill protection period, customers will pay a higher rate between 4 p.m. and 9 p.m. on SmartDays and their bill may be higher than their regular rate plan. However, they may be able to save money if curtail sufficient usage during SmartDay Hours on those Smart Days. PG&E proposes to only eliminate the minimum number of SmartDay program requirement and not make any changes to the SmartRate rate structure.

On May 1, 2015, the Commission approved AL 4627-E, authorizing PG&E to modify the program design for SmartRate with a minimum of nine and a

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28 D.06-07-027, OP 3.

29 PG&E SmartRate, available at: <https://www.pge.com/en/account/rate-plans/find-your-best-rate-plan/smartrate.html> (accessed Sept. 11, 2024).

30 SmartRate participants receive a SmartRate Non-High Price credit ($0.00636 per kWh) and a SmartRate Participation Credit ($0.00167 per kWh) for usage other than 4 p.m. to 9 p.m. during SmartDay and all usage on those days within a bill period that are not declared as SmartDays.

31 The SmartRate Participation and Program credits are multiplied by the number of SmartDays in a bill period.

32 SmartRate participants are charged $0.60 in addition to their regular rate charges for each kWh on all usage between 4 p.m. and 9 p.m. on each SmartDay.

maximum of 15 SmartDay events and a revenue neutral design basis of 12 events.[33] Subsequently in 2019, the Commission adopted the SmartRate Rate Design Revisions modifying the program's rate design structure so that credits are only provided in months when SmartDay events are called,[34] in response to customer feedback that the bill was not reflecting effort (e.g., in some years there would be a low number of events and high bill savings, and other years a high number of events and lower bill savings). This change in the program design also had the benefit of making SmartRate revenue neutral regardless of the number of SmartDay events called. Therefore, the minimum event day requirement is unnecessary in maintaining revenue neutrality.

The minimum nine-event requirement has also led to customer confusion when PG&E needed to call events, despite not meeting the weather temperature threshold, just to be able to meet this requirement. For example, in summer of 2023, the weather in PG&E territory was relatively mild and PG&E did not meet the SmartRate weather threshold required to be able to meet the minimum 9-event requirement. Therefore, to meet the minimum event day requirement, on September 26, 2023, PG&E utilized the minimum dispatch clause in its SmartRate Tariff[35] and called the last SmartRate event to close the season with nine events.

PG&E strongly believes that eliminating the minimum event requirement will eliminate customer confusion and ensure program effectiveness. Furthermore, removing a minimum event criterion will ensure that events are driven by temperature conditions and actual system demand response needs, which better align with the program's intended purpose.

I. Minimum Bill Revisions (Witness: Joseph Au)

In light of the Residential Fixed Charge implementation in Q1 2026, pursuant to D.24-05-028, the minimum bill revisions for PG&E's residential rates

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33 D.14-06-037, p. 12; p. 24, FOF 8.

34 D.19-07-004, p. 203, COL 49 and 50; p. 215, OP 20.

35 "SmartDay events may also be initiated as warranted on a day-ahead basis by…3) to meet annual SmartDay Event Day limits for a calendar year….", Electric Schedule E-RSMART, Sheet 4, Notification and Trigger, available at: <https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_E-RSMART.pdf> (accessed Sept. 11, 2024).

and programs (CARE, FERA, Medical Baseline) pursuant to D.21-11-016 and D.20-03-003 are no longer applicable.[36]

On May 15, 2024, the CPUC issued D.24-05-028 authorizing all investor-owned electric utilities to change the structure of residential customer bills in accordance with AB 205, Stats. 2022, Ch. 61 (AB 205). This charge, otherwise known as an IGFC, alters the structure of residential customer bills by shifting the recovery of a portion of fixed costs from volumetric rates to a separate, fixed amount on bills without changing the total costs that utilities may recover from customers.[37] On August 13, 2024, PG&E submitted its Tier 3 Advice Letter (AL) 7351-E regarding its Fixed Charge implementation plan and is awaiting Commission Resolution.[38]

The CPUC also authorized the elimination of the minimum bill at the same time the Fixed Charge is implemented. Therefore, previously adopted minimum bill revisions pursuant to other proceedings should not be implemented. PG&E requests that the CPUC remove the requirements to implement the following minimum bill-related revisions as these requirements are now moot:

1) Calculating minimum bill amounts on the basis of distribution and Conservation Incentive Adjustment/Total Rate Adjustment Component charges.[39]
2) Implementation of the following changes to the minimum bill when it was practicable to do so:[40]

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36 D.24-05-028, Attachment C, p. 9, “Rate Design: (Income Graduated Fixed Charges) IGFCs will consist of two components, (1) a base revenue fixed charge, and (2) adjustment schedules that will be converted from volumetric rates to a fixed monthly charge.”

37 D.24-05-028.

38 Pursuant to D.24-05-028 PG&E filed AL 7351-E on August 13, 2024 outlining its plans to implement Residential Fixed Charge in March 2026.

39 D.20-03-003, pp. 50-51, OP 5. Cal Advocates proposed to calculate the minimum bill solely on distribution rates, and allow non-bypassable charges such as PPP and transmission charges to be assessed based solely on usage, as it would improve equity by ensuring that very low usage customers do not pay more in non-bypassable charges for certain costs than contemplated by the Commission or the Legislature.

40 D.21-11-016, p. 168, OP 16, “Pacific Gas and Electric shall implement the provisions of the residential rate design settlement as soon as practicable.”

a) Elimination of a separate minimum bill amount for CARE customers to facilitate the application of a single 35 percent discount for each CARE customer;[41]

b) Elimination of a separate minimum bill amount for FERA customers to facilitate the application of a single 18 percent discount for each FERA customer;[42]

c) Increasing the minimum bill for medical baseline customers to $10;[43]

d) Elimination of the current 50 percent discount on the Delivery Minimum Bill Amount for customers on PG&E's FERA program and providing 18 percent line-item discount to all FERA customers on Schedule E-FERA regardless of their usage level;[44] and

e) Elimination of the current 50 percent discount on the Delivery Minimum Bill Amount for customers on PG&E's Medical Baseline Program.[45]

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41 D.21-11-016, p. 101, "No party contested PG&E's proposals, and this decision therefore finds that PG&E's proposals for elimination of a separate minimum bill amount for CARE customers to facilitate the application of a single 35 percent discount and for elimination of a separate minimum bill amount for FERA customers to facilitate the application of a single 18 percent discount are reasonable and should be adopted."

42 *Id.*

43 D.21-11-016, p. 102, "No party contested PG&E's proposal, and this decision therefore finds that PG&E's proposal to increase the minimum bill for medical baseline customers to $10 is reasonable and should be adopted, given that it harmonizes the minimum bill amount across all of PG&E's residential rate schedules and is expected to have negligible bill impacts on medical baseline customers due to the relatively high usage exhibited by those customers."

44 A.19-11-019, PG&E's Motion for Adoption of Residential Rate Design Supplemental Settlement Agreement, Attachment 1, p. 8, approved in D.21-11-016, "The RRD Settling Parties agree that the current 50 percent discount on the Delivery Minimum Bill Amount for customers on PG&E's FERA Program shall be eliminated, as proposed by PG&E. Instead, all FERA customers will receive an 18 percent line-item discount on Schedule E-FERA regardless of their usage level."

45 A.19-11-019, PG&E's Motion for Adoption of Residential Rate Design Supplemental Settlement Agreement, Attachment 1, pp. 8-9, approved in D.21-11-016, "The RRD Settling Parties agree that the current 50 percent discount on the Delivery Minimum Bill Amount for customers on PG&E's Medical Baseline Program shall be eliminated, as proposed by PG&E. Medical Baseline customers on tiered rates will continue to pay discounted bills by receiving additional baseline allocations that allow them to consume additional kWh at the lower Tier 1 rate."

J. Master Meter Discounts (Witness: Hugh Krogh-Freeman)

This section presents PG&E's electric MMD proposals for Electric Multi-Family Service (Schedule ES) and Electric Mobile Home Park Service (Schedule ET). Under both rate schedules, electricity is delivered to a single master meter at a residential development. Under Schedule ET, the electricity is delivered through a private sub-metered distribution system to individual tenants within the MMMHP. Under Schedule ES, electricity is delivered to master-metered, multi-family residential dwellings. PG&E's end-use customers on the master meter schedules are owners of MMMHPs and other master-metered multi-family residential developments such as apartment buildings or apartment complexes. The owners who get their service from PG&E under these master meter rate schedules receive a discount to compensate them for utility–avoided costs because the Utility does not directly serve their tenants. These rate schedules have been closed to new customers since January 1, 1997.

A summary of PG&E's Master Meter proposal is presented in Table 3-1 in Section B, above. The MMD methodology proposed in this application follows the methodology adopted in D.18-08-013.[46] Figure 3-2 below shows a typical master-metered arrangement and applies to both MHPs and multi-family dwellings.

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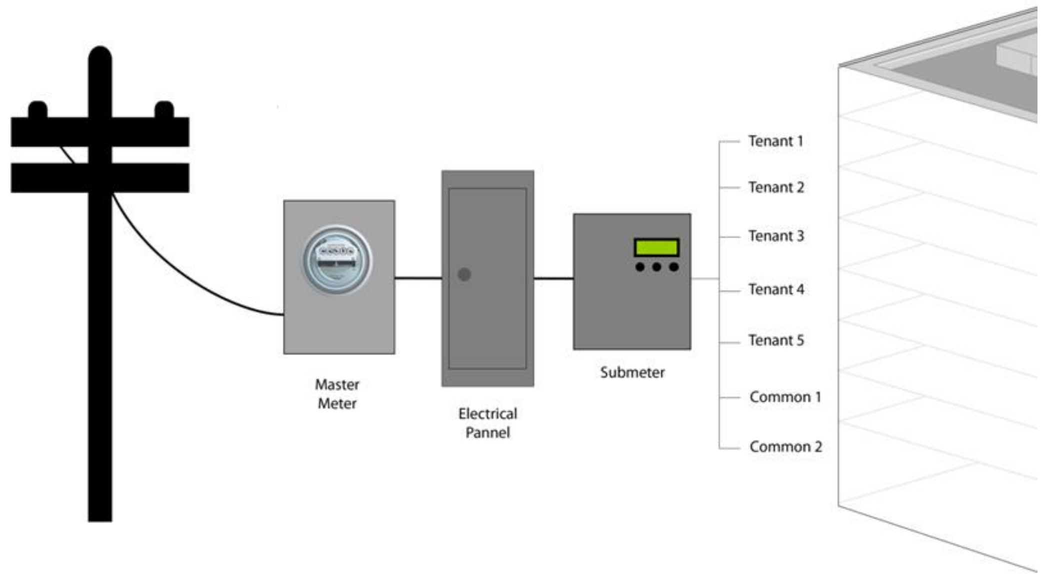
[46] D.18-08-013, p. 187.

FIGURE 3-1
MASTER-METERED SCENARIO



1. Background

a. History

In D.11-12-053, its decision for the 2011 GRC II, the Commission adopted PG&E's proposed marginal cost-based approach for calculating the MMD.[47] In D.18-08-013 for PG&E's 2017 GRC II,[48] the Commission writes:

> This methodology for calculating the master meter discount was used in the last Commission decision to consider these issues in depth—D.11-12-053—and we adopt it in this decision as well.

In this proceeding, PG&E proposes to use the same methodology adopted by the CPUC in D.18-08-013 and D.21-11-016.

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47 "The majority of PG&E's residential rate design issues were decided in D.11-05-047. The three remaining residential issues are: (1) natural gas baseline quantities; (2) Schedule ES multifamily master meter discount; and (3) Schedule ET mobile home master meter discount. The first two of these issues were addressed in an all-party settlement, as discussed below. The Schedule ET discount was contested…." (D.11-12-053, p. 33) and decides, "Pacific Gas and Electric Company's transformer costs, at secondary voltage, for Mobile Home Park master meter connections are adopted for purposes of the Schedule ET discount calculations" *(Id.* at p. 92, OP 22).

48 D.18-08-013, p. 114.

The following formula captures the methodology. The terms in the formula are explained below.

(MMD) = (base discount) – (DBA) + (line loss adjustment)

b. Base Discount

The base discount represents the costs of transformers, service conductors, service drops, and meters that PG&E avoids in a master metered arrangement. The amount of the discount differs between ET and ES, because a master-metered arrangement (in which PG&E does not serve each individual dwelling) results in different cost savings for PG&E, depending on whether a master meter is used for a MHP or a multi-family dwelling. PG&E avoids the following costs under a master-metered arrangement for MHPs (ET), but not in a master-metered arrangement for multi-family dwellings (ES):

1) Transformer equipment costs;
2) Service equipment costs;
3) Transformer operations and maintenance costs;
4) Service operations and maintenance costs;
5) Secondary distribution capacity costs; and
6) Line loss costs.

Avoided costs not listed above are the same for the two schedules.

A MHP owner incurs his or her own cost of constructing transformers and services to extend electric service from the master meter to the submeters, alleviating PG&E's cost. However, in a multi-family dwelling eligible for Schedule ES, all submeters are clustered in one large "bank" so the owner of the multi-family dwelling does not construct transformers and service drops to extend electric distribution from the master meter to the submeters. Instead, PG&E does. Therefore, PG&E saves no transformer and service costs in a master-metered arrangement for multi-family dwellings.

c. Line Loss Adjustment

"Line loss" refers to energy lost in the form of heat from a power line, due to electrical resistance, capacitance, or inductance. The line loss adjustment increases the amount of the discount for MHP (ET) owners. This adjustment accounts for the fact that the park owners must purchase more electricity at the master meter than the total electricity the tenants demand at their individual submeters. Additional power is needed because some power is lost in the lines between the master meter and the submeters.

The calculation of the line loss adjustment requires the following quantities:

- Capacity Loss Adjustment Factor: The proportion of energy lost due to line losses between the master meter and the submeters.
- Average Loss per Residential Unit: The average usage per residential unit multiplied by the Capacity Loss Adjustment Factor.
- Weighted Average Price per kWh: Calculated by multiplying the $/kWh price in each tier by the average monthly usage in that tier and then dividing by the sum of the average monthly usage in all tiers.

The line loss adjustment is calculated by multiplying the average loss per residential unit by the weighted average price per kWh.

For example, suppose the sub-metered tenants wish to purchase a total of 95 kWh of electricity from PG&E. Suppose further that the Capacity Loss Adjustment Factor is 5 percent, and the weighted average price per kWh is $0.50 / kWh. The owner must purchase more than 95 kWh to serve these customers, because some electricity gets lost in transit between the master meter and the tenant meters. If the owner purchases 100 kWh, then 100 * (1.00 - 0.05) = 95 kWh are transmitted to tenants with 5 kWh lost through heat ("Average loss per Residential Unit"). The line loss adjustment compensates the owner for the lost 5 kWh at $0.50 / kWh = 5 kWh * $0.50 / kWh = $2.50.

The DBA decreases the MMD. The MHP owner receives a full baseline allowance for each of the sub-metered dwellings, even though some dwellings use less than the baseline allowance. If the DBA did not exist, the owner would face an artificially low rate for electricity because his or her baseline quantity would be too high, and therefore an excessive amount of usage would fall into lower tiers. The DBA will be discussed in detail in the next section.

2. Proposed MMDs

Table 3-12 below shows the PG&E's present and proposed MMDs for Schedules ET and ES, including components of the net discount: the base discount, the Line Loss Adjustment (LLA) (discussed in this section), and the DBA (discussed in Section K below).[49] These discounts are directly based on the costs avoided by PG&E.

TABLE 3-12
PROPOSED MASTER-METERED DISCOUNTS

		Proposed				Current
Line No.	Rate Schedule	Base Discount (Component)	DBA (Component)	Line Loss Adjustment (Component)	Net Discount[(a)]	Net Discount
1	ET (MHP Service)	$3.45	$5.48	$3.68	$1.65	$3.54
2	ES (Multi-Family Service)	$2.58	$3.18	N/A	–	$0.82

(a) The net discount output by the model for the ES rate schedule was $(0.58).

K. DBA (Witness: Annette Taylor)

1. Introduction

This section presents the methodology and resulting estimates of DBA, which is a component of the MMD as described in Section L above. As described below, the complete DBA applies to Schedule E-1T (non-CARE) or E-1TL (CARE) for mobile home parks and a portion of the DBA applies to Schedules E-1S & E-1SR (non-CARE) or Schedules E-1SL & E-1SRL (CARE) for multi-family properties. For the rest of this section, the mobile home parks rate schedules will be referred to as ET and the multi-family properties will be referred to as ES.

As explained above, without the DBA, mobile park homeowners would get a bigger deduction on their bills than is warranted. Therefore, PG&E uses the baseline DBA to reduce the discount the MHP operators would

49 The LLA adds to the base discount to compensate the master meter customer for usage at the master meter that is lost when distributed to the tenant spaces.

otherwise receive by billing sub-metered tenants at higher prices or tiers than PG&E bills the park operator at the central master meter level.

PG&E proposes a DBA of $5.48 per space per month for MHP rate schedules, ET and a DBA of $3.18 for multi-family dwellings rate schedules, ES. As Table 3-1 shows, in this GRC II, PG&E continues to use the Commission adopted DBA methodology as used in the 2020 GRC II. The DBA was calculated using 2022-2023 usage data and the 2023 GRC II proposed rates.

In addition, PG&E discusses the Commission's MMDs compliance items from D.21-11-016 regarding recalculating the DBA and LLA after the removal of the High Usage Charge (HUC) from the rate calculations or when the new fixed charge has been implemented.

A summary of PG&E's DBA proposal is presented in Table 3-1 in Section B, above.

2. Background

The baseline diversity effect is caused by the difference in kWh billed at different tiered prices at the master meter and the individual submeters. The baseline diversity effect is different for property owners under ET and ES since mobile park and multi-family property owners provide different services to their tenants. MHP owners provide transformers, service drops, meters, and other customer services such billing and meter reading to their tenants while multi-family property owners provide the same services except for transformers and service drops.

Under Schedule ET, the usage at the master meter receives one baseline allowance per tenant. In turn, the park operator generally bills sub-metered tenants on Schedule E-1.[50] Consequently, in a park with two tenants, if one tenant is well under baseline, and the other tenant is slightly above baseline, all master meter kWh usage will be billed at the lower baseline Tier 1 rate by PG&E, while the sub-metered second tenant will be billed by the park operator for Tier 2 usage. This means the park operator, in the aggregate, would be charging a higher dollar amount to his

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50 E-1 rate schedule is applicable to residential service in single-family dwellings and in flats and apartments separately metered by PG&E.

tenants than is being charged to the park operator by PG&E at the master meter. The baseline diversity adjustment amount is intended to mitigate this excess on an average basis across all submetered MHPs.

3. DBA Methodology

The DBA calculation for one MHP is given below. First, a yearly average tenant bill is calculated by dividing the sum of all of the monthly tenants' bills for that year by the (number of tenants x 12 months). Then a yearly average master meter bill per tenant is calculated by dividing the monthly master meter bills for that year by (number of tenants x 12 months). Lastly, the average tenant bill is subtracted from the average master meter bill per tenant to get the DBA. Figure 3-2 shows an example of this calculation.

FIGURE 3-2
DBA FORMULA

$$Diversity\ Benefit\ Adjustment = \frac{(\sum Direct\ Bills - \sum ET\ Bills)}{Number\ of\ tenants\ months}$$

- *<u>Direct Bills</u>: Sum of the monthly bills of all tenants in one year*
- *<u>ET Bills</u>: Sum of the monthly Master Meter Bills in one year*
- *<u>Number of tenants months</u>: Number of tenants X 12*

As stated in Section L, the majority of MHPs are master-metered by PG&E and served on Schedule ET, with park operators performing all tenant metering and billing functions through the use of an operator installed, maintained, and administered distribution submetering system. As of December 2023, there were approximately 1,200 MHPs served on Schedule ET and 500 multi-family properties under Schedule ET.

Tenants in master meter mobile home parks are not considered PG&E customers. Consequently, PG&E does not have access to sub-metered tenant billing data in master-metered parks. Therefore, to model sub-metered tenant usage in Schedule ET parks, PG&E uses a sample of directly served MHPs as a proxy for the sub-metered MHPs. More specifically, for the 2023 GRC II DBA proposal, PG&E used a sample of 189 directly served MHPs to represent submeter MHPs.[51] These directly served parks are generally served on Residential rate Schedules E-1 and E-11L, for Non-CARE and CARE tenants, respectively. In addition, tenants with NEM accounts are removed from both the sample and the ET mobile home park population.

To compute the difference calculation the following steps are performed. First, a bill based on either the E-1 or the E-1 CARE rate is calculated for each of the individual tenant bills in the directly served sample representing the simulated sum of sub-metered bills. Second, the individual directly served bills were used to create a synthesized ET bill for the entire park. For each park, PG&E calculates the difference between the average tenant bill and average master meter bill per tenant. Table 3-13 shows an illustrative example of this calculation. The average bill for a tenant in this park which has 30 units is $205 while the average park bill is $200 per tenant. The difference in what the park pays per average tenant, and the average tenant is five dollars. PG&E repeats this calculation for each park in the directly served sample.

TABLE 3-13
ILLUSTRATIVE EXAMPLE OF DIFFERENCE CALCULATION

Line No.	Park ID	Climate	Care Participation	kWh Range	Tenant kWh	Avg Park bill	Avg Tenant Bill	Difference	Actual Spaces
1	A23	Desert	Over 70%	Over 400	450	$200	$205	$5	30

Note:

- Difference = Avg Tenant Bill – Avg Park Bill.
- Data source = Rate Data Analytic Team.

The directly metered sample is smaller than the master metered mobile home park population which consist of approximately 1200 parks as of December 2023. Therefore, PG&E stratifies both the directly metered sample and the master metered mobile park population. This means PG&E

[51] PG&E use the same sample of master meter use in the 2020 GRC II then removed the parks that have become directly served and are no longer master metered to get the updated sample of 189.

divides the sample and population into shared attributes or characteristics. This is used to correct the size imbalance between the sample and the population. For this 2023 GRC II, PG&E stratified the two datasets as follows:

1) <u>Climate Zone</u>: Coast, Desert, Hills, and Valley;
2) <u>Care Participation</u>: Under or Over 70 percent; and
3) <u>Tenant Usage</u>: Under or Over 400 kWh.

Each park in the directly metered parks and the master metered MHPs are assigned to: (1) one of the climate zones, (2) CARE participation, and (3) tenant usage categories. For example, the directly metered park in Table 3-13 is: (1) located in a desert region, (2) with over 70 percent of the park's tenants participating in CARE Program, and (3) the average usage for the tenants being over 400 kWh. Table 3-14 shows an illustrative example where a MHP can be put into 13 unique strata or groups. On line 1, the first strata, the Sample Count shows there are 15 directly served parks. Each of these parks are in the coastal region where CARE participation is under 70 percent and the average tenant usage is under 400 kWh. In addition, 90 master meter MHPs, shown in the MHP Count column, are in the first strata. For each strata, the average difference between what a tenant pays and what the park owner is charge per tenant for the sample population is calculated in Average Difference column. For instance, the average difference for the first strata is $6.20.

TABLE 3-14
ILLUSTRATIVE EXAMPLE OF DBA CALCULATION

Line No.	Climate	CARE Participation	Tenant Use	Average Difference	Sample Count	MHP Count	Difference Weighted
1	COAST	1	1	$6.20	15	90	$557.96
2	COAST	2	1	$4.44	3	18	$79.85
3	DESERT	1	1	$2.39	22	132	$315.43
4	DESERT	1	2	$2.79	16	96	$267.65
5	DESERT	2	1	$4.95	4	24	$118.71
6	DESERT	2	2	$5.70	14	84	$478.87
7	HILLS	1	1	$6.95	6	36	$250.31
8	HILLS	1	2	$5.32	17	102	$543.09
9	HILLS	2	1	$5.59	27	162	$906.18
10	VALLEY	1	1	$7.62	17	102	$777.17
11	VALLEY	1	2	$7.00	19	114	$798.43
12	VALLEY	2	1	$9.98	17	102	$1,017.89
13	VALLEY	2	2	$9.69	23	138	$1,336.85
14		1= under 70%	1=0-400 kWh		200	1,200	$7,448
15		2= over 70%	2=>400		FINAL DBA = $7,448/1200=$6.21		

The DBA for the ET MHP population is calculated by first determining the weighted difference, which is calculated by multiplying the MHP Count by the Average Difference. The final ET DBA, $6.21, is calculated by summing up the Weighted Difference in all strata and dividing by the total ET population.

ET DBA = $7,448/1200 = $6.21

Once PG&E determines the DBA for ET, PG&E uses a ratio of 58 percent to determine the DBA for ES. The 58 percentage is based on values calculated from random samples of MHPs and multi-family apartment buildings in the 2003 GRC II, which was the basis for the 58 percent ratio adopted in D.11-12-053,[52] D.15-08-005,[53] and D.18-08-013.[54] The final ES DBA is $3.60.

[52] D.11-12-053, pp. 33-34, 36.

[53] D.15-08-005, p. 10, Section 7.1.2; A.13-04-012, Residential Rate Design Supplemental Settlement Agreement, pp 3, 5-6, approved in D.15-08-005.

[54] D.18-08-013, pp. 139-140.

ES DBA = 0.58 x ET DBA = $3.60

4. Compliance Items from D.21-11-016

This section describes PG&E's compliance with requirements stemming from D.21-11-016.

a. Rerun DBA and LLA After Implementation of Changes to the Residential High Usage Rates

The Commission directed PG&E to re-run the DBA and LLA after the removal of the HUC from residential rates pursuant to D.21-03-003.[55] PG&E removed the HUC and then PG&E updated the Master Meter DBA and LLA during the 2023 Annual Electric True-Up that went into effect on January 1,2023.[56]

b. Reflect Implementation of the Residential Fixed Charge

The 2020 GRC Residential Rate Design settlements provided that if any residential fixed customer charge might be implemented on Schedule E-1, then PG&E will also rerun the DBA and LLA to account for the associated changes in energy charges and for any associated change to the then-effective residential delivery minimum bill.[57] PG&E plans to implement a fixed charge for residential customers in the first quarter 2026.[58] As directed by AB 205, PG&E and other investor-owned utilities are instructed to change the structure of residential customer bills by shifting the recovery of a portion of fixed costs from volumetric rates to a fixed amount on bills without changing the total costs that utilities may recover from customers.[59] Once the fixed charge is implemented, then PG&E will re-run the DBA and the LLA.

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55 D.21-11.016, pp 121-122.

56 These updates are described in AL 6805-E, p. 12.

57 A.19-11-019, PG&E's Motion for Adoption of Residential Rate Design Supplemental Settlement Agreement, p. 13, approved in D.21-11-016.

58 D.24-05-028, p. 3.

59 D.24-05-028, p .2.

L. Master Meter Discount Calculations (Witness: Hugh Krogh-Freeman)

Tables 3-15 and 3-16 show detailed calculations for the ET and ES MMDs.

TABLE 3-15
SCHEDULE ET – MMDs

Line No.	Schedule ET Master Meter Discount	Costs for Tenant Meter	Costs for Master Meter[a]
1	Transformer	$54.94	$12,820.82
2	Service	$447.69	$18,229.57
3	Meter	$226.93	$2,223.19
4	Transformer/Service/Meter (TSM) Equip. Cost	$729.56	$33,273.58
5	RECC	8.24%	8.24%
6	Annualized Connection Equipment Cost — Finance, Tax, Ins. & Depr.	$60.11	$2,741.67
7	Test Year Secondary Dist. ($/kW-Yr)	$2.59	–
8	Test Year Ongoing Costs Per Residential Unit	–	–
9	Meter Services	$6.04	$13.14
10	Transformer Maintenance	$0.02	$5.75
11	Service Maintenance	$3.57	$145.30
12	Meter Reading	$1.82	$3.30
13	Billing & Payments	$9.24	$10.40
14	Credit & Collections and Account Setup	$1.54	$5.29
15	Total Ongoing Costs Per Residential Unit	$22.23	$183.18
16	Total Connection Cost	$84. 84.94	$2,924.85
17	Average Number of Residential Units	–	67
18	Master Meter Connection Cost Per Residential Unit	–	$43.65
19	Net Marginal Connection Cost Per Residential Unit	$41.28	–
20	Uncollectibles Factor	0.3000%	–
21	Uncollectibles	$0.12	–
22	Net Base Discount Per Residential Unit — Annual	$41.41	–
23	Base Master Meter Discount Per Residential Unit — Monthly	$3.45	–
24	Diversity Benefit Adjustment (Illustrative)	$5.48	–
25	Line Loss Adjustment	$3.68	–
26	Net Discount (Monthly) (Illustrative)	$1.65	–
27	Net Discount (Daily) (Illustrative)	$0.05436	–
28	Base Discount Daily Rate (Illustrative)	$0.11336	–
29	LLA, Daily Rate (Illustrative)	$0.12087	–

(a) Master Meter costs use ML&P S proxy meter for connection and SL&P proxy meter for ongoing costs

TABLE 3-16
SCHEDULE ES – MMDS

Line No.	Schedule ES Master Meter Discount	Costs for Tenant Meter	Costs for Master Meter[a]
1	Transformer	–	–
2	Service	–	–
3	Meter	226.93	2,223.19
4	Transformer/Service/Meter (TSM) Equip. Cost	$226.93	$2,223.19
5	RECC	8.24%	8.24%
6	Annualized Connection Equipment Cost — Finance, Tax, Ins. & Depr.	$18.70	$183.19
7	Test Year Secondary Dist. ($/kW-Yr)	–	–
8	Test Year Ongoing Costs Per Residential Unit	–	–
9	Meter Services	$6.04	$13.14
10	Transformer Maintenance	$0.00	–
11	Service Maintenance	$0.00	–
12	Meter Reading	$1.82	3.30
13	Billing & Collections	$9.24	10.40
14	Credit & Collections and Account Setup	$1.54	5.29
15	Total Ongoing Costs Per Residential Unit	$18.64	$32.13
16	Total Connection Cost	$33	$215.32
17	Average Number of Residential Units	–	34
18	Master Meter Connection Cost Per Residential Unit	–	$6.33
19	Net Marginal Connection Cost Per Residential Unit	$31.00	–
20	Uncollectibles Factor	0.30%	–
21	Uncollectibles	0.09	–
22	Net Base Discount Per Residential Unit — Annual	$31.09	–
23	Base Master Meter Discount Per Residential Unit — Monthly	$2.59	–
24	Diversity Benefit Adjustment (Illustrative)	$3.18	–
25	Line Loss Adjustment	–	–
26	Net Discount (Monthly) (Illustrative)	$(0.58435)	–
27	Net Discount (Daily) (Illustrative)	$(0.01920)	–
28	Base Discount Daily Rate (Illustrative)	$0.08513	–

(a) Master Meter costs uses ML&P S proxy meter for connection and SL&P proxy meter for ongoing costs.

M. Conclusion

For all the above reasons, PG&E respectfully requests that the Commission adopt all of our residential rate design proposals.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

COMMERCIAL AND INDUSTRIAL RATE DESIGN

PACIFIC GAS AND ELECTRIC COMPANY
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CHAPTER 4
COMMERCIAL AND INDUSTRIAL RATE DESIGN

A. Introduction

In this chapter, Pacific Gas and Electric Company (PG&E) presents its 2023 General Rate Case Phase II (GRC II) rate design proposals for Commercial and Industrial (C&I) customers. Specifically, PG&E proposes to adjust Generation and Distribution components of C&I rates to move them closer to the cost of service. PG&E is not making any proposed rate design changes to the other components of C&I rates.[1]

PG&E considers two datapoints when designing C&I rates: (1) a rate's applicable marginal cost revenues and (2) marginal cost revenues scaled by the Equal Percent Marginal Cost (EPMC) multiplier. The EPMC scalar is the ratio between a schedule's revenue allocation and the marginal cost revenue. Unless supported by a clear policy objective, PG&E generally prefers sending TOU price signals based on the nominal marginal cost revenues for energy and capacity costs so that customers are not over-incentivized to shift their loads. However, in some cases PG&E uses EPMC-scaled marginal cost revenues as a benchmark for rate design to more evenly distribute non-marginal costs.

B. Summary of Proposals

Consistent with PG&E's overall rate design objectives in this proceeding (as outlined in Exhibit PG&E-3, Chapter 1), PG&E's C&I distribution and generation rate design proposals use marginal cost relationships to take a meaningful step to adjust rates to better reflect the cost of service while balancing other objectives such as rate stability and understandability. Rates based on the cost of service will better support the state's policy goals of promoting load flexibility and electrification while minimizing cross-subsidization between different segments of customers. By sending more accurate price signals, customers will

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[1] PG&E's rates are comprised of various rate components, including: Transmission, Distribution, Generation, Public Purpose Programs, Nuclear Decommissioning, Wildfire Fund Charge, New System Generation Charge, the Energy Cost Recovery Amount, Competition Transition Charge, Power Charge Indifference Adjustment, Wildfire Hardening Charge (WHC), Recovery Bond Charge, and Recovery Bond Credit.

be better equipped to make economically efficient decisions that both reduce their total bill as well as lower the cost PG&E must incur in the future to provide electric service. To align with this objective, the key changes PG&E proposes to C&I rate design include:

- Adjusting customer charges to better reflect EPMC-Scaled Marginal Customer Costs (MCC), which will result in lower volumetric energy charges and demand charges that better support California's decarbonization goals; and
- Adjusting peak to off peak period time-of-use (TOU) energy rate differentials for certain schedules, to send customers more cost-based priced signals to encourage them to shift more usage away from the high-cost peak period.

PG&E's proposed C&I rate designs balance moving toward the cost-basis with the competing objective of promoting customer stability and understandability. For many C&I rate schedules, the California Public Utilities Commission's (CPUC or Commission) 2020 GRC II Decision (D.21-11-016) largely maintained the same C&I rate designs the CPUC had previously adopted in PG&E's 2017 GRC II proceeding (D.18-08-013). Doing so allowed customers more time to acclimate to rate schedules with a TOU peak period that had shifted to later in the day (4-9 pm seven days a week) from the previous peak period that had run from noon to 6 pm on weekdays. In this 2023 GRC II, the CPUC's final decision on Track A (all but RTP rate design and implementation) is expected no earlier than mid-2026. By 2027, it will have been multiple years since the migration of many C&I customers to the updated 4–9 pm peak period, providing an adequate amount of time to acclimate to this transition.[2] While PG&E's proposals in this proceeding adjust current rate values to move them towards the cost of service, PG&E is not proposing to change existing C&I rate structures, including TOU period definitions, charge types, and eligibility thresholds. Maintaining the current rate structures, and leveraging the existing TOU periods to which C&I customers have become accustomed, allows the focus of PG&E's rate design proposals to be on providing customers with more accurate, cost-based price signals. This incentivizes customers to use electricity

2 The majority of C&I customers were transitioned from legacy rate schedules with 12-5 pm peak periods to new rate schedules with 4-9 pm peak periods on March 1, 2021. Advice Letter (AL) 6090-E/E-A.

in more efficient ways, which in turn can reduce future costs and rates for all customers. At the same time, where necessary to limit customer bill impacts, PG&E has moderated some of its C&I rate design proposals to move only part of the way towards full-cost rates in this proceeding.[3] In many cases, particularly for Small and Medium Light and Power rate schedules—which are further away from the cost-based targets—PG&E has proposed smaller movements towards full-cost rates to avoid more significant bill impacts from these rate design changes.

Finally, PG&E's proposals are intended to promote equity between customers by avoiding cost-shifts from certain customer segments to others. CPUC Rate Design Principle 8 states, "[r]ates should avoid cross-subsidies that do not transparently and appropriately support explicit policy goals."[4] In this proceeding, PG&E proposes to retain the existing demand eligibility requirements for the various customer classes within the C&I customer segment and remove exemptions from these requirements. Removing exemptions avoids potential cost shifts caused by customers taking service on rate schedules designed for customers with a lower demand.

There are approximately 530,000 customers taking service on C&I rate schedules as of January 1, 2024, divided into various classes as shown below in Table 4-1. A summary of the C&I rate schedules by customer class, key rate design changes adopted in the 2020 GRC II, and key rate design proposals made in this 2023 GRC II are summarized in Table 4-1, below. Except for Schedule A-1, as described further below, PG&E is not proposing any changes to its legacy C&I rate schedules (Schedules A-6, A-10, E-19, and E-20) which remain on the weekday noon - 6 pm peak period because these legacy rates are set to expire by the end of 2027 pursuant to a transition plan previously adopted by the CPUC in D.18-08-013. The previously-approved sunset date for these legacy rates will take place shortly after the expected implementation of the C&I rate changes adopted in the CPUC's final decision in this 2023 GRC II. Therefore, PG&E proposes to continue these rates "as-is" until they expire.

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3 See D.23-04-040, pp. 21-22, CPUC Rate Design Principle 10.

4 D.23-04-040, p. 20, CPUC Rate Design Principle 8.

TABLE 4-1
SUMMARY OF PG&E'S 2023 GRC II PROPOSED RATE DESIGN

Line No.	Customer Class	Rate Schedule(s)	2020 GRC II Settlement Adopted Rate Design Changes	2023 GRC II Proposed Rate Design Changes
1	Small Light and Power (SLP)	B-1, B1-ST, B-6, A-15, TC-1	• No changes to Schedules B-1, B1-ST, A-15, TC-1 • Increased generation and distribution energy rate differentials for Schedule B-6 towards adopted EPMC-scaled marginal cost differentials.	• Increase customer charges partially towards EPMC-scaled customer marginal costs and adjust customer charges in proportion with future changes in distribution revenue, consistent with energy charges. • Introduce distribution TOU price signals on Schedule B-1 and adjust TOU rate differentials for B-6, adding to existing generation TOU rates. • Adjust generation TOU rate differentials on B-1 and B-6 towards marginal cost. • No change to B1-ST TOU price signals. • Apply 75 kilowatt (kW) eligibility threshold for previously exempt SLP customers by 2028.
2		A-1, A-1 TOU, A-6	• No changes	• Modify A-1 to remain open to existing fixed usage customers. • No changes to A-1 TOU or A-6 because these schedules are approved to sunset by the end of 2027.
3	Medium Light and Power (MLP)	B-10, B-10 Option R	• No changes to rate design. • Established new rate Schedule B-10 Option R.	• Increase customer charge partially towards EPMC-scaled customer marginal costs. • Adjust B-10 energy TOU rate differentials towards marginal cost. • No changes to B-10 Option R.
4		A-10	• No changes	• No changes because this schedule is approved to sunset by the end of 2027.

TABLE 4-1
SUMMARY OF PG&E'S 2023 GRC II PROPOSED RATE DESIGN
(CONTINUED)

Line No.	Customer Class	Rate Schedule(s)	2020 GRC II Settlement Adopted Rate Design Changes	2023 GRC II Proposed Rate Design Changes
5	Large Light and Power (LLP) and Industrial	B-19/20, B-19/20 Option R, B-19/20 Option S	• Adjusted generation and distribution peak demand charges towards adopted EPMC-scaled marginal cost. • Adjusted distribution rates to account for the WHC rate component.	• Adjust customer charges towards EPMC-scaled customer marginal costs, with the exception of Schedule B-20T. • Adjust generation and distribution peak demand charges towards EPMC-scaled marginal cost. • Adjust generation energy charges towards EPMC-scaled marginal cost. • Adjust Option R/S generation and distribution energy charges towards marginal cost.
6		E-19/20	• No changes	• No changes because these schedules are approved to sunset by the end of 2027.
7	Standby	SB	• Revised generation reservation charges to move towards adopted marginal generation capacity cost.	• Adjust generation and distribution reservation and energy charges towards adopted marginal cost.
8		S	• No changes	• No changes because this schedule is approved to sunset by the end of 2027.

Note that the bill impacts referenced in this testimony compare present rates (as of July 1, 2024) to proposed rates with only the rate designs proposed in this testimony. This excludes the impacts of the revenue requirement allocation changes proposed elsewhere in this application so as to provide clear analysis of the impacts of PG&E's rate design proposals. However, Appendix C of Exhibit (PG&E-4) includes a set of proposed rates which include changes to both revenue allocation and rate design proposed in this proceeding.

C. Organization of the Rest of This Chapter

The remainder of this chapter is organized as follows:

- Section D – Rate Design for Small Light and Power;
- Section E – Rate Design for Medium Light and Power;
- Section F – Rate Design for Large Light and Power and Industrial;
- Section G – Rate Design for Standby;

- Section H – Conclusion; and
- Attachment A – Detailed Guidelines for Changing Rates for Revenue Changes.

PG&E's Real Time Pricing proposal for the various C&I customer classes can be found in Chapter 10. In addition, the following information regarding C&I rate design can be found in Exhibit (PG&E-4):

- Appendix A – Recorded 2022 and 2023 data for C&I customers;
- Appendix C – Present and proposed total and unbundled rates for C&I rate schedules;
- Appendix D – Illustrative bill impact comparisons of PG&E's proposed C&I rate design changes;
- Appendix F – SLP Customer Reports and Illustrative C&I rate designs in compliance with the CPUC's decision on PG&E's 2020 GRC II application; and
- Appendix J – Study of storage system performance under B-19 and B-20 Option S rates in compliance with the final decision in PG&E's 2017 GRC II.

D. Rate Design for SLP

Customers considered part of the SLP class include C&I customers on Schedules A-1, A-1TOU, A-6, A-15, B-1, B-6, B1-ST, and TC-1. The eligibility boundary between SLP and MLP (starting with Schedules A-10 and B-10) is 75 kW. Customers that have demands greater than 75 kW may not take service on the SLP rate schedules, unless they are solar customers specifically granted legacy treatment on Schedules A-6 or B-6 as adopted by the final decision in PG&E's 2014 GRC II proceeding and further described in Section 4, below. PG&E provides service to a wide variety of SLP customers, such as retail stores, restaurants, and offices. In general, SLP rates consist of a customer charge and volumetric energy charges.

Since the adoption of D.18-08-013, the TOU periods for non-legacy schedules have been defined as follows:

- Summer (June 1-September 30)
  - Peak: 4pm-9pm, daily
  - Part peak: 2pm-4pm and 9pm-11pm, daily (except for B-6)
  - Off peak: All other hours
- Winter (all other months)

- Peak: 4pm-9pm, daily
- Super off peak: 9am-2pm, daily
- Off Peak: All other hours
- Schedule B1-Storage has additional Part-peak periods from 2pm-4pm and 9pm-11pm, daily

A summary of PG&E's existing SLP rate schedules is presented in Table 4-2, below.

TABLE 4-2
SUMMARY OF SLP RATE SCHEDULES

Line No.	Rate Schedule	Purpose	Approximate Enrollment as of January 2024
1	B-1	Base rate schedule with mild TOU price signals	371,268
2	B-1 ST	Option to promote energy storage	86
3	A-1	Legacy schedule with flat rates by season	23,273
4	A-1 TOU	Legacy schedule with mild TOU price signals	2,376
5	B-6	Option with greater TOU price signal than B-1	60,510
6	A-6	Legacy schedule with greater TOU price signal than A-1 TOU	3,009
7	A-15	Flat rate by season for direct current lighting	468
8	TC-1	Flat rate Metered traffic-control equipment, <34MWh per month	12,855

PG&E proposes to maintain the current eligibility thresholds and TOU period definitions for SLP schedules to promote customer stability amidst the other rate design changes PG&E proposes for these schedules.

1. Overview

PG&E proposes the following for SLP rate schedules:

- Eligibility: Retain the current 75 kW SLP eligibility threshold, as described above;
- Seasons and TOU periods: Retain existing seasons and TOU periods adopted in D.18-08-013 and continued in D.21-11-016, as described above;
- Customer Charges: Update the proportion of distribution revenue collected from SLP customer charges to move them towards cost, as outlined in Section 2a;
- Distribution Energy Charges: Implement mild TOU price signals for Schedule B-1 and modify TOU rate differentials for Schedule B-6 to reflect marginal costs, as outlined in Section 2b;

- Generation Energy Charges: Increase TOU rate differentials towards cost for Schedules B-1 and B-6, as outlined in Section 3;
- Apply 75 kW Eligibility Requirements for exempt Schedule B-6/A-6 customers: Establish an end-date for the legacy treatment adopted by the decision in PG&E's 2014 GRC II proceeding, which provided no sunset date for customers with demands greater than 75 kW to remain on Schedules A-6/B-6 rather than be defaulted to the appropriate rate schedule for their demand (the "75kW Legacy Treatment"), as outlined in Section 4;
- Maintain Schedule A-1 for Existing Fixed Usage Customers: Remove end-of-2027 Sunset Date for existing fixed usage customers on Schedule A-1 so they may remain on A-1 indefinitely, and update Schedule A-1 to be a flat rate across seasons, as outlined in Section 5;
- Rules for Changes between GRCs: Modify rules for rate changes adopted by PG&E's 2020 GRC II for non-legacy rate schedules so that customer charges change along with future changes in distribution revenues, as outlined in Section 6.

2. Distribution Rate Design

a. Customer Charges

Currently, customer charges on Schedules B-1, B1-ST, B-6, and A-15 are $10 for single-phase and $25 for poly-phase service.[5] The single-phase customer charge last changed on January 1, 2012 when it increased from $9 per month to the current value of $10 per month[6]. However, over the 12-year period from 2012 to present, PG&E's distribution revenues have nearly tripled while the SLP customer charges have remained flat.[7] The current customer charges are disproportionately lower than the cost basis, which has required higher

5 Single-phase and poly-phase systems are two types of AC systems. Single-phase systems are common in many SLP and residential applications. Poly-phase (three-phase) are more practical in industrial settings.

6 AL 3973-E, filed December 19, 2011, approved August 14, 2012, effective January 1, 2012, Attachment 2.

7 See AL 3896-E-B, filed December 30, 2011, Table 3 and AL 7307-E, filed June 27,2024, Attachment 1a.

volumetric energy charges on these rate schedules to recover the allocated revenues.

In this proceeding, PG&E proposes to adjust these schedules' customer charges so that they recover approximately half of EPMC-scaled MCC for single-phase and Schedule TC-1 and one third of EPMC-scaled MCC for poly-phase. This results in proposed customer charges of $50 per month for single-phase, $100 per month for poly-phase, and $25 per month for Schedule TC-1. PG&E estimates that this adjustment will result in a reduction to volumetric energy rates of approximately 3.5¢/kWh across all TOU periods. Doing so will not only bring SLP rate schedules closer to the cost basis, but also increases the attractiveness to customers considering decarbonizing end uses through greater use of electrification technologies. PG&E's proposed customer charges are shown in Table 4-3, below.

Intuitively, increasing the customer charge and decreasing energy charges lower bills for larger customers and raises bills for smaller customers. While 45 percent of customers are seeing average bill increases of over 20 percent, the change in their nominal dollar amount from the updated customer charge generally will be no more than $40 to $75 (depending on whether the customer receives single-phase or poly-phase service). Conversely, 25 percent of SLP customers will see bill decreases averaging 5 percent. These customers account for approximately 73 percent of the kWh consumed by SLP customers.

Finally, PG&E proposes to adjust these moderated customer charges proportionally to future changes in distribution revenue between rate cases to maintain the rate relationships established by a final decision in this proceeding. This is consistent with the treatment applied to Schedules B-10, B-19, and B-20 and will ensure that future revenue requirement changes do not have a disproportional impact on energy charges. PG&E does not propose any changes to the customer charges for legacy Schedules A-1 and A-6, which are scheduled sunset by the end of 2027.

TABLE 4-3
SLP PROPOSED CUSTOMER CHARGE LEVELS

Line No.	Rate Schedule	Current	Proposed	EPMC-Scaled MCC
1	SLP Single-phase	$10	$50	$89
2	SLP Poly-phase	$25	$100	$285
3	TC-1	$15	$25	$51

b. Energy Charges

PG&E proposed limited rate design changes to SLP schedules in the 2020 GRC II because C&I customers were still in the process of transitioning to the new TOU periods. Now that this migration is complete, it is appropriate to propose more cost-based price signals to give customers an incentive to adjust more of their usage into off peak periods. After accounting for revenues generated from the proposed customer charges, the remaining distribution revenue is allocated to TOU energy charges.

Distribution energy rates for Schedule B-1 are currently differentiated by season, but not by TOU period. To better reflect time-differentiated Marginal Distribution Capacity Costs (MDCC), PG&E proposes to transition from this seasonal flat rate to time differentiated rates which recover 25 percent of the marginal cost revenues, with the remaining revenue collected through a flat energy charge. Table 4-4 provides the current and proposed rate differentials for each TOU period.

TABLE 4-4
SCHEDULE B-1 CURRENT AND PROPOSED DISTRIBUTION ENERGY CHARGE TOU DIFFERENTIALS

Line No.	TOU Period	Current	Proposed	Full Cost
1	Summer On Peak to Off		$0.02800	$0.11201
2	Summer Part Peak to Off		$0.01188	$0.04752
3	Winter On Peak to Super Off		$0.00190	$0.00762
4	Winter Off Peak to Super Off		$(0.00003)	$(0.00010)
5	Flat Summer to Winter	$0.02017	$0.04426[a]	–

(a) Illustrative only

Currently, Schedule B-6 has five existing TOU periods: two in the summer and three in the winter. The summer peak to off peak price differential of 9 cent-per kilowatt-hour (¢/kWh) currently is less than the 13 ¢/kWh price differential implied by marginal cost. As such, PG&E proposes to update the price differentials in Schedule B-6 which were last modified in October 2022, after they were approved in PG&E's 2020 GRC II proceeding.[8] By updating the rate design for Schedule B-6, a beneficial economic incentive enhances for SLP customers that can shift load to the off peak period. PG&E's proposed distribution energy rate differentials for Schedule B-6 are provided in Table 4-5, below.

TABLE 4-5
SCHEDULE B-6 CURRENT AND PROPOSED DISTRIBUTION ENERGY CHARGE TOU DIFFERENTIALS

Line No.	TOU Period	Current	Proposed
1	Summer On Peak to Off	$0.08769	$0.12722
2	Winter On Peak to Super Off	$0.00404	$0.03993
3	Winter Off Peak to Super Off	$0.00000	$0.03226

PG&E proposes to continue the current rate structure for both Schedules TC-1 and A-15. Once applicable A-15 customer charges are considered, residual revenue needed to maintain revenue neutrality with the class will be recovered through seasonal energy charges. Schedule TC-1 will continue to include a customer charge and recover its remaining revenue in its current form, as a non-time differentiated energy charge.

TABLE 4-6
SCHEDULES A-15 AND TC-1 PROPOSED DISTRIBUTION ENERGY CHARGES

Line No.	Rate	Current	Proposed
1	A-15 Summer	$0.19934	$0.17511
2	A-15 Winter	$0.17917	$0.14706
3	TC-1	$0.15597	$0.11879

[8] See AL 6713-E.

In D.18-08-013,[9] the Commission adopted a new SLP schedule, Schedule B1-ST, for eligible customers with storage systems. Schedule B1-ST was implemented in August 2020.[10] PG&E proposes to retain the existing rate design methodology adopted by the D.18-08-013 for distribution charges, including existing TOU rate differentials. More specifically, Schedule B1-ST has the same customer charge as Schedule B-1 with the remaining revenues recovered through demand and energy charges. As the schedule has very few customers, PG&E designs this schedule using the billing determinants of all Schedule B-1 customers.

3. Generation Energy Rate Design

Generation revenues are collected exclusively by energy charges for SLP customers. Schedule B-1 currently has a 7¢/kWh differential in the summer (peak versus off peak). This design is lower than the marginal cost basis of about 17¢/kWh. To better reflect the cost of service, PG&E proposes moderately increasing the differential to half of the marginal cost price signal, detailed in Table 4-7 below.

TABLE 4-7
CURRENT AND PROPOSED SCHEDULE B-1 GENERATION ENERGY CHARGE TOU DIFFERENTIALS

Line No.	TOU Period	Current	Proposed	Full Cost
1	Summer On Peak to Off	$0.07004	$0.08516	$0.17033
2	Summer Part Peak to Off	$0.02081	$0.01322	$0.02645
3	Winter On Peak to Super Off	$0.03253	$0.03455	$0.06910
4	Winter Off Peak to Super Off	$0.01642	$0.02129	$0.04258

Schedule B-6 currently has a summer peak to off peak rate differential of 17¢/kWh, or about 1¢/kWh lower than the marginal cost basis. PG&E proposes to set the TOU differential of Schedule B-6 to collect the full marginal cost basis, which results in a proposed summer on-peak versus off peak differential of about 17¢/kWh. This proposal allows Schedule B-6 to

9 See D.18-08-013, pp. 178-179, Ordering Paragraph (OP) 8.

10 See AL 5830-E.

continue to provide a more differentiated rate option for customers who are more capable of shifting usage outside of the peak period.

TABLE 4-8
CURRENT AND PROPOSED SCHEDULE B-6 GENERATION ENERGY CHARGE TOU DIFFERENTIALS

Line No.	TOU Period	Current	Proposed
1	Summer On Peak to Off	$0.16993	$0.17295
2	Winter On Peak to Super Off	$0.07563	$0.08358
3	Winter Off Peak to Super Off	$0.03608	$0.06071

PG&E proposes to continue the current rate design for both Schedules TC-1 and A-15. Energy rates for Schedule A-15 will be equal to the seasonally differentiated, non-TOU equivalent of Schedule B-1.

Consistent with the distribution rate design for Schedule B1-Storage, PG&E proposes continuation of the design adopted by D.18-08-013, without making any changes to TOU differentials at this time.

4. Sunset 75 kW Legacy Treatment of Large Customers on A-6/B-6

Schedule A-6 was originally open to all small and medium commercial customers with loads less than 500 kW (in three consecutive months over a 12-month period). Schedule A-6 was designed to be revenue neutral with Schedule A-1, with its primary feature being greater TOU price differentials. The high peak period rates made it popular among solar customers. As of March 1, 2021, Schedule A-6 is only available to qualifying solar legacy TOU period customers, or to qualifying customers without interval meters that can be read remotely by PG&E.[11] The Schedule A-6 tariff is currently set to expire by the end of 2027, at which time all customers must transition to new Schedule B-6 or other applicable new tariffs.

The 2014 GRC II final decision revised the size threshold for Schedule A-6 to 75 kW, consistent with Schedule A-1. The transfer of eligible current and future customers on Schedule A-6 to an otherwise-applicable schedule

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[11] See AL 6090-E-A which implemented tariff eligibility revisions to Schedule A-6 effective March 1, 2021.

began on November 1, 2015.[12] However, under the 75 kW Legacy Treatment provision approved in the 2014 GRC II final decision, customers who requested service on Schedule A-6 prior to March 31, 2017 [13] were allowed to stay on Schedule A-6 (and eventually Schedule B-6), with no end-date for this treatment set forth in the decision.[14]

As of June 2024, there is a combined total of about 2,000 customers enrolled on both Schedules A-6 and B-6 whose demand exceeds these schedules' the 75 kW eligibility requirement. To determine the benefit these customers are receiving, PG&E calculated illustrative bills for these customers by applying 2023 recorded usage to present rates for Schedule B-6 as of July 1, 2024. PG&E then performed the same calculation while also applying present rates for Schedule B-10. By comparing the total revenues under each of these two scenarios, PG&E has determined that these customers are receiving a total estimated windfall of approximately $15.5 million annually, which is not cost-based, and therefore is currently paid for by all non-participating customers.

As further background, the CPUC adopted a ten-year exemption period for migrating solar customers from legacy TOU periods to the current TOU periods, which also aligned with the expiration of tariffs with legacy TOU periods (Electric Rule 1). That exemption treatment will end on December 31, 2027 for public agencies, and July 31, 2027 for all other eligible non-residential customers.[15] PG&E proposes to use these same adopted dates (December 31, 2027 for public agencies and July 31, 2027 for all other non-residential customers) as the expiration dates for the 75 kW Legacy Treatment, so that customers on Schedules A-6 and B-6 whose demand is greater than 75 kW would also be transitioned to their appropriate rate schedule, concurrent with the closure of Schedule A-6.

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[12] See D.15-08-005, pp. 18-19, Section 7.1.7.7.

[13] See D.15-08-005, pp. 27-30, Section 8.2.

[14] See D.15-08-005, p. 39, OP 9.

[15] See D.17-01-006, p. 80, OP 5.

5. Continued Schedule A-1 Availability for Fixed Usage Customers

PG&E proposes that Schedule A-1 remain open for existing unmetered fixed usage customers. PG&E is not proposing any changes to how these customers currently take service or how they are billed. Without this proposal, customers on this service agreement will be left without a viable rate schedule when Schedule A-1 is sunset at the end of 2027.

There are 18,790 customers, accounting for $21.1 million of annual revenue,[16] who take service under "Agreements for Unmetered Low Wattage Equipment Connected to Customer-Owned Street Light Facilities" (Form No. 79-1048). This agreement serves streetlight mounted equipment rated at 150 watts or less, for example, telecommunications equipment, irrigation controls, and early warning systems. Currently their consumption of electricity is determined using the manufacturers' specifications and operating characteristics as submitted by the customer under Form No. 79-1048. Since none of these customers have any type of meter, it would be infeasible to transition them A-1 onto a TOU rate like Schedule B-1.

PG&E proposes that, effective January 1, 2028 (once solar customers enrolled in Schedule A-1 will have been transitioned to rate schedules with later TOU peak periods), Schedule A-1 should be adjusted to a flat rate schedule without seasonal rate differences and remain open for existing unmetered customers. This will avoid customer confusion around the different seasonal definitions between Schedules A-1 and B-1.

6. Changes to Distribution and Generation Rates Between GRCs

As described in Section 2a, above, for Schedules B-1, B1-ST, B-6, A-15, and TC-1, PG&E proposes to modify the rules for changes between GRCs adopted by the 2020 GRC II decision so that customer charges change on an equal percentage basis with the change in allocated distribution revenues. These rules are detailed in Attachment A to this chapter.

E. Rate Designs for MLP

This section includes rate design for MLP rate schedules (Schedules A-10, B-10, and B-10 Option R). Customers with demand less than 500 kW may take

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[16] As of May 2024.

service on these rate schedules. Customers in this class include customer types such as offices, retail stores, and schools. These schedules generally consist of a customer charge, a maximum (non-coincident) demand charge, and energy charges. With customers transitioning to Schedule B-10 beginning in March 2021, the legacy Schedules A-10 and A-10 TOU are closed to new customers and are currently set to expire by the end of 2027. Schedule B-10 Option R was recently adopted in PG&E's 2020 GRC II proceeding.[17]

TABLE 4-9
SUMMARY OF MLP RATE SCHEDULES

Line No.	Rate Schedule	Purpose	Approximate Enrollment as of January 2024
1	B-10	Base schedule with TOU energy charges and maximum demand charge.	38,342
2	B-10 Option R	Same kW eligibility as base schedule with additional requirement for onsite renewable generation.	Not yet available
3	A-10	Legacy schedule.	883

PG&E proposes to maintain the current eligibility and TOU period definitions for MLP schedules to promote customer stability amidst the other rate design changes PG&E proposes for these schedules.

1. Overview

PG&E proposes the following rate design for MLP rate schedules:

- Eligibility: Retain current eligibility threshold of up to 499 kW;
- Seasons and TOU periods: Retain the seasons and TOU periods adopted by D.18-08-013;
- Customer Charges: Update the proportion of distribution revenue collected from MLP customer charges to move them towards cost as outlined in Section 2a;
- Distribution Demand and Energy Charges: Implement mild TOU energy price signals for Schedule B-10 and modify demand charges as outlined in Section 2b;

[17] This schedule has not yet been implemented for reasons further described in Chapter 11 of this exhibit (PG&E-3).

- <u>Generation Energy Charges</u>: Adjust TOU rate differentials towards cost for Schedule B-10 as outlined in Section 3;
- <u>Schedule B-10 Option R</u>: Maintain Option R rate design adopted by 2020 GRC II decision as described in Section 4;
- <u>Rules for Changes Between GRCs:</u> Maintain rules for rate changes adopted by PG&E's 2020 GRC II decision.

2. Distribution Rate Design

a. Customer Charges

Currently, the customer charges on Schedules A-10 and B-10 are $326 per month, across all voltage levels. Based on PG&E's proposal, the full EPMC-scaled MCC would be $870 per month. To moderate bill impacts, PG&E proposes to increase the customer charge for these schedules by $274 to reach a proposed level of $600 per month, so that the new customer charge recovers just over half of the full-cost basis. Adoption of this proposal lowers revenues recovered from all demand and energy charge revenues by approximately 6 percent (on average 5.3¢/kWh across the class). Like the SLP proposal, increasing the customer charge and decreasing energy charges lower bills for larger customers and raises bills for smaller customers. While 11 percent of customers would experience average bill increases of 20 percent or more, the nominal increase in their bill would be no more than the $273 increase to the customer charge. Under PG&E's proposal, 28 percent of MLP customers would see bill decreases averaging 3 percent. These larger customers make up 70 percent of total sales for MLP customers, as measured by kWh.

b. Demand and Energy Charges

PG&E proposes to continue the seasons and TOU periods established by D.18-08-013 for Schedule B-10. PG&E further proposes implementing moderate TOU price signals in the distribution energy charges.[18]

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[18] See D.18-08-013, p. 153; D.21-11-016, p. 146.

After accounting for revenues generated by the customer charge, the remainder of distribution revenues on Schedule B-10 is collected by a non-coincident maximum demand charge and TOU energy charges. During the 2020 GRC II proceeding, PG&E did not propose changes to rate design as customers were transitioning to new TOU periods. In this proceeding, PG&E proposes to retain the existing split of remaining revenues between demand and energy charges, where 40 percent is allocated to demand charges and 60 percent to energy charges. To design the energy charges, PG&E proposes to establish a TOU rate differential by moving halfway towards marginal cost revenues based on PG&E's proposed MDCC, with the remaining revenue collected through a flat energy charge. This proposal is illustrated in Table 4-10 below.

TABLE 4-10
SCHEDULE B-10 CURRENT AND PROPOSED ENERGY CHARGE TOU DIFFERENTIALS

Line No.	Rate Schedule	TOU Period	Current	Proposed	Full Cost
1	B-10 S	Summer On Peak to Off	–	$0.05192	$0.10384
2	B-10 S	Summer Part Peak to Off	–	$0.02341	$0.04682
3	B-10 S	Winter On Peak to Super Off	–	$0.00226	$0.00452
4	B-10 S	Winter Off Peak to Super Off	–	$(0.00034)	$(0.00067)
5	B-10 S	Flat Summer to Winter	$0.01822	$0.02195[a]	–
6	B-10 P	Summer On Peak to Off	–	$0.05315	$0.10629
7	B-10 P	Summer Part Peak to Off	–	$0.02400	$0.04800
8	B-10 P	Winter On Peak to Super Off	–	$0.00222	$0.00445
9	B-10 P	Winter Off Peak to Super Off	–	$(0.00038)	$(0.00076)
10	B-10 P	Flat Summer to Winter	$0.01822	$0.02072[a]	–
11	B-10 T	Flat Summer to Winter	$0.00000	$0.00000	–

(a) Illustrative only.

3. Generation Energy Rate Design

Generation revenues are collected exclusively by energy charges for Schedule B-10. PG&E recommends using marginal generation capacity and energy costs to set the TOU differentials. PG&E proposes to transition to 75 percent of full marginal cost rate differentials with remaining revenue collected through a flat energy charge. PG&E's proposed rate differentials are illustrated in the table below by voltage.

TABLE 4-11
SCHEDULE B-10 CURRENT AND PROPOSED GENERATION ENERGY CHARGE TOU DIFFERENTIALS

Line No.	Rate Schedule	TOU Period	Current	Proposed	Full Cost
1	B-10 S	Summer On Peak to Off	$0.09425	$0.12860	$0.17147
2	B-10 S	Summer Part Peak to Off	$0.03257	$0.01953	$0.02604
3	B-10 S	Winter On Peak to Super Off	$0.07182	$0.05170	$0.06893
4	B-10 S	Winter Off Peak to Super Off	$0.03634	$0.03186	$0.04248
5	B-10 P	Summer On Peak to Off	$0.08913	$0.12883	$0.17178
6	B-10 P	Summer Part Peak to Off	$0.03083	$0.01957	$0.02609
7	B-10 P	Winter On Peak to Super Off	$0.06997	$0.05173	$0.06897
8	B-10 P	Winter Off Peak to Super Off	$0.03634	$0.03188	$0.04250
9	B-10 T	Summer On Peak to Off	$0.08681	$0.12753	$0.17005
10	B-10 T	Summer Part Peak to Off	$0.03007	$0.01983	$0.02644
11	B-10 T	Winter On Peak to Super Off	$0.06917	$0.05204	$0.06939
12	B-10 T	Winter Off Peak to Super Off	$0.03634	$0.03168	$0.04225

4. Schedule B-10 Option R

While PG&E has not yet implemented Option R for Schedule B-10, once implemented, PG&E proposes to continue the same rate design adopted by D.21-11-016.[19] More specifically, PG&E proposes to continue the rate relationships adopted by D.21-11-016 and continue applying the rules for revenue changes between GRCs. Based on present revenue requirements, this results in a customer charge of $660 for Schedule B-10 Option R, which continues to exceed PG&E's proposed customer charge for Schedule B-10.[20] This approach will also maintain the TOU rate differentials established by the marginal costs adopted in the 2020 GRC II decision, as outlined in Table 4-12.

TABLE 4-12
SCHEDULE B-10 OPTION R PROPOSED ENERGY CHARGE TOU DIFFERENTIALS

Line No.	Rate Schedule	TOU Period	Distribution	Generation
1	B-10 S	Summer On Peak to Off	$0.09713	$0.19949
2	B-10 S	Summer Part Peak to Off	$0.05090	$0.04864
3	B-10 S	Winter On Peak to Super Off	$0.00310	$0.10071
4	B-10 S	Winter Off Peak to Super Off	$0.00000	$0.05418
5	B-10 P	Summer On Peak to Off	$0.10123	$0.17770
6	B-10 P	Summer Part Peak to Off	$0.05141	$0.04547
7	B-10 P	Winter On Peak to Super Off	$0.00332	$0.08829
8	B-10 P	Winter Off Peak to Super Off	$0.00000	$0.04799
9	B-10 T	Summer On Peak to Off	$0.00000	$0.15015
10	B-10 T	Summer Part Peak to Off	$0.00000	$0.03621
11	B-10 T	Winter On Peak to Super Off	$0.00000	$0.07623
12	B-10 T	Winter Off Peak to Super Off	$0.00000	$0.04081

F. Rate Designs for LLP and Industrial

This section includes rate design for LLP Schedules B-19, B-19V and Industrial Schedule B-20. Customers with demands less than 500 kW may voluntarily elect to take service on Schedule B-19V. Customers with demands

[19] A.19-11-019, PG&E's Motion for Adoption of Commercial and Industrial Rate Design Supplemental Settlement Agreement, Attachment 1, pp. 10-14, as approved by D.21-10-016.

[20] In the Settlement Agreement, adopted in D.21-11-016, the customer charge shall be the EPMC-scaled MCAC adopted by the 2020 GRC II decision ($296.37/customer month) subject to the following limitations: (1) it shall not be lower than the customer charge determined for Schedule B-10, and (2) it shall be no more than twice the value of the customer charge determined for Schedule B-10.

between 500 kW and 1,000 kW must take service on Schedule B-19. This schedule serves customers such as offices, hotels, hospitals, and manufacturing facilities. Customers with demand greater than 1,000 kW are required to take service on Schedule B-20. Schedules B-19 and B-20 have the most cost-based rate structure as they recover costs in customer, demand (TOU and non-coincident), and TOU energy charges. Schedules B-19V, B-19, and B-20 also include Option R and Option S for qualifying customers with photovoltaic solar or storage systems.

TABLE 4-13
SUMMARY OF LLP RATE SCHEDULES

Line No.	Rate Schedule	Purpose	Approximate Enrollment as of January 2024
1	B-19	Base schedule for customers between 500 kW and 1,000 kW	1,385
2	B-19V	Opt-in for customers < 500 kW	31,049
3	B-20	Base schedule for customers >1,000 kW	955
4	B-19/20 Option R	Same kW eligibility as base schedule with additional requirement for qualifying technologies	136
5	B-19/20 Option S	Same kW eligibility as base schedule with additional requirement for onsite energy storage	48

1. Overview

PG&E proposes the following rate for Schedules B-19V, B-19, and B-20:

- Eligibility: Retain existing eligibility thresholds;
- Seasons and TOU periods: Retain the seasons and TOU periods adopted by D.18-08-013;
- Customer Charges: Update the portion of distribution revenue collected from LLP Customer charges to move them towards cost as discussed in Section 2a;
- Distribution Demand Charges: Modify the proportion of distribution revenue collected from TOU demand charges and non-coincident demand charges to move towards cost as discussed in Section 2b;
- Generation Demand and Energy Charges: Modify generation TOU rate differentials and the proportion of revenue collected from TOU demand

charges, non-coincident demand charges, and energy charges to move towards cost as discussed in Section 3;

- Option R and Option S: Adjust TOU rate differentials towards cost and maintain the Option R and Option S rate designs adopted by the 2020 GRC II decision as described in Section 4; and
- Rules for changes between GRCs: Maintain rules for rate changes between GRCs adopted by PG&E's 2020 GRC II decision; including rate design treatment established by D.23-11-005 to adjust distribution rates to recover the wildfire hardening bond revenue requirement through customer and demand charges, rather than through energy charges.

2. Distribution Rate Design

a. Customer Charges

PG&E proposes to adjust customer charges for Schedules B-19 and B-20 to fully recover EPMC-scaled MCC with the exception of Schedule B-20T which retains the current customer charge.[21] PG&E's proposed customer charges are shown in Table 4-14, below.[22] As indicated in the table, a customer charge based on EPMC-scaled MCC would be a significant increase for transmission voltage level service for Schedule B-20. This is largely due to the revenue allocation methodology adopted by the 2020 GRC II final decision which allocates a greater share of wildfire, catastrophic events, and hazardous substance revenue requirements to transmission-voltage customers which creates a large EPMC multiplier. In the interest of bill stability, PG&E proposes holding customer charges constant for Schedule B-20T. Finally, PG&E proposes to retain the current methodology and adjust customer charges for these rate schedules in proportion to future changes in distribution revenue.

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[21] The customer charge for B-19V is set equal to the customer charge applicable to Schedule B-10.

[22] The current and proposed customer charges in Table 4-14 include the adjustment for the Wildfire Hardening Charge established by D.23-11-005 in PG&E's 2020 GRC II proceeding.

TABLE 4-14
SCHEDULE B-19 AND B-20 CURRENT AND PROPOSED CUSTOMER CHARGE

Line No.	Rate Schedule	Current	Proposed	EPMC-Scaled MCC
1	B-19 T	$3,664	$5,080	$5,080
2	B-19 P	$2,508	$2,692	$2,692
3	B-19 S	$1,663	$2,154	$2,154
4	B-20 T	$11,596	$11,596	$59,885
5	B-20 P	$3,220	$2,899	$2,899
6	B-20 S	$3,109	$4,561	$4,561

b. Demand and Energy Charges

PG&E proposes to continue the seasons and TOU periods established by D.18-08-013 for LLP rate schedules.

After accounting for revenues raised by the customer charge, PG&E proposes to collect the remaining distribution revenue through distribution demand charges. The exception to this being the distribution rate adjustment to account for the WHC that is further explained below.

In PG&E's 2020 GRC II, EPMC-scaled marginal costs were used as a benchmark to adjust the rate design for Schedules B-19 and B-20. PG&E has followed a similar approach in this proceeding by first determining the revenues that would be collected in peak and part peak TOU demand charges based on the EPMC-scaled primary distribution marginal costs. However, recent increases in non-marginal distribution revenue have led to an increase in the distribution EPMC multiplier. To adjust for this change, PG&E proposes to recover 60 percent of EPMC-scaled marginal costs in TOU demand charges for Schedules B-19 and B-20 Primary and Secondary voltages. Next, PG&E allocates remaining distribution revenues to non-coincident demand charges.

Finally, PG&E proposes to continue the rate design treatment established by D.23-11-005 to adjust distribution rates for Schedules B-19 and B-20 to recover the equivalent of the wildfire hardening charge revenue requirement through customer and demand charges, rather than through energy charges.[23] To do this, PG&E establishes a negative distribution energy charge exactly equal to the Wildfire Hardening Fixed Recovery Charge (WHFRC) for Schedules B-19 and B-20, and excluding Option R and Option S, and applies an equal percent increase to customer charges and demand charges to recover the revenue shortfall resulting from the negative distribution energy rates to ensure revenue neutrality. The present and proposed rates are included in Appendix C of Exhibit PG&E-4.

3. Generation Demand and Energy Rate Design

Generation revenues are recovered through TOU demand charges and energy charges on Schedules B-19 and B-20. Similar to the distribution rate design, PG&E proposes to use EPMC-scaled marginal generation capacity and energy costs as a benchmark to set TOU demand and energy charges. PG&E proposes to adjust demand and energy charges to recover EPMC-scaled marginal capacity costs and marginal energy costs, respectively.

4. Option R and Option S

PG&E proposes to continue offering Option R and Option S rates and follow the same rate design adopted by D.21-11-016, and subsequently modified by D.23-11-005.

For Option R, distribution rates will be designed by converting 75 percent of the distribution revenue derived from the peak and part-peak distribution demand charges applicable to Schedules B-19 and B-20, excluding the modification for the Wildfire Hardening Charge, to energy charges, with the remaining 25% collected through peak and part-peak demand charges. Energy charge revenues are collected through summer peak, part-peak, and off peak periods; there are no winter energy charges. To calculate the energy charges, PG&E proposes to first determine TOU rate differentials based on distribution marginal cost revenues. The remaining revenues are collected through energy charges on an equal-cents basis.

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[23] D.23-11-005 was adopted on November 2, 2023, and first implemented in rates effective January 1, 2024.

Option S distribution rates will continue to be anchored to the Option R design for B-19V, B-19, and B-20. Revenue associated with the non-coincident demand charges for Option R will be converted to a daily demand charge applicable in the peak period (80 percent share), and to a special non-coincident demand charge applicable in all hours except 9 am – 2 pm (20 percent share). Revenue associated with the peak and partial peak demand charges on Option R will be converted to peak and partial-peak daily demand charges.

Option R generation rates are designed by converting 100 percent of the generation revenue derived from peak and part-peak demand charges to energy charges. To calculate the energy charges, PG&E proposes to first determine TOU rate differentials based on generation marginal capacity cost revenues. The remainder of revenues are collected through energy charges on an equal-cents basis. These generation energy charges are then added to the energy charges for the base rate schedules. Generation rates for Option S will be the same as the generation rates for Option R for Schedules B-19V, B-19, and B-20.

5. Changes to Distribution and Generation Rates

For Schedules B-19 and B-20, PG&E proposes to use the existing rules for changes between GRCs adopted by D.21-11-016 and D.23-11-005 to implement the revenue allocation adopted in this proceeding and for revenue requirement changes before the next GRC II proceeding. These rules are summarized for this customer class in Attachment A, Part C.

G. Rate Design for Standby

PG&E provides standby service under Schedule SB to customers whose non-utility source of generation is capable of regularly and completely serving their entire electrical load. The largest portion of the load currently served by PG&E under Schedule SB is comprised of customers who take service on transmission service voltages. Schedule SB includes customer charges, reservation charges, TOU energy charges, and all applicable utility charges, terms and conditions for those customers whose non-utility source of generation is capable of regularly and completely serving their entire electrical load.

A limited number of customers require "supplemental" standby service from PG&E. Supplemental standby service is provided to customers who rely on non-utility sources of generation for only a portion of their total load. These customers pay all other charges under the terms and conditions of the otherwise-applicable rate schedule. In addition, under this type of standby service, the customer pays the standby reservation charge from Schedule SB only for that portion of its load that is ordinarily supplied by the non-utility generation resource.[24]

1. Overview

PG&E proposes the following rate design for Standby:

- Eligibility: Retain existing eligibility thresholds;
- Seasons and TOU periods: Retain the seasons and TOU periods adopted by D.18-08-013;
- Customer Charges: Maintain current practice of setting customer charges equal to customer charges on otherwise applicable schedule;
- Distribution Reservation and Energy Charges: Modify the proportion of distribution revenue collected from reservation charges, non-coincident demand charges, and customer charges to move towards cost;
- Generation Demand and Energy Charges: Modify generation TOU rate differentials and the proportion of revenue collected from non-coincident demand charges and energy charges to move towards cost;
- Rules for changes between GRCs: Maintain rules for rate changes between GRCs adopted by PG&E's 2020 GRC II decision.

2. Distribution Rate Design

a. Customer Charges

Customer charges for Schedule SB have historically been set at the same levels as applied under the otherwise applicable rate schedule for most customer classes. PG&E proposes to continue this practice, and thus set the standby customer charges at the same levels as recommended for

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24 Demand charges billed under the terms of the otherwise-applicable rate schedule are reduced by the amounts paid for reservation capacity under Schedule SB, in those instances where it is demonstrated that the maximum demand during a given billing cycle was attributable to non-operation of the customer's generator.

the otherwise-applicable rate schedules as presented in this exhibit. For agricultural customers, PG&E proposes to continue applying the Schedule AG-B customer charge, which is $65 per month as proposed in Chapter 5 of this Exhibit (PG&E-3). Consistent with the proposed changes in customer charges, PG&E has refreshed the reduced customer charges applicable to Schedule SB to exclude the share of marginal customer equipment costs from the customer charges in the otherwise-applicable schedule, as presented in Appendix C.

Currently, Schedule SB applies a basic service fee of $5 per month for residential customers. However, the Decision Addressing Assembly Bill 205 Requirements for Electric Utilities (D.24-05-028) adopted a residential customer charge of up to $24.15 per month. To be consistent with all other customer classes, PG&E proposes to apply the distribution portion of the otherwise applicable residential customer charge to Schedule SB once the residential customer charge is implemented rather than applying the existing $5 basic service fee.

b. Reservation and Energy Charges

Once standby customer charge revenue is determined, the remaining allocated distribution revenue is collected through energy and reservation charges.[25] For primary and secondary distribution voltages, PG&E combines the billing determinants and marginal costs together before designing their distribution energy and reservation charges in aggregate. For these voltages, PG&E proposes to assign peak demand-related share of distribution costs to energy charges, differentiated by TOU period. Doing so will revise the rate differentials between TOU periods. PG&E proposes to assign remaining revenues to reservation charges and equal cent energy charges on an equal percentage basis of present rate revenues for these rate components. For transmission voltage customers, PG&E proposes to follow the current practice and collect all remaining distribution revenue through the distribution reservation charge.

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25 For transmission voltage distribution rates, all remaining revenues are collected through the reservation charge.

3. Generation Energy and Reservation Charges Rate Design

PG&E collects generation revenues through reservation charges and energy charges for all voltage levels. For primary and secondary voltages, PG&E combines the billing determinants and marginal costs together before designing energy and reservation charges for these customers.

PG&E proposes to collect the energy-related share of the total generation revenue assigned to Schedule SB in TOU energy charges. PG&E has assigned the energy related share of generation costs to each TOU period based on the generation marginal energy cost revenue, with residual revenue being recovered on an equal-cent basis. Consistent with past practice, PG&E proposes to assign capacity-related share of the assigned generation revenue to the generation component of the standby reservation charge.

4. Changes to Distribution and Generation Rates

PG&E proposes to retain the rules for changing standby distribution and generation rates adopted by D.21-11-016 in PG&E's 2020 GRC II proceeding. Rules for changing distribution and generation rates, subject to the initial adjustments described above, are set forth in Attachment A, Part D.

H. Conclusion

In this chapter, PG&E has discussed its 2023 GRC II rate design proposals for C&I customers. These proposals move rates closer to costs of service in ways which will support the state's electrification goals and reduce cross subsidization, while also moderating certain changes in furtherance of greater bill stability. Therefore, PG&E requests the commission approves the C&I rate designs proposed in this chapter.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

ATTACHMENT A

DETAILED GUIDELINES FOR CHANGING RATES FOR REVENUE CHANGES

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DETAILED GUIDELINES FOR CHANGING RATES FOR REVENUE CHANGES

A. Schedules B-1, B-6, A-15, and TC-1

Changes to Small Light and Power legacy rates will continue to utilize the existing rules for changes between General Rate Cases (GRC) adopted by Decision (D.) 21-11-016 in order to implement the revenue allocation adopted in this proceeding, as well as for revenue requirement changes before the next GRC Phase II proceeding. For Schedules B-1, B-6, A-15, and TC-1, Pacific Gas and Electric Company (PG&E) adjusted the rules adopted by D.21-11-016 to allow for customer charges to change in proportion to changes in distribution revenues. Rules for changes to distribution and generation rates for Schedules B-1, B-6, A-15, and TC-1 are set forth below.

1. Distribution Rate Design

The distribution revenue requirement will be allocated to each rate schedule as provided in Exhibit (PG&E-3), Chapter 2. Distribution rates will then be designed to collect the allocated revenue. Customer charges, demand charges, and energy charges each will be designed to change by the same percentage necessary to collect the required revenue. However, the change in energy charges will be determined by the equal cents per kilowatt-hour (kWh) adder that is required to collect the necessary change in energy charge revenue. This approach to setting the distribution energy charges will ensure that the differential in rates between seasons and time-of-use (TOU) periods remains the same on a cents-per-kWh basis.

2. Generation Rate Design

The generation revenue requirement will be allocated to each rate schedule as provided in Exhibit (PG&E-3), Chapter 2. Generation rates will then be designed to collect the allocated revenue. Demand and energy charges will be designed to each change by the same percentage necessary to collect the required revenue. However, the change in energy charges will be determined by the equal cents-per-kWh adder that is required to collect the necessary change in energy charge revenue. This approach to setting the generation energy charges will ensure that the differential in rates between seasons and TOU periods remains the same on a cents-per-kWh basis.

B. Schedules A-10 and B-10

Changes to legacy rates (Schedule A-10) and the B Series rates (Schedules B-10 and B-10 Option R), PG&E will continue to utilize the existing rules for changes between GRCs adopted by D.21-11-016 in order to implement the revenue allocation adopted in this proceeding as well as for revenue requirement changes before the next GRC Phase II proceeding. Rules for changing distribution and generation rates are set forth below.

1. Distribution Rate Design

The distribution revenue requirement will be allocated to each rate schedule as provided in Exhibit (PG&E-3), Chapter 2. Distribution rates will then be designed to collect the allocated revenue. For Schedules B-10 and A-10, customer charges, demand charges, and energy charges will be designed to change by the same percentage necessary to collect the required revenue. However, the change to energy charges will be determined by the equal cents-per-kWh adder required to collect the necessary change in energy charge revenue. This approach to setting the distribution energy charges for Schedules A-10 and B-10 will ensure that the differential in energy rates between seasons and TOU periods remains the same on a cents-per-kWh basis for these schedules.

2. Generation Rate Design

The generation revenue requirement will be allocated to each rate schedule as provided in Exhibit (PG&E-3), Chapter 2. Generation rates will then be designed to collect the allocated revenue. Demand and energy charges will be designed to each change by the same percentage necessary to collect the required revenue for Schedules A-10 and B-10. However, the change in energy rates will be determined by the equal cents-per-kWh adder required to collect the necessary change in energy charge revenue. This approach to setting the generation energy charges for

Schedules A-10 and B-10 will ensure that the differential in rates between seasons and TOU periods remains the same on a cents-per-kWh basis.

C. Schedules E-19V, E-19, E-20, B-19V, B-19, and B-20

Changes to legacy rates (E-19V, E-19, and E-20) and the B Series rates (B-19V, B-19, and B-20) will continue to utilize the existing rules for changes between GRCs adopted by D.21-11-016, and subsequently modified by D.23-11-005,[1] in order to implement the revenue allocation adopted in this proceeding as well as for revenue requirement changes before the next GRC Phase II proceeding. Rules for changing distribution and generation rates are set forth below.

1. Distribution Rate Design

The distribution revenue requirement will be allocated to each rate schedule as provided in Exhibit (PG&E-3), Chapter 2. Distribution rates will then be designed to collect the allocated revenue. For Schedules E-19V and B-19V, the customer charge will be set to the customer charge for Schedules A-10 and B-10. All remaining customer charges and demand charges on these schedules will be changed by the same percentage necessary to collect the required revenue. Customer charge changes resulting from the method described above for transmission service voltages will be limited, if applicable, to ensure that the residual distribution maximum demand charge collects the revenue associated with the California Public Utilities Commission (CPUC or Commission) Fee.[2]

For Schedules B-19 and B-20 only, and excluding Option R and Option S, PG&E will establish a negative distribution energy charge component exactly equal to the Fixed Recovery Charge[3] associated with wildfire hardening recovery bonds and a corresponding equal percent increase to distribution-related customer, time-related demand charges, and

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1 D.23-11-005, pp. 14-15, Ordering Paragraph (OP) 1.

2 The CPUC Fee refers to energy charges defined in Public Utilities Code (Pub. Util. Code) Section 431(b)(2) and authorized by the Commission, pursuant to Pub. Util. Code Section 431(a).

3 Fixed Recovery Charge refers fixed recovery charges defined in Pub. Util. Code Section 850(b)(7) and authorized by the Commission, pursuant to Pub. Util. Code Section 850(a)(2).

non-time-related demand charges such that the net effect of the increase and decrease to distribution charges is revenue neutral.[4]

For Option R, distribution rates will be designed by converting 75 percent of the distribution revenue derived from peak and part-peak distribution demand charges, excluding the adjustments for the Fixed Recovery Charge noted above, to energy charges. Energy charges will be designed to change by the equal cents-per-kWh adder required to collect the necessary change in energy charge revenue. This approach to setting the distribution energy charges for Option R will ensure that the differential in energy rates between seasons and TOU periods remains the same on a cents-per-kWh basis.

Option S will begin from the Option R design for B-19V, B-19, and B-20 only. Revenue associated with the non-coincident demand charges for Option R will be converted to a daily demand charge applicable in the peak period (80 percent share), and to a special non-coincident demand charge applicable in all hours except 9 a.m. to 2 p.m. (20 percent share). Revenue associated with the peak and partial peak demand charges on Option R will be converted to peak and partial-peak daily demand charges.

2. Generation Rate Design

The generation revenue requirement will be allocated to each rate schedule as provided in Exhibit (PG&E-3), Chapter 2. Generation rates will then be designed to collect the allocated revenue. Demand and energy charges for schedules E-19V, E-19, E-20, B-19V, B-19, and B-20 will be designed to each change by the same percentage necessary to collect the required revenue. When necessary, however, winter generation energy rates will be adjusted to ensure that the Super Off-Peak (SOP) rate is not negative.

For Option R, generation rates will be designed by converting 100 percent of the generation revenue derived from peak and part-peak generation demand charges and converting that revenue to energy charges. Energy charges will be designed to change by the equal cents-per-kWh adder required to collect the necessary change in energy charge revenue.

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4 D.23-11-005, pp. 14-15, OP 1.

This approach to setting the generation energy charges for Option R will ensure that the differential in energy rates between seasons and TOU periods remains the same on a cents-per-kWh basis. Generation rates for Option S will be the same as the generation rates for Option R for Schedules B-19V, B-19 and B-20.

D. Schedule SB

Changes to Schedule SB will utilize will continue to utilize the existing rules for changes between GRCs adopted by D.21-11-016 to implement the revenue allocation adopted in this proceeding, as well as for revenue requirement changes before the next GRC Phase II proceeding. Rules for changing distribution and generation rates, after the initial rate adjustments described in Exhibit (PG&E-3), Chapter 4 are implemented, are set forth below.

1. Distribution Rate Design

The distribution revenue requirement will be allocated to each rate schedule as provided in Exhibit (PG&E-3), Chapter 2. Distribution rates will then be designed to collect the allocated revenue. Customer charges will be set based on the rate for the otherwise applicable schedule.

For Schedule SB, reservation and energy charges will be designed to change by the same percentage necessary to collect the required revenue. However, the change to energy charges will be determined by the equal cents-per-kWh adder required to collect the necessary change in energy charge revenue. This approach to setting the distribution energy charges for Schedule SB will ensure that the differential in energy rates between seasons and TOU periods remains the same on a cents-per-kWh basis for these schedules.

2. Generation Rate Design

The generation revenue requirement will be allocated to each rate schedule as provided in Exhibit (PG&E-3), Chapter 2. Generation rates will then be designed to collect the allocated revenue. Reservation and energy charges will be designed to change by the same percentage change necessary to collect the required revenue. However, the change to energy charges will be determined by the equal cents-per-kWh adder required to collect the necessary change in energy charge revenue. This approach to setting the generation energy charges for Schedule SB will ensure that the differential in energy rates between seasons and TOU periods remains the same on a cents-per-kWh basis for these schedules. When necessary, however, winter generation energy rates will be adjusted to ensure that the SOP rate is not negative.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

AGRICULTURAL RATE DESIGN

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AGRICULTURAL RATE DESIGN

A. Introduction

This chapter presents Pacific Gas and Electric Company's (PG&E) distribution and generation rate design proposals for the Agricultural (AG) customer class.

The AG customer class represents one of California's largest business sectors. California has been the number one state in the country for producing AG commodities,[1] with our state accounting for nine of the top ten counties for AG production in the United States.[2] Within all of the AG customers that PG&E serves in its service territory, this includes service for eight of the top 10 AG counties (Fresno, Monterey, Kern, Merced, San Joaquin, Stanislaus, Santa Barbara, and Kings). PG&E's AG customers produce numerous types of products including tree nuts, fruit, livestock products, grains, and vegetables. Many of the end uses of electricity in our AG class are related to irrigation activities and other support activities such as nut hulling, cold storage/cooling for fresh produce, and overhang fans for cows in dairy farms.

AG customers generally prefer simple rate structures and bill stability. In past rate design proceedings, PG&E has made changes to the AG rates taking customer preference into careful consideration. For example, PG&E: (1) streamlined the number of rate schedules from thirteen to seven based on customer feedback regarding rate simplification, and (2) shortened the Time-of-Use (TOU) peak period from 4-9 p.m. to 5-8 p.m. considering the operational safety concerns raised by AG customers who have workers in the fields.[3] In this proceeding, PG&E's AG rate design proposals continue our effort

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1 United States (U.S.) Department of Agriculture, available at: <https://www.ers.usda.gov/faqs/#Q1> (accessed Sept. 11, 2024).

2 California Department of Food and Agriculture, Nine California Counties Make Top-10 List for Ag Sales in the US (Feb. 13, 2024), available at: <https://plantingseedsblog.cdfa.ca.gov/wordpress/?p=27335#:~:text=Fresno%20County%20ranked%20%231%20in,%2C%20Santa%20Barbara%2C%20and%20Kings> (accessed Sept. 11, 2024).

3 Decision (D.) 18-08-013, pp.35-36.

to better serve AG customers while better reflecting updated marginal costs to send more accurate cost-based price signals to support efficient energy use.

B. Summary of Proposals

PG&E's key AG rate design proposals in this proceeding are summarized in the following major categories: customer charges, demand and energy charges, rate changes between General Rate Case Phase IIs (GRC II), and AG-C's Demand Charge Rate Limiter (DCRL) update.

First, our updated marginal cost analyses show that AG customer charges are significantly lower than their actual cost basis. PG&E has not changed the AG customer charges since 2017. Thus PG&E proposes to increase customer charges so they move towards the level that would be reached based on the Equal Percent Marginal Cost (EPMC)-scaled Marginal Customer Cost (MCC), as further described in Chapter 1 of this Exhibit (PG&E-3). PG&E proposes to increase customer charge for:

- Small Agriculture (AGA) from $21 to $31 per month;
- Medium Agriculture (AGB) from $28 to $65 per month; and
- Large Agriculture (AGC) from $44 to $160 per month.

Doing this would move toward the EPMC-scaled MCC by 8 percent for AGA, by 10 percent for AGB, and by 20 percent for AGC. Increasing the customer charge allows reductions to energy and demand charges, which makes AG rate schedules more accommodating to electrification opportunities and creates greater stability by reducing volatility in customer bills between both month-to-month bills and between wet years and dry years.

Second, for demand charges and energy charges, PG&E proposes to modify TOU rate differentials and the proportion of revenue collected from demand charges to move towards cost while still maintaining the pumping hour relationships between Schedules AG-A1 and AG-A2, and between Schedules AG-B and AG-C, as established in prior GRC II proceedings. In summary, PG&E proposes to increase the summer peak hour energy (and demand[4]) rates while decreasing most of other TOU energy rates and reduce max demand charges.

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4 Only AG-C and AG-FC have the summer peak demand charge component.

Third, for rate changes between GRC Phase IIs, PG&E proposes to continue the rate structure and TOU price differentials and preserve intra-class rate schedule relationships for revenue requirement changes before the next GRC II proceeding. In addition, PG&E also proposes to change customer charges proportionally to future changes in distribution revenue between rate cases to maintain the rate relationships established by a final decision in this proceeding. This approach is consistent with the treatment currently applied to Commercial and Industrial (C&I) Rate Schedules B-10, B-19, and B-20 and will ensure that future revenue requirement changes do not have a disproportional impact on demand and energy charges.

Lastly, PG&E proposes to modify Schedule AG-C's DCRL mechanism,[5] to better support the California Public Utilities Commission (CPUC or Commission) Rate Design Principle No. 8 that:

> [R]ates should avoid cross-subsidies that do not transparently and appropriately support explicit state policy goals.[6]

The numbers used in calculating the DCRL rate rider are outdated and resulted in an increased cross-subsidy. The subsidy has increased from the estimated $15 million in 2020 GRC II, to about $39 million in 2023, which includes about $14 million recovered within AG-C, and about $25 million provided from non-AG-C customers.

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5 DCRL is a rate rider for customers on Schedule AG-C. When the sum of billed demand and energy charges on a monthly bill produces an average rate per kWh in excess of the DCRL (currently 50 cents per kWh), the customer is only billed the amount equal to its total kWh usage multiplied by the 50 cents per kWh, plus the customer charge (more details in Section G).

6 D.23-04-040, p. 2.

TABLE 5-1
SUMMARY OF PG&E'S 2023 GRC II PROPOSED AG RATE DESIGN

Line No.	Rate Group	Rate Schedule(s)	2020 GRC II Adopted Rate Design Settlement[a]	2023 GRC II Proposed Rate Design Changes
1	Small AG (AGA)	AG-A1, AG-A2, AG-FA	No changes to rate design Created new optional rate Schedules AG-A3	Increase customer charges partially towards fully-scaled customer marginal costs. Update existing TOU rate differentials towards marginal cost-based TOU differentials. Reduce maximum demand charges towards the cost basis No change to AG-A3 rate design method adopted in 2020 GRC II[b]
2	Medium AG (AGB)	AG-B, AG-FB, AG-B2	No changes to rate design Created new optional rate Schedules AG-B2	Increase customer charges partially towards fully-scaled customer marginal costs. Update existing TOU rate differentials towards marginal cost-based TOU differentials. Reduce max demand charges towards the cost basis No change to AG-B2 rate design method adopted in 2020 GRC II
3	Large AG (AGC)	AG-C, AG-FC	No changes to rate design Recalculated the revenue shortfalls from DCRL and updated the rate adder to recover the revenue shortfall	Increase customer charges partially towards fully-scaled customer marginal costs. Update existing TOU rate differentials towards cost-based TOU differentials. Adjust demand charges towards cost-based level Update the DCRL and the rate adder
4	Legacy Schedules	AG-1, AG-4, AG-5, AG-R, AG-V[c]	Eliminated monthly TOU meter charges	No changes because these schedules are approved to sunset by the end of 2027.

TABLE 5-1
SUMMARY OF PG&E'S 2023 GRC II PROPOSED AG RATE DESIGN
(CONTINUED)

Line No.	Rate Group	Rate Schedule(s)	2020 GRC II Adopted Rate Design Settlement[(a)]	2023 GRC II Proposed Rate Design Changes
5	Overall	All non-legacy AG schedules	Established standard interim GRC adjustment rules[(d)]	Revise the interim GRC rules to include that customer charges change proportionally to the future changes in distribution revenue, consistent with demand and energy charges.

(a) 2020 GRC II Final Decision (D.21-11-016), p. 136.

(b) The 2020 GRC II AG Rate Design Settlement Agreement recommended the creation of new optional AG rate Schedules AG-A3 and AG-B2 that reduce the summer off-peak energy charges below the electric bundled system average rate. This would be accomplished by widening the summer on-peak versus summer off-peak differential on a cents-per-kilowatt-hour (¢/kWh) basis, such that total off-peak energy charges would be set one-tenth of a cent below the bundled system average rate.

(c) The "legacy" AG rates include small customer Schedules AG-1A, AG-4A, AG-5A, AG-RA, and AG-VA; medium customer Schedules AG-1B, AG-4B, AG-4C, AG-RB, and AG-VB; and large customer Schedules AG-5B and AG-5C.

(d) The standard interim GRC rules was described 2020 GRC II AG Rate Design Settlement Agreement (p11), including a revenue balancing adjustments as necessary, to establish break-even annual irrigation pumping hours or usage levels such that AG-A2 is generally better than AG-A1 above 1,300 annual pumping hours, and AG-C is generally better than Schedule AG-B above 1,500 annual pumping hours.

Note that the bill impacts referenced in this testimony compare present rates (as of July 1, 2024) to proposed rates with only the rate designs proposed in this testimony. This excludes the impacts of revenue requirement allocation changes proposed elsewhere in this application. However, Appendix C of Exhibit (PG&E-4) includes a set of proposed rates which include changes to both revenue allocation and rate design proposed in this proceeding.

C. Organization of the Rest of This Chapter

The remainder of this chapter is organized as follows:

- Section D – Background;
- Section E – Customer Charges;
- Section F – Demand and Energy Charges;
- Section G – DCRL Update; and
- Section H –Conclusion.

PG&E's Real-Time Pricing (RTP) proposal for the AG customer class can be found in Chapter 10. In addition, the following information regarding AG rate design can be found in Exhibit (PG&E-4):

- Appendix A – Recorded 2023 data for AG customers;
- Appendix C – Present and proposed rates for AG rate schedules; and
- Appendix D – Illustrative bill impact comparisons of PG&E's proposed AG rate design changes.

D. Background

PG&E's AG class consists of approximately 88,000 customers in total, served on the following schedules in Table 5-2 below. The default rate schedules in each group are highlighted bold.

TABLE 5-2
AG RATE SCHEDULES

Line No.	AG Rate Schedule Groups	Rate Schedules within each Group	Customer Size	Number of Customers	Percent of total
1	AGA (<35 kilowatts (kW))	AG-A1, AG-A2, AG-A3[b], AG-FA	Small	44,000	50%
2	AGB (>=35 kW)	AG-B, AG-B2[c], AG-FB	Medium	19,000	21%
3	AGC (>=35 kW)	AG-C, AG-FC	Large	21,000	24%
4	Legacy Rates		Various	4,000	5%

(a) Customer counts are rounded to the nearest thousand.
(b) Approved but not yet implemented into billing system.
(c) Approved but not yet implemented into billing system.

Approximately 95 percent PG&E's AG customers (about 84,000) take service on one of the implemented seven TOU rate schedules with the 5-8 p.m. peak period in the AGA, AGB, and AGC rate groups. The other approximately 4,000 AG customers are still on the legacy AG rate schedules, most of whom are Net Energy Metering (NEM) customers.

All the non-legacy AG rates, except for Schedule AG-A3 and AG-B2, were first adopted in either the 2017 GRC II or 2019 Rate Design Window (2019 RDW) decisions (D.18-08-013 and D.19-05-010, respectively). Back in these proceedings, PG&E collaborated with the California Farm Bureau and Agriculture Energy Consumers Association (AG Parties) and made efforts to improve rate design for its AG customers, based on customer feedback requesting simpler and easier-to-understand rate options. PG&E consolidated thirteen legacy rate schedules to seven, which included four default rate schedules AG-A1, AG-A2, AG-B and AG-C,[7] and three optional rate schedules AG-FA, AG-FB, and AG-FC, with peak hours on five days per week instead of seven.[8] For days with on-peak periods, these seven rate schedules all have on-peak hours of 5 to 8 p.m., and all other hours are off-peak. Also, unlike TOU rate schedules for C&I customers, these new AG TOU rate schedules do not have partial peak or super-off-peak hours, therefore the TOU structure is simpler. Since March 1, 2021, customers have been transitioning from the

[7] Generally, AG-A1 and AG-B are designed for lower load factor customers with fewer operating hours and contain lower demand charges and higher energy charges than AG-A2 and AG-C, respectively.

[8] Customers can select two days of the week to have no peak hours (Wednesday and Thursday, Saturday and Sunday, or Monday and Friday).

legacy rate schedules to the new rate schedules. As shown in Table 5.2, most AG customers are now on the new rate schedules.

Although 12 out of the 13 legacy AG rate schedules[9] still exist in the AG class rate portfolio, PG&E does not propose any changes to these legacy rate schedules in this proceeding, because they are scheduled to expire at the end of 2027.

Schedules AG-A3 and AG-B2 are created pursuant to the 2020 GRC II AG Rate Design Settlement Agreement.[10] They are not yet available to AG customers for reasons further described in Chapter 11 of Exhibit (PG&E-3), but will be added to PG&E's AG rate schedule portfolio. These two optional rate schedules are designed to reduce the summer off-peak energy charges below the electric bundled system average rate by one-tenth of a cent, by widening the summer on-peak versus summer off-peak differential in ¢/kWh. The illustrative AG rate design in this chapter will include these two prospective rate schedules as well.

In its 2020 GRC II proceeding, PG&E limited proposals on AG rate design changes, considering the upcoming default from legacy rates to new TOU rates. The "interim GRC rules"[11,12] were applied to update the AG rates in 2020 GRC II, without applying marginal cost updates. Therefore, many AG rate design values and rules were established in either PG&E's 2017 GRC II or 2019 RDW proceedings. When submitting this 2023 GRC II Application, most AG customers have been on these new TOU rates for three and a half years, so they have had time to become more accustomed to the new TOU periods.

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9 The legacy rates are either non-TOU energy rates or with on-peak hours of 12 to 6 p.m.

10 A.19-11-019, PG&E's Motion for Adoption of Agricultural Rate Design Supplemental Settlement Agreement, pp. 3-4.

11 The "interim GRC rules" allow the demand and energy rates increase by the same percentages, and the TOU rates increase by the same ¢/kWh to preserve the TOU price differentials.

12 "PG&E proposes to preserve the AG rate design adopted in the GRC as modified by the 2019 RDW by applying 'interim GRC rules' to the slate of new default and voluntary AG rates adopted in the 2019 RDW, as modified to preserve intra-class rate schedule relationships, such as the 1,500 pumping hour break-even level, where AG-C is generally better for customers than AG-B. This will stabilize the rates with later TOU hours as AG customers adapt to the new later TOU hours of 5-8 p.m. that will become mandatory beginning in March 2021." A.19-11-019, Exhibit (PG&E-3), p. 5-11, lines 6-13.

Therefore, this is right time to make proposals to adjust these rates towards cost.

E. Customer Charges

1. Proposed Customer Charges

PG&E's current AG customer charges have not been updated since PG&E's 2017 GRC II because PG&E limited its AG rate design proposals and made no changes to customer charges, considering AG customers were then in the process of being defaulted from their legacy TOU rates to rates with new TOU periods.[13] It is appropriate to update customer charges now because the majority of AG customers[14] have been on the new TOU rate schedules for five years by the time this GRC is implemented (which is estimated to be no earlier than mid-2026). PG&E's refreshed marginal cost results in Exhibit (PG&E-2), Chapter 8 confirm that, current AG customer charges are significantly lower than their cost basis.[15] More specifically, the current AG-A customer charge only covers 18 percent of the full-cost basis, the current AG-B and AG-C customer charge only covers about 8 percent of the full cost.

To better align with the cost-causation principles of rate design, balanced with other objectives such as bill stability and customer acceptance, PG&E proposes to make modest progress to move customer charges toward the EPMC-scaled MCC levels, as shown in Table 5-3.

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13 A.19-11-019, Exhibit (PG&E-3), p. 5-2, lines 4-7.

14 Since March 1, 2021, customers have been transitioning from the legacy rate schedules to the new rate schedules. As of 2024, about 95.5 percent of AG customers are on the new rate schedules. PG&E still has about 4,000 solar legacy TOU period AG customers who will keep transitioning into updated TOU period rates by the end of 2027 or their solar legacy TOU period end date, whichever comes first. Also, only 9 out of the 4,000 AG customers have not transitioned due to the lack of interval meters that can be read remotely, and PG&E will make effort to transition them as well by 2027.

15 Full-cost basis include RCS, MCEC, and MLEC scaled by the schedule's EPMC percentage.

TABLE 5-3
COMPARISON OF PROPOSED AG CUSTOMER CHARGES
WITH FULL EPMC-SCALED MCC RESULTS

Line No.	AG Rate Schedule Group	Current Customer Charges[a]	Proposed Customer Charge	EPMC-Scaled MCC	Current Percent of EPMC-Scaled MCC	Proposed Percentage of EPMC-Scaled MCC
1	AGA	$21	$31	$117	18%	26%
2	AGB	$28	$65	$357	8%	18%
3	AGC	$44	$160	$562	8%	28%

(a) Current customer charges are rounded up to 0 decimal point. The unrounded customer charges are $20.97 for AGA, $27.87 for AGB, and $43.63 for AGC, per month. .

For small AG customers, PG&E proposes to only increase AGA customer charge by $10, even though the gap between the EPMC-scaled MCC and the current fixed charge is close to $100. A significant consideration is that small AG customers tend to have more idle months with no usage. For example, tomato growers tend to have idle winter months between crops. Increasing the customer charge results in a greater bill impact for these small farmers with more idle months. The selection of a $10 increase is further supported by the inflation rates since the current fixed charge was proposed in 2016. Based on the California Consumer Price Index (CPI) from 2016 to 2023,[16] combined with an estimated 3 percent annual inflation from 2024 to 2027, when the rate proposed in this proceeding is anticipated to be implemented, the customer charge reaches to approximately $31.

[16] California Department of Finance, CPI (1955-2024), available at: <https://www.cdfa.ca.gov/AHFSS/cabb/docs/202406_notice_Feb_California_Consumer_Price_Index_1955-2024.pdf> (accessed Sept. 11, 2024).

TABLE 5-4
CALIFORNIA CONSUMER PRICE INDEX
2016-2023 HISTORICAL DATA, AND 2024-2027 FORECAST

Line No.	Year	CPI	Inflation	Customer Charge
1	2016	255.303	–	$21
2	2017	262.802	2.9%	$22
3	2018	272.51	3.7%	$22
4	2019	280.638	3.0%	$23
5	2020	285.315	1.7%	$23
6	2021	297.371	4.2%	$24
7	2022	319.224	7.3%	$26
8	2023	331.804	3.9%	$27
9	2024	N/A	3%	$28
10	2025	N/A	3%	$29
11	2026	N/A	3%	$30
12	2027	N/A	3%	$31

For medium and large AG customers, PG&E proposes to increase AGB customer charges from $28 to $65 per month, which represents a 10 percent movement towards EPMC-scaled MCC, and to increase AGC customer charges from $44 to $160 per month, which represent a 20 percent movement towards EPMC-scaled MCC. Medium and large AG customers have fewer idle months over the year compared to small AG customers, therefore we can make greater progress, on a nominal dollar basis, moving customer charges towards the full EPMC-scaled MCC. Plus, the gaps between their current customer charges and the cost-based charges are much bigger than that of small AG customers.

Before being migrated to the updated TOU periods in March 2021 in accordance with the 2017 GRC II final decision, many customers who are currently on Schedules AG-B and AG-C had been on legacy Schedules AG-4C and AG-5C, with customer charges of $65 (legacy AG-4C) and $160 (legacy AG-5C), respectively. Therefore, PG&E's proposal to adjust Schedule AG-B and AG-C customer charges to the $65 and $160 are in line with the customer charges that many of these customers previously experienced.

2. Policy Alignment and Customer Benefit

Increasing customer charges not only better aligns with CPUC policy, but also benefits the overall AG class.

First, increasing customer charges can reduce the volumetric charges based on kW and kilowatt-hour (kWh) usage. A bigger portion of the customer bill becomes predictable, and therefore brings more stability when AG customers plan their budget for the next year.

Second, increasing customer charges and lowering energy and demand charges will make AG rate schedules more accommodating to electrification opportunities. Although many AG customers' energy uses are already electric, there are potentially more electrification applications for the AG industry in the foreseeable future, for example, replacing gas powered greenhouse systems with electric run systems, utilizing future electric tractors, forklifts, and sprayers,[17] deploying robotic cow milking equipment, etc.

PG&E also recognizes that, while increasing the AG customer charge can reduce some customers' bills, it also increases bills for others, since rate design is a zero-sum game that does not change the revenue requirement collected by rates. Therefore, in determining PG&E's customer charge proposal here, PG&E examined bill impacts to assess the degree of change customers would experience. Tables 5-3, 5-4, and 5-5 summarizes the overall bill impact.[18] Within each rate schedule, about 24-40 percent of customers are estimated to have bill reductions, and about 16-30 percent of customers are expected to experience bill increase of 10 percent or more, who are relatively low usage customers. Among these low usage customers, only about 1 percent of AG-B and 3 percent of AG-C customers have an average monthly bill increase greater than the nominal increase in the customer charge—some of which are NEM customers with high exports and negative average usage. Since the energy charges are reduced, their export compensation was reduced.

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17 California Air Resources Board, Advanced Clean Off-Road Equipment List Fact Sheet (July 2024), pp. 17-29, Zero-Emission Off-Road (Agricultural) Equipment, available at: <https://ww2.arb.ca.gov/sites/default/files/2024-07/ZEE_List.pdf> (accessed Sept. 11, 2024).

18 The bill impact was based on the year of 2023, which is a wet year. The bill impact would have been lower if it were based on a dry year, since AG customers would have fewer idle months throughout a dry year compared to a wet year. The bill impact in this Section assumes no DCRL for present and proposed rates, so PG&E's DCRL proposal in Section G is not reflected. Percentages are rounded so they may not sum up to 100. Bill amount and kWh usage are also rounded, and groupings of fewer than 0.5 percent of customers are not shown.

TABLE 5-5
PERCENT OF CUSTOMERS ON EACH RATE SCHEDULE BY BILL IMPACT

Line No.	Rate Schedule	Bill Change	Bill Decrease	0-5% Increase	5-10% Increase	Over 10% Increase
1	AGA-1	Less than $0	40%	–	–	–
2		$0-$10	–	20%	9%	30%
3		Over $10	–	–	–	–
4	AGA-2	Less than $0	39%	–	–	–
5		$0-$10	–	32%	6%	16%
6		Over $10	–	6%	1%	–
7	AG-B	Less than $0	33%	–	–	–
8		$0-$37	–	30%	7%	24%
9		Over $37	–	5%	1%	1%
10	AG-C	Less than $0	24%	–	–	–
11		$0-$116	–	38%	13%	22%
12		Over $116	–	–	–	3%

TABLE 5-6
AVERAGE MONTHLY BILL IMPACT BY BILL IMPACT GROUP

Line No.	Rate Schedule	Bill Change	Bill Decrease	0-5% Increase	5-10% Increase	Over 10% Increase
1	AGA-1	Less than $0	$(16)	–	–	–
2		$0 $10	–	$3	$6	$9
3		Over $10	–	–	–	–
4	AGA-2	Less than $0	$(19)	–	–	–
5		$0 $10	–	$5	$8	$10
6		Over $10	–	$16	$15	–
7	AG-B	Less than $0	$(72)		–	–
8		$0 $37	–	$15	$24	$34
9		Over $37	–	$67	$66	$77
10	AG-C	Less than $0	$(237)	–	–	–
11		$0 $116	–	$51	$89	$106
12		Over $116	–	–	–	$118

TABLE 5-7
AVERAGE MONTHLY USAGE kWh BY BILL IMPACT GROUP

Line No.	Rate Schedule	Bill Change	Bill Decrease	0-5% Increase	5-10% Increase	Over 10% Increase
1	AG-A1	Less than $0	1,250	–	–	–
2		$0 $10	–	309	71	9
3		Over $10	–	–	–	–
4	AG-A2	Less than $0	2,698	–	–	–
5		$0 $10	–	973	123	8
6		Over $10	–	2,134	366	–
7	AG-B	Less than $0	4,798	–		
8		$0 $37	–	2,429	358	(44)
9		Over $37	–	7,131	1,326	(130)
10	AG-C	Less than $0	44,044	–	–	–
11		$0 $116	–	7,241	2,339	237
12		Over $116	–	–	–	16

3. Benchmark Customer Charges

PG&E compared its proposed AG customer charges to those of six other adjacent utilities, as shown in Table 5-6, below. These other utilities' AG customer charges vary by the size of customers (in kW). Among the benchmarked utilities, larger AG customers tend to have higher customer charges compared to smaller AG customers. The customer charges for larger AG customers range from $80 to $525 per month. PG&E's proposed highest AG customer charge of $160 per month for large AG customers falls within the benchmark range. For small and medium AG customers, the customer charges range from $13.55 to $101.33 per month, and PG&E's proposed AG customer charges are also within the benchmark range.

TABLE 5-8
BENCHMARK AG CUSTOMER CHARGES

Line No.	Utility	AG Rate Customer charges ($/Month)	Effective Date
1	Sacramento Municipal Utility District	ASN (<=30 kW): $13.55 AON (<=30 kW): $18.25 ASD (31 to 499 kW): $31.45 AOD (31 to 499 kW): $109.60	Sep 22,2023
2	Southern California Edison Company	TOU-PA-2 (<200 kW): $89.46 TOU-PA-3 (200 to 500 kW): $524.81	May 29, 2024
3	San Diego Gas & Electric Company	TOU-PA (<=20 kW): $25 TOU-PA2 (20 to 500 kW): Secondary $227.27; Primary $116.94 TOU-PA3 (>20 kW): • 20-75 kW: $41.5 • 75-100 kW: $70.12 • 100-200 kW: $87.29 • >200 kW: $144.54	Feb 29, 2024
4	Modesto Irrigation District	P-3: $14 P-4 (>=1000 kW): $200	Jan 1, 2024
5	Merced Irrigation District	AG-2 (0-199 kW): $100	May 1, 2021
6	Turlock Irrigation District	FD (Demand): $52 FE (Energy): $28 FT (TOU): $82	Jan, 2015
7	Pacific Power, California	PA 20: • <=50 kW: $101.33 • >50 kW: $209.33	April 1, 2024
8	PG&E	AGA (<35 kW): $31 AGB (>35 kW): $65 AGC (>35 kW): $160	Proposed

F. Demand and Energy Charges

PG&E proposes to update maximum demand charges, summer peak demand charges, and energy charges to better align these rates with the underlying marginal costs calculated in Exhibit (PG&E-2), while balancing customer bill stability and preserving features and relationships among rate schedules. PG&E proposes no changes to the seasons and time-of-use period definitions.

For background, in prior GRC II and 2019 RDW proceedings, PG&E did not have any customers on these new Schedules (AG-A1, AG-A2, AG-B and AG-C), and the billing determinants and marginal cost inputs for these Schedules were derived from those of legacy rate schedules. PG&E combined AG-A1 and AG-A2 billing determinants to design AG-A1 and AG-A2, and combined AG-B and AG-C billing determinants to design AG-B and AG-C. It then shifted revenues in between AG-A1 and AG-A2, and revenues in between AG-B and AG-C to reach the targeted pumping hour relationship: (1) among medium and large AG customers, Schedule AG-C is generally better for (higher load factor) customers than Schedule AG-B when the pumping hours are longer than 1,500 hours per year; and (2) among small AG customers, Schedule AG-A2 is generally better for (higher load factor) customers than Schedule AG-A1 when the pumping hours are longer than 1,300 hours per year.

In this proceeding, PG&E proposes to calculate AG-A1, AG-A2, AG-B, and AG-C rates separately using their specific billing determinants, allocated revenue, and marginal costs inputs.[19] Since PG&E already has customers on these Schedules, it proposes to calculate these rates using inputs directly associated to their customers. Also, instead of shifting revenues in between Schedules to reach the target pumping hour relationships, PG&E proposes to utilize the rate design features, such as demand charge/energy charge splits, to achieve the target pumping hour relationship. Once the rate designs are approved in GRC II, for rate changes between subsequent GRC Phase IIs, PG&E proposes to continue the revenue rebalancing method to preserve

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19 Although AG-A1 and AG-A2 marginal costs input are separated, the values are very close. Therefore, the price differentials listed in the following sections are set the same for both AG-A1 and AG-A2.

intra-class rate schedule relationships for revenue requirement changes before the next GRC II proceeding.

1. Distribution

After accounting for revenues generated by the customer charge, the remainder of distribution revenues are collected by demand charges and energy charges. PG&E proposes to keep the existing split of remaining revenues between demand and energy charges for AG-A1 and AG-A2, and adjust it for AG-B and AG-C, which still results in reduction in the maximum demand charges for all rate schedules while preserving the previously established features of each rate schedule, such as the pumping hour breakeven relationships. This proposal and the resulted max demand changes are illustrated in Table 5-8 below.

TABLE 5-9
SPLIT OF DISTRIBUTION DEMAND CHARGES AND ENERGY CHARGES

Line No.	Rate Schedule	Current Demand Charge Share	Proposed Demand Charge Share		Max Demand Charge Reduction
1	AG-A1	50%	50%	-	(9)%
2	AG-A2	90%	90%	-	(2)%
3	AG-B	50%	60%		(10)%[a]
4	AG-C	86%	96%		(7)%[b]

(a) The percentage reduction shown in Table 5-9 for AG-B are for Secondary voltage customers. Primary voltage max demand charge reduces by 1%, and Transmission max demand charge increases by 16 percent.

(b) The percentage reduction shown in Table 5-9 for AG-C are for Secondary voltage customers. Primary and Transmission voltage max demand charges decrease by 1 percent.

To design the energy charges, PG&E proposes to partially move peak-to-off-peak price differentials towards the marginal cost-based differentials (the peak-to-off-peak primary distribution marginal cost differentials) considering the rate stability. The remaining revenue is collected through a flat energy charge. This proposal is illustrated in Table 5-10 below.

TABLE 5-10
CURRENT AND PROPOSED AG DISTRIBUTION ENERGY CHARGE TOU DIFFERENTIALS

Line No.	Rate Group[(a)]	TOU Period	Current	Full Marginal Cost-based	Proposed
1	AGA	Summer On-Peak to Off	0.046	0.119	0.075
2	AGA	Winter On-Peak to Off	0.003	0.004	0.003
3	AGB	Summer On-Peak to Off	0.050	0.044	0.048
4	AGB	Winter On-Peak to Off	0.003	(0.004)	0.000
5	AGC	Summer On-Peak to Off	0.010	0.044	0.024
6	AGC	Winter On-Peak to Off	0.000	0.001	0.001

(a) AG-A3 and AG-B2 summer price differentials are different compared to rates in their rate groups.

Schedule AG-FA, AG-FB, and AG-FC (AG-F Schedules) currently have higher peak-to-off-peak differentials compared to their corresponding base Schedules AG-A, AG-B and AG-C (base Schedules). However, based on the updated marginal cost, their peak-to-off-peak differentials have become very close to those of AG-A, AG-B and AG-C. Therefore, PG&E proposes to set the AG-F peak-to-off-peak differentials the same as those for base Schedules. This way, AG-F share the same price differential signals as their corresponding base Schedules. Meanwhile, since customers on Schedule AG-F have peak hours on five days per week instead of seven, they have relatively fewer sales counted as on-peak hour sales, compared to customers on base Schedules. Therefore, their TOU energy charges are slightly higher than the energy charges of the base Schedules, which naturally function as a premium in exchange for obtaining two off-peak days each week.[20]

Schedule AG-A3 and AG-B3 are designed to reduce the summer off-peak energy charges below the electric bundled system average rate by one-tenth of a cent, by widening the distribution summer on-peak versus summer off-peak differential in ¢/kWh. Therefore, their summer peak-off-peak differentials are higher than their base Schedules AG-A1 and AG-B, respectively.

20 AG-FA, AG-FB, and AG-FC are revenue neutral to AG-A1, AG-B, and AG-C, respectively.

Lastly, AG-C also has a Distribution Summer Peak Demand charge which was adopted in 2019 RDW.[21] PG&E added this demand charge to mitigate the number of highly impacted customers in the TOU transition. PG&E proposes to keep this rate component, since it is consistent with the higher average load factor nature of this group of customers, and it is the appropriate rate component to recover the time-varying portion of the distribution capacity cost. The current charge is about $12.68/kW, and PG&E proposes to update the rate in this proceeding, so it reflects 110 percent of primary distribution marginal cost, which increases it to about $18.56/kW.[22] This proposal represents a balance among cost-based rate design, rate stability, and maintaining the pumping hour balance.

2. Generation

Generation revenues are recovered purely through TOU energy charges on Schedules AG-A and AG-B, and through both summer peak demand charges and TOU energy charges on Schedule AG-C.

For TOU energy charges, PG&E proposes to better reflect the peak-to-off-peak Generation Capacity marginal cost[23] and Generation Energy marginal cost differentials in the peak-to-off-peak price differentials for AG-A, AG-B, and AG-C rate groups, for both summer and winter. Based on the marginal cost values from Exhibit (PG&E-2),[24] PG&E proposes to set the marginal cost based peak-to-off-peak differentials for AG-A winter, AG-B winter, AG-C summer and winter. However, PG&E proposes to move half-way towards the marginal cost-based peak-to-off-peak differentials for AG-A and AG-B summer rates, given the gaps between the current and cost-based differentials for them are relatively bigger than others.

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[21] D.19-05-010 approved the 2019 RDW Settlement Agreement. The Settlement parties agreed to PG&E's rate design for AG-C which contains establishing "a new on-peak summer distribution demand charge of $5 that had been zero." A.18-11-013, Exhibit PGE_002, p. 11.

[22] The increase is offset by the decrease of Generation summer peak demand charge and results in a combined 1 percent decrease compared to the current total summer peak demand charge.

[23] Not for AG-C, because AG-C has all the Gen Capacity revenue recovered via summer peak demand.

[24] Exhibit (PG&E-2), Chapters 2 and 3.

TABLE 5-11
CURRENT AND PROPOSED AG GENERATION ENERGY CHARGE TOU DIFFERENTIALS

Line No.	Rate Group[(a)]	TOU Period	Current	Full Marginal Cost-Based	Proposed
1	AGA	Summer On Peak to Off	0.120	0.184	0.152
2	AGA	Winter On Peak to Off	0.026	0.038	0.038
3	AGB	Summer On Peak to Off	0.123	0.188	0.156
4	AGB	Winter On Peak to Off	0.026	0.019	0.019
5	AGC	Summer On Peak to Off	0.029	0.023	0.023
6	AGC	Winter On Peak to Off	0.026	0.029	0.029

(a) AG-A3 and AG-B2 summer price differentials are different compared to rates in their rate groups.

For summer peak demand charges, AG-C is the only Schedule among AGA, AGB, and AGC that has this rate component. PG&E proposes to slightly adjust the existing split of remaining revenues between demand and energy charges, from 20 percent to 19 percent, to reflect the capacity related share of the generation marginal cost.

G. DCRL Update

The DCRL is a rate rider for customers on Schedule AG-C only. It was first adopted by D.18-08-013 which approved the 2017 GRC II AG Rate Design Settlement Agreement.[25] Normally, AG-C customers have high load factors with long hours of energy usage. However, occasionally, such customers might only run their big pumps or other equipment for just a couple of days, and leave the equipment idle for the rest of the billing period. When this happens, without the DCRL, the customer would be billed the full amount for maximum demand charges and peak demand charges, as applicable, during the billing cycle, plus a small amount of energy charges due to very low usage. This leads to a relatively high average rate per kWh for the billing period.

To mitigate the high average rate, the DCRL is designed so customers do not pay a very high average rate per kWh during any individual billing period. If the sum of billed demand and energy charges on a Schedule AG-C customer's monthly electric bill, excluding the fixed monthly customer charge, divided by total kWh usage, produces an average rate per kWh in excess of the current

25 D.18-08-013, p. 174, Conclusion of Law (COL) 58. A.16-06-013, PG&E's Motion for Adoption of the Agricultural Rate Design Supplemental Settlement Agreement (Apr. 8, 2021), approved in D.18-08-013, p. 8.

DCRL of 50 cents per kWh, then the average rate is capped by the DCRL. When this occurs, the customer is billed an amount equal to their total kWh usage in the billing period multiplied by the $0.50 per kWh DCRL, plus the customer charge.

The revenue shortfall due to the DCRL is then captured and spread to AG-C distribution rates for recovery through an equal cent-per-kWh distribution energy charge on a forecast basis in GRC II proceedings.[26] The revenue shortfall has increased from the estimated $15 million in 2020 GRC II, to about $39 million in 2023, which includes about $14 million recovered within AG-C and about $25 million provided from non-AG-C customers.

The two DCRL related values are outdated and contribute to the increasing subsidy. First, the 50 cents per kWh threshold was set by the D.18-08-013 which adopted the 2017 GRC II AG Rate Design Settlement Agreement.[27] As the demand charges increased over the past six years driven by distribution revenue increases, an increasing number of AG-C customer bills have reached the 50 cents per kWh average rate threshold and have received a DCRL bill reduction. This has caused the cost shift resulting from the DCRL to increase over time as demand charges increase. Second, the current DCRL revenue shortfall figure applied in the distribution rate was last calculated and adopted in the 2020 GRC II. Since it is not reset every year, the cost shift is not always retained within AG-C customers. When this occurs, the excess revenue shortfall spills over and is recovered from all customers.

To comply with the CPUC rate design principles and mitigate cost shift increases, PG&E proposes to reset the DCRL from 50 cents per kWh to $1 per kWh in this proceeding and plans to revisit the value in the next GRC filing. PG&E has also re-estimated the revenue shortfalls attributable to the $1 per kWh DCRL and proposes to keep recovering the shortfall through an equal cent-per-kWh adder to all Schedule AG-C TOU distribution energy charges in both seasons, per the adopted methodology. PG&E further proposes to update the DCRL based on the percentage changes of the AG-C average rate in

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26 This is the adopted methodology by D.18-08-013 and D.19-05-010.

27 D.18-08-013, p. 174, COL 58. A.16-06-013, PG&E's Motion for Adoption of the Agricultural Rate Design Supplemental Settlement Agreement (Apr. 8, 2021), approved in D.18-08-013, p. 8.

PG&E's Annual Electric True-Up (AET) rate changes each year. This way, the revenue shortfall increase can be mitigated, and cost shift can be largely retained within Schedule AG-C and does not unintentionally flow to other non-AG-C customers.

H. Conclusion

PG&E's 2023 GRC II AG rate design proposals, as detailed in this chapter, are overall reasonable and should be adopted. PG&E's proposals consider AG customers' needs and feedback related to simplicity, understandability, and bill stability. Moreover, PG&E's proposals better align our AG rate designs with the CPUC's rate design principles and achieve movement toward cost-of-service targets to reflect underlying distribution and generation marginal costs. Therefore, PG&E respectfully requests that the Commission approve all of its proposed AG rate design revisions.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

STREETLIGHTING RATE DESIGN

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
STREETLIGHTING RATE DESIGN

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
STREETLIGHTING RATE DESIGN

A. Introduction

This chapter presents Pacific Gas and Electric Company's (PG&E) 2023 General Rate Case Phase II (GRC II) rate design proposals for the Streetlight customer class, which consists primarily of cities, counties and other jurisdictions that provide lighting for streets, highways, bridges, parks, and other outdoor areas. Rate design for the Streetlight customer class includes rate components for transmission, distribution (including facility charges), generation, Public Purpose Programs (PPP), Competition Transition Charges, Nuclear Decommissioning, Wildfire Fund Charge, Wildfire Hardening Charge, Recovery Bond Charge, Recovery Bond Credit, New System Generation Charges, the Energy Cost Recovery Amount, and the Power Charge Indifference Adjustment. In this proceeding, PG&E is proposing changes to generation, distribution and PPP revenue allocation and rate design. PG&E is not making any proposals for revenue allocation and rate design for other components of streetlight rates. Accordingly, PG&E's current approach to revenue allocation and rate design for these components is set forth in Exhibit (PG&E-3), Chapter 1, "Introduction to Revenue Allocation and Rate Design." Generation, distribution, and PPP revenue allocation, as well as PPP rate design,[1] is described in Exhibit (PG&E-3), Chapter 2.

B. Summary of Proposals

PG&E's updates to streetlight rate design proposals for the Streetlight customer class are described in the following testimony and include adjustments to facility charge rates to reflect updated costs, as well as determination of the total monthly streetlight charges. Consistent with PG&E's Revenue Allocation proposal in Exhibit (PG&E-3), Chapter 2, PG&E's goal is to transition allocations to full cost of service over a period of four years. For customer classes that exceed a bundled rate increase of 8 percent, PG&E proposes to move

[1] PPP rates for the streetlighting customers are designed in accordance with the guidelines described in Chapter 1 using the revenue allocation provided in Chapter 2.

one-fourth of the way towards an 8 percent cap per year. Accordingly, PG&E proposes to adjust the facility charge one-fourth of the way towards an 8 percent cap of the full revenue requirement each year for the next four years following a final decision.

Table 6-1 below shows Streetlight Settlement Agreement (SA) items that were adopted in Decision (D.) 21-11-016 (2020 GRC II) and summarizes PG&E's proposal in this proceeding.

TABLE 6-1
SUMMARY OF ITEMS ADOPTED IN THE 2020 GRC II VS. PG&E'S PROPOSALS IN THIS PROCEEDING

Line No.	Applicable Schedule/Customer	2020 GRC II Adopted Rates and Programs via SA	2023 GRC II Proposed Changes
1	LS-3	No changes to LS-3	Increase LS-3's customer charge partially towards EPMC marginal customer costs
2	LS-1 LS-2 OL-1 City and County of San Francisco (CCSF)	One-time 1/12th to full cost adjustment to facility charges	Adjust facility charges one-fourth towards an 8 percent cap to full cost each year for the 4 years following a final decision.
3	LS-1 CCSF	Reduce the Decorative Incremental Facility Charges (IFC)	Not applicable – the Decorative IFC was eliminated in Advice 7190-E[(a)]
4	LS-1 OL-1 CCSF	Eliminate the Non-Decorative IFC	Not applicable
5	City of San Jose	Continue the Dimmable Streetlight Pilot program authorized in D.11-12-053	Continue as adopted
6	N/A	Eliminate the Dimmable Streetlight Pilot program authorized in D.15-08-005	Not applicable
7	N/A	Establish specific guiding principles for parties to use in developing potential new metered dimmable streetlights or ancillary device rates in the future.	No new rate design proposal for a dimmable streetlight rate – adopted principles were not met.

(a) The Commission adopted Advice 7190-E on February 29, 2024.

C. Organization of the Rest of This Chapter

The remainder of this chapter is organized as follows:

- Section D – Background;
- Section E – Non-Energy Facility Charge Calculation for Schedules LS-1, LS-2, OL-1, and CCSF Streetlights;
- Section F – Energy Charge and Total Streetlight Rates for Schedules LS-1, LS-2, and OL-1;
- Section G – Elimination of Rate Schedule LS-2C;
- Section H – Rate Design for Schedule LS-3;
- Section I – Network-Controlled Dimmable Streetlight; and
- Section J – Conclusion.

In addition, the following information regarding Streetlight rate design can be found in Exhibit (PG&E-4):

- Appendix C – Present and proposed total and unbundled rates for Streetlight rate schedules.

D. Background

In this chapter, PG&E addresses rate design for Schedules LS-1, LS-2, LS-3, OL-1, and CCSF streetlights. Schedules LS-1 and LS-2 provide options for illuminating public streets, highways, and other outdoor ways and places and are designed as a fixed monthly charge. Schedule OL-1 is also designed as a fixed charge per month for private outdoor lighting. PG&E also develops fixed monthly charges for CCSF's streetlights. Schedule LS-3, however, is a metered schedule with a customer charge and an energy rate that does not vary by time of day or season.

Schedules LS-1, LS-2, OL-1 and CCSF streetlights include a fixed monthly charge per lamp (facility charge) based on the most common type and size of lamp within each rate schedule and the type of service provided by PG&E (e.g., LS-1A, LS-1C, etc.). The monthly charge for Schedules LS-1, LS-2 and OL-1 consists of a non-energy facility portion and an energy portion based on the estimated usage per lamp and an average energy rate. The average energy rate includes all applicable components as set forth in Section A, above, and is derived in the process of developing the revenue allocation. The average energy rate is the same for Schedules LS-1, LS-2, LS-3 and OL-1, except that

Schedule OL-1 pays the full PPP charge.[2] A summary of the rate schedules that are addressed in this chapter is provided in the table below.

TABLE 6-2
SUMMARY OF STREETLIGHT SCHEDULES

Line No.	Streetlight Rate Schedule	Description	Fixed Charge	Full PPP Included in Energy Rate
1	LS-1	PG&E-Owned Public Street and Highway Lighting	Facility Charge	No
2	LS-2	Customer-Owned Public Street and Highway Lighting	Facility Charge	No
3	LS-3	Metered Customer-Owned Street and Highway Lighting	Customer Charge	No
4	OL-1	Private Outdoor Area Lighting	Facility Charge	Yes
5	CCSF	PG&E-Owned Public Street and Highway Lighting Operating in CCSF's Territory	Facility Charge	No

E. Non-Energy Facility Charge Calculation for Schedules LS-1, LS-2, OL-1, and CCSF Streetlights

In this proceeding, PG&E continues to base its non-energy facility charge proposal on the adopted non-energy streetlight rate design model. This model was first introduced in PG&E's 2003 GRC II[3] and has continued to be used in PG&E's GRC II proceedings since that time. The California Public Utilities Commission (CPUC or Commission) approved the Streetlight Non-Energy Charges set forth in the May 13, 2005, SA adopted in D.05-11-005. The method proposed herein was most recently adopted in the settlement approved by the CPUC in D.21-11-016 and is the basis for the currently-effective non-energy facility charges for these rate schedules.

Consistent with PG&E's Revenue Allocation proposal in Exhibit (PG&E-3), Chapter 2, PG&E proposes to transition allocations to full cost of service over a period of four years. For customer classes that exceed a bundled rate increase of 8 percent, PG&E proposes to move one-fourth of the way towards an

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2 Rates for Schedules LS-1, LS-2 and LS-3 do not include the California Alternate Rates for Energy (CARE) surcharge component of the PPP rate.

3 D.05-11-005, p. 33, Ordering Paragraph 1.

8 percent cap per year. Specifically, PG&E is proposing to adjust the streetlight facility charges one-fourth of the way towards an 8 percent cap of full cost each year for the 4 years following a final decision. PG&E's proposed facility rates capped at 8 percent towards full cost (that is, in year four of the transition) are provided in Table 6-7 at the end of this chapter.

The three components of the non-energy facility charge, using the model adopted in PG&E's 2020 GRC II, are:

- Universal Charge;
- Remaining operations and maintenance (O&M) Expense Charge; and
- Plant-Related Charge.

Table 6-3, below, provides a summary of the applicability of these non-energy facility charge components to each streetlight rate schedule.

TABLE 6-3
APPLICABILITY OF NON-ENERGY FACILITY CHARGE COMPONENTS

Line No.	Streetlight Rate Schedule	Universal Charge	O&M Charge	Plant-Related Charge
1	LS-1	Yes	Yes	Yes
2	LS-2A	Yes	No	No
3	LS-2C	Eliminated	Eliminated	Eliminated
4	OL-1	Yes	Yes	Yes
5	CCSF	Yes	Yes	Yes

1. Universal Charge

The Universal Charge is imposed on all LS-1, LS-2, OL-1, and CCSF streetlight customers regardless of whether the streetlight is owned by the customer or by PG&E. The Universal Charge covers recovery of O&M, Customer Accounts, and Administrative and General (A&G) expenses.

The O&M portion of the Universal Charge includes Distribution Maps and Records, as well as Supervision costs. The Customer Accounts portion of the Universal Charge includes the Streetlight Inventory Program. The A&G portion of the Universal Charge is calculated by multiplying the test year (TY) electric distribution A&G loader by the O&M expense.

a. O&M Expense

For its proposed streetlight rates, PG&E uses 2020 actual costs and 2023 TY estimates for the streetlight O&M account,[4] shown in the Federal Energy Regulatory Commission (FERC) Account 596 (Distribution Maintenance of Streetlights and Signal Systems).

As done in prior GRC II proceedings (beginning with PG&E's 2007 GRC II), PG&E continues to separate the O&M streetlight expenses into the Universal Charge (Distribution Maps and Records, and Supervision) and the Remaining O&M Expense Charge (group replacements and burnouts). However, Supervision costs are no longer included in FERC Account 596. Instead, PG&E uses 2020 actual Supervision costs escalated to 2023 dollars. This separation enables PG&E to unbundle the expense for group lamp replacements and burnouts.

b. Customer Accounts Expense

Similar to the 2020 GRC II, in this 2023 GRC II, PG&E proposes to include the Streetlight Inventory Program cost in the Universal Charge. This cost is specifically related to the lamp inventory for Schedules LS-1, LS-2, and OL-1, and is driven by record keeping for each streetlight in the streetlight inventory.

c. A&G Expenses

For this 2023 GRC II, PG&E proposes to continue to calculate the A&G expenses by multiplying the TY electric distribution A&G loader by the O&M expenses in the Universal Charge.[5] The electric distribution A&G loader for this 2023 GRC II, is equal to 8.81 percent, as described in Exhibit (PG&E-2), Chapter 9, "Marginal Cost Loaders and Financial Factors."

2. Remaining O&M Expense Charge

O&M expenses that were not incorporated into the Universal Charge, such as group replacement and burnouts, appear in the Remaining O&M Expense Charge. For this 2023 GRC II, PG&E proposes to continue to

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[4] Consistent with PG&E's 2023 GRC Phase I adopted in D.23-11-069.

[5] A&G Loader is already embedded within the customer account expenses portion of the Universal Charge.

calculate the remaining O&M expenses for this component by applying the TY electric distribution A&G loader discussed in the previous paragraph.

3. Plant-Related Charge

The Plant-Related charge is developed first by determining the revenue requirement for the capital cost of the streetlights and then separately determining the replacement cost for each type of lamp in order to allocate the revenue requirement among all lamp types in Schedules LS-1, OL-1, and CCSF streetlights.

a. Plant Revenue Requirements

The Plant-Related charge is based on a revenue requirement that is derived using the year-end balances of the streetlight plant accounts. The revenue requirement is based on the cost of owning the streetlight facilities for Schedules LS-1, OL-1, and CCSF and includes costs for depreciation, uncollectibles, franchise fees, income taxes, property taxes and return. In this proceeding, PG&E is proposing to collect the revenue requirement in the Plant-Related charge, reallocate that revenue to reflect updated replacement costs and reflect a change to the "most common lamp type" as discussed in more detail below.

b. Replacement Costs

The revenue requirement is allocated to each streetlight rate schedule according to the replacement cost of each lamp type. There are four basic lamp types currently in use on PG&E's system: (1) High Pressure Sodium Vapor (HPSV); (2) Mercury Vapor (MV); (3) incandescent; and (4) newer technologies like light emitting diode (LED) street lamps, which is the most common streetlight lamp type.

For this 2023 GRC II, PG&E updates the streetlight replacement cost on most lamp types with July 2024 data, which was the most up-to-date data available at the time this testimony was prepared. PG&E continues to use the materials and labor categories that were used to determine the rates in the Streetlight Rate Design Settlement adopted in D.21-11-016.[6] MV, incandescent, and HPSV lamps are old, obsolete technologies that are not supported by manufacturers and/or for which spare parts/supplies are no longer available or more expensive than LED. Therefore, as these lamps fail or burn out, the luminaire (and not just the lamp itself) is replaced by an LED luminaire with the equivalent number of lumens. As a result, PG&E derived the replacement cost for these obsolete lamps based on the replacement cost for LED lamps with the equivalent number of lumens.[7]

c. Plant Revenue Requirement Allocation

Once the total replacement costs are determined, the Plant Revenue Requirement, or in this case the total current Plant-Related facility charge revenue, is allocated to each lamp type in a three -step process. First, PG&E calculates the Revenue Allocation Factors (RAF), which is the ratio of the embedded revenue requirements compared to the total replacement costs for all lamps under Schedules LS-1, OL-1, and CCSF.[8] Second, PG&E multiplies the RAF by the replacement cost on each of the most common lamp type in Schedules LS-1, OL-1, and CCSF to yield an annualized Plant-Related charge rate. Lastly, the annualized charge rates are then scaled to equal to the total required revenue.

F. Energy Charge and Total Streetlight Rates for Schedules LS-1, LS-2, and OL-1

The total monthly charge per lamp for Schedules LS-1, LS-2, and OL-1 is the sum of the non-energy facility charge and the product of the energy usage per lamp and a volumetric (per kilowatt-hour (kWh)) rate which includes all other costs allocated to these customers. Since Schedules LS-1, LS-2, and OL-1 are not metered, energy usage for these rate schedules is derived based on the type

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6 PG&E obtained the cost data for materials and labor (e.g., for each lamp type) to install the replacement lamp from standard estimating tools that are routinely used in most construction projects.

7 MV, incandescent, and HPSV lamps make up less than 30,000 of the approximately 197,350 PG&E-owned streetlights encompassed by the Plant-Related Charge.

8 Embedded revenue requirements include plant (direct rate base only) revenue requirements, uncollectibles, and franchise requirements.

and size of lamp and lamp ballast, and the estimated number of hours during which the lamp would operate each month. For this GRC II, PG&E proposes no change in the estimated hours of operation. Lamps are assumed to be operated for approximately 11 hours per night on average, but not to exceed 4,100 hours per year for all-night rates.

The volumetric energy rate is determined by subtracting non-energy facility charge revenues from Schedules LS-1, LS-2, OL-1, and CCSF lamps, as well as the applicable Schedule LS-3 customer charge from the total revenue allocated to the streetlight class, and then dividing the difference by the applicable sales, in kWh. The energy rate is the same for Schedules LS-1, LS-2, LS-3, and OL-1, except that Schedule OL-1 pays the full PPP charge.

G. Elimination of Rate Schedule LS-2C

PG&E proposes to eliminate Schedule LS-2C because the schedule is closed to new customers and there are no existing customers currently enrolled.[9]

H. Rate Design for LS-3

As noted in the Background section of this testimony, Schedule LS-3 includes a customer charge and an energy rate that does not vary by season or by time of use. PG&E proposes to increase the LS-3 customer charge, see Table 6-4 below, from $7.50 per month to $11.00 per month (expressed on a daily equivalent basis) to better reflect the cost of service.[10] The selection of a $3.50 increase is further supported by the inflation rates since the current fixed charge was proposed in 2016. Based on the California Consumer Price Index from 2016 to 2023,[11] combined with an estimated 3 percent annual inflation from 2024 to 2027, when the rate proposed in this proceeding is anticipated to

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9 On May 24, 2021, the Commission approved Advice Letter 6169-E, which, among other things, approved tariff modifications to transition existing LS-2C customers to LS-2A and close LS-2C.

10 The Customer Charge for Schedule LS-3 was last revised by the CPUC in D.18-08-013 (PG&E's 2017 GRC II proceeding). The fully scaled cost uses an equal percentage of marginal cost scalar of 3.41.

11 California Department of Industrial Relations, California Consumer Price Index, available at: <https://www.dir.ca.gov/OPRL/CPI/EntireCCPI.PDF> (accessed Sept. 12, 2024).

be implemented, the customer charge reaches to approximately $11, as illustrated in Table 6-5 below.

TABLE 6-4
LS-3 PROPOSED MONTHLY CUSTOMER CHARGE LEVELS

Line No.	Current	Proposed	At Cost	Fully Scaled Cost
1	$7.50	$11.00	$4.57	$20.17

TABLE 6-5
CALIFORNIA CONSUMER PRICE INDEX
2016-2023 HISTORICAL DATA, AND 2024-2027 FORECAST

Line No.	Year	CPI	Inflation	LS-3 Customer Charge
1	2016	255.303	–	$7.50
2	2017	262.802	2.9%	$7.72
3	2018	272.51	3.7%	$8.01
4	2019	280.638	3.0%	$8.24
5	2020	285.315	1.7%	$8.38
6	2021	297.371	4.2%	$8.74
7	2022	319.224	7.3%	$9.38
8	2023	331.804	3.9%	$9.75
9	2024	–	3%	$10.04
10	2025	–	3%	$10.34
11	2026	–	3%	$10.65
12	2027	–	3%	$10.97

I. Network-Controlled Dimmable Streetlight

1. Pilot Program

A Pilot Program for Network-Controlled Dimmable Streetlights (Pilot) was established as part of the Streetlight SA approved by the CPUC in PG&E's 2011 GRC II (D.11-12-053).[12] The Pilot was revised in the Streetlight SA approved by the CPUC in PG&E's 2014 GRC II.[13] As

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12 See D.11-12-053, pp. 55-58, adopting, without modification, the uncontested Amended Streetlight SA attached to that decision as Appendix D, Attachment 3. See also Resolution E-4421 approving the necessary Special Contract that would allowing participants' billing to deviate from PG&E's existing LS-2 streetlight rate schedule, to allow for reductions due to dimmable LED streetlights under this pilot.

13 See A.13-04-012, Motion of Settlement Parties for Adoption of Streetlight Rate Design Supplemental SA, Including a Revised 2014 Dimmable Streetlight Pilot Program (Aug. 29, 2014), Attachment, p. 5, approved by D.15-08-005.

compared with the 2011 Dimmable Pilot Program, which is now closed to new enrollment, the 2014 Dimmable Pilot Program was expected to provide dimmable streetlight service as an option to Schedule LS-2 that was simpler and offered participants some certainty that they would benefit from related energy savings in a timely and mutually-workable way. The 2014 Dimmable Streetlight Pilot Program did not have any participating customers and was eliminated in D.21-11-016.[14] To date, there is only one participant in the 2011 pilot – the City of San Jose.

In the 2017 GRC II proceeding, the Commission adopted the Streetlight Rate Design Settlement as part of D.18-08-013. Among other things, the SA required that PG&E hold a workshop to discuss the feasibility of a fully-automated, dimmable streetlight and ancillary device billing system. In addition, the settlement required that PG&E develop a report including a work plan and cost estimate for such a system and include the report in Phase I of the 2020 GRC. Accordingly, the Compliance Report was filed in Phase I of the 2020 GRC proceeding.[15] As part of the Compliance Report, PG&E stated that it:

> …does not recommend the Commission pursue a fully integrated metering and billing option for dimmable streetlights at this time in light of the relative costs to both customer and to PG&E.[16]

In that same proceeding, California City-County Street Light Association (CALSLA) recommended that the Commission approve a fully-integrated billing and metering solution for dimmable streetlights that utilized customer-owned meters.[17]

In its Rebuttal Testimony, PG&E expanded on why the Commission should not approve a fully-automated billing and metering at this time. First, whether the meters would be customer-owned or owned by PG&E, the Information Technology costs of the programs would be considerable and

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14 See A.19-11-019, PG&E's Motion for Adoption of Streetlight Rate Design Settlement Agreement (Feb. 23, 2021), Attachment 1, approved in D.21-11-016, p. 8.

15 A.18-12-009, Hearing Exhibit (HE) 74 (PG&E-7), WP 8-163 to WP 8-188.

16 A.18-12-009, HE 74 (PG&E-7), WP 8-169 to WP 8-170; HE 70 (PG&E-26), pp. 9-4, lines 14-22.

17 A.18-12-009, HE 28 (CALSLA-01), p. 1, lines 21-24; p. 9, line 27 to p. 10, line 9.

the potential costs that would be incurred by customers to achieve the desired benefit are uncertain. The pilot program has demonstrated that for a subset of pilot locations, the concept of utilizing measured usage to calculate an energy credit for dimming was valid. However, the pilot has not provided an adequate demonstration that customer-owned meters and data delivery systems are capable of providing the information to PG&E that is necessary billing in a timely and complete manner.[18] PG&E proposes to continue the pilot program for the City of San Jose. Continuing the pilot program would provide, at a minimum, benefits of a basic dimming schedule while offering an opportunity for them to improve the capability of their systems and reduce/receive a credit on their total bills.

2. Rate Design for a Fully-Integrated Metered and Billing Solution for Dimmable Streetlights

In the 2020 GRC II Streetlight SA, the Settling Parties agreed that a new fully automated dimmable street light metering system is unlikely to be used by customers or provide benefit in the near-term. The City of San Jose, the only customer enrolled in the Dimmable Streetlight Pilot Program, has faced technological and administrative difficulties. The dimmable metering and data delivery systems currently deployed by San Jose are an older generation of the technology that is still undergoing the validation and auditing process required by the Pilot Program. San Jose continues working to maximize the capabilities of its current metering system but did not meet the requirements of a fully automated rate at that time. As a result, CALSLA agreed to withdraw its proposal for such a rate in the proceeding, without prejudice. The Streetlight Settling Parties affirmatively agreed that new metered rates should not be approved by the Commission at that time. Instead, the Parties established principles and defined triggers, as shown below in Table 6-6, to ensure that a metered rate for dimmable streetlights can be made available in the future when appropriate.[19]

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[18] A.18-12-009, HE 70 (PG&E-28), pp. 9-6, line 8 to pp. 9-7, line 13.

[19] A.19-11-019, PG&E's Motion for Adoption of Streetlight Rate Design Settlement Agreement (Feb. 23, 2021), Attachment 1, approved in D.21-11-016, pp. 9-11.

TABLE 6-6
ASSESSMENT OF DIMMABLE STREETLIGHT PILOT TRIGGER STATUS

Line No.	Adopted Dimmable Streetlight Pilot Triggers	Status
1	a. The trigger for beginning development of and making proposals for any metered rate for dimmable streetlights that uses customer-owned meters will be satisfied when a customer has provided six (6) consecutive months of data that is deemed by PG&E to be compliant with the metering and data delivery requirements set forth in Rule 22 Standards for Meter Service Providers and Meter Data Management Agents.	The participant has not met the Rule 22 requirements for meter data submission.[a] On average, the meter read data provided by the participant in the pilot has provided 94.5 percent of recorders with delivered reads, however only 24.3 percent of meters provided a read which was usable for dimming credit calculation. The balance of the reads either indicated that zero usage or a fractional kWh value had elapsed during the read period for an active streetlight, or provided a read which indicated usage exceeding that which would have otherwise been charged under the Schedule LS-2 tariff. The last read file provided by participant to PG&E was for service through August 2020.
2	b. Once the above-defined trigger for beginning development of and making proposals for a metered rate for dimmable streetlights using customer-owned meters has been satisfied, PG&E will work with CALSLA to identify and confirm a rate design proceeding to be used for that purpose which could be either a GRC II proceeding or a Rate Design Window proceeding. Eligibility for any such rate would require a customer first satisfy all requirements to be a Meter Service Provider and Meter Data Management Agent as required by Rule 22, and be similarly required to demonstrate their ability to provide six (6) [consecutive] months of data that is deemed by PG&E to be compliant with the metering and data delivery requirements set forth in Rule 22 Standards for Meter Service Providers and Meter Data Management Agents. Parties may make proposals for a dimmable streetlight rates as they feel appropriate at the time. Potential future such rate proposals in any PG&E rate design proceeding may include the overall expected cost, cost recovery from participants compared to the general body of ratepayers, application of the Per Meter Charge (PMC), implementation plan, as well as rate design for the new rate.	The initial trigger above has not been met—this trigger is unfulfilled.

TABLE 6-6
ASSESSMENT OF DIMMABLE STREETLIGHT PILOT TRIGGER STATUS
(CONTINUED)

Line No.	Adopted Dimmable Streetlight Pilot Triggers	Status
3	c. If the trigger is satisfied, and such a rate proposal or proposals have been litigated and approved such a new rate, for dimmable streetlights using customer owned meters, PG&E will initiate the process of implementing that rate as soon as practicable. The necessary structural and system changes would be implemented by PG&E as diligently and expeditiously as possible, in a manner consistent with smooth operation of the systems involved. The Streetlight Settling Parties understand that constraints may result in an extended implementation period. The Streetlight Settling Parties agree that, any future such proposal shall include a request that PG&E be permitted to establish a memorandum account to track any implementation costs related to a Dimmable Streetlight Program that are incurred, and to seek recovery of those costs in Phase 1 of a GRC or in a separate application. The Streetlight Settling Parties shall support full recovery of PG&E's actual costs.	The initial trigger above has not been met—this trigger is unfulfilled.
4	d. Finally, CALSLA noted there may potentially be interest in a pilot for ancillary devices on dimmable streetlights in the future. The Streetlight Settling Parties agree that a pilot approach would be needed to prove out the technology, as has been being done and will be continuing for the dimmable streetlights technology. The Streetlight Settling Parties are open to discussing a distinct pilot to prove out such added technologies, but agree that it is premature to attempt to design an ancillary devices pilot at this time. The reason it is premature at this time is not only that there is currently no specific customer demand or impending deployment of such devices, but also that there is not an adequate enough understanding of the technology(ies) to be used to allow design of such an ancillary devices pilot to begin at this time. PG&E and CALSLA agree to meet and confer about such a potential ancillary devices pilot when enough is known about the technology to consider what pilot options or approaches might be warranted. As a result, CALSLA agrees to withdraw its proposal for an ancillary devices rate in this proceeding, without prejudice to the merits and feasibility of such a rate pilot potentially being considered in a future.	The initial trigger above has not been met—this trigger is unfulfilled.

(a) Rule 22 Direct Access Standards for Metering and Meter Data (DASMMD) Schedule C, Section VI (b) requires third parties to submit meter read data to PG&E by no later than the 5th working day following the scheduled meter reading date, and with no more than 10 percent of accounts with any missing data, or 1 percent of accounts with estimation (in place of actual reads).

As described above, PG&E's assessment of each of the triggers, as of August 2024, showed that none of the triggers have been met, therefore PG&E does not propose to create a new rate design for fully automated dimmable streetlights in this proceeding. Additionally, PG&E proposes to continue to adhere to the guiding principles and triggers defined in the Streetlight SA to ensure that a metered rate for dimmable streetlights can be made in the future at an appropriate time.

J. Conclusion

PG&E requests that the Commission adopt its: (1) proposed rate design for non-energy facility charges for Schedules LS-1, LS-2, OL-1, and CCSF streetlights; (2) proposed energy charges for all streetlight rate schedules; (3) elimination of Schedule LS-2C; (4) proposed increase to LS-3's customer charge; (5) continuance of the Dimmable Streetlight Pilot Program; (6) continuing the existing rate design for fully automated dimmable streetlights; and (7) continuing to adhere to the 2020 GRC II Streetlight SA's guiding principles and triggers for proposing a new rate design for dimmable streetlights.

TABLE 6-7
FACILITY CHARGES FOR STREETLIGHT RATES

			Lamp Counts			Monthly Rate				Annual Revenues - Proposed ($000)	
	Rate Schedule	Service	Plant Charge	Universal Charge	O&M Charge	Plant Charge	Universal Charge	O&M Charge	Total Monthly Facility Charge	Per Schedule	Per Class
1	LS-1A	PG&E owns and maintains luminaire, control facilities, support arm, and service wiring on its existing distribution pole, and all lights. Most common lamp type: LED 34W.	62,385	62,385	62,385	$3.978	$0.191	$3.354	$7.523	$ 5,632	
2	LS-1B	PG&E owns and maintains luminaire, control facilities, support arm, pole or post, foundation and service connection and where customer has paid the estimated installed cost of the luminaire, support arm and control facilities. Most common lamp type: MV 175W (HPSV 70W equivalent).	13	13	13	$4.276	$0.191	$3.354	$7.821	$ 1	
3	LS-1C	PG&E owns and maintains its standard luminaire, control facility, internal pole wiring as required. (Ownership of pole or post, support arm and foundation by customer where light is the only light on a pole or where this schedule is applied to all lights on the customer owned pole. Also applies to second and all multiple lights on poles or posts owned by PG&E. Most common lamp type: LED 34W.	19,306	19,306	19,306	$3.101	$0.191	$3.354	$6.646	$ 1,540	
4	LS-1D	PG&E owns and maintains its standard post top luminaire, control facility, internal post wiring, standard galvanized steel post (20-foot mounting height or less) and foundation where customer pays for the estimated and installed cost of the post, support arm (if any) and foundation. Most common lamp type: HPSV 70W.	21,281	21,281	21,281	$6.085	$0.191	$3.354	$9.630	$ 2,459	
5	LS-1E	PG&E owns and maintains its standard luminaire, control facility, internal pole wiring, service connection, galvanized steel pole and foundation where the customer has paid to PG&E the estimated installed cost of the pole, support arm and foundation. Most common lamp type: LED 34W.	44,375	44,375	44,375	$6.274	$0.191	$3.354	$9.819	$ 5,229	
6	LS-1F	PG&E owns and maintains a standard luminaire, control facility, support arm, and service connection on its standard pole or post, installed solely for the luminaire. Most common lamp type: LED 34W.	16,465	16,465	16,465	$4.854	$0.191	$3.354	$8.399	$ 1,659	$ 16,521
7	LS-2A	City Owned and Maintained		646,841			$0.191		$0.191	$ 1,480	
8	OL-1	Outdoor area lighting service where street lighting schedules are not applicable and where PG&E installs, owns, operates and maintains the complete lighting installation on PG&E's existing wood distribution poles or on customer-owned poles acceptable to PG&E installed by the customer on his private property. Most common lamp type: LED 34W.	15,578	15,578	15,578	$4.273	$0.191	$3.354	$7.818	$ 1,462	$1,462
9	CCSF Standard:										
10		CCSF Rate Schedule No. 1 (LS-1A LED 53W)	15,259	15,259	15,259	$4.289	$0.191	$3.354	$7.834	$ 1,434	
11		CCSF Rate Schedule No. 3 (LS-1A HPSV 150W)	19	19	19	$3.994	$0.191	$3.354	$7.539	$ 2	
12		CCSF Rate Schedule No. 4E (LS-1E LED 53W)	1,508	1,508	1,508	$6.542	$0.191	$3.354	$10.087	$ 183	
13	CCSF Non-Standard										
14		CCSF Rate Schedule No. 4A:									
15		Incandescent 405W	6	6	6	$22.111	$0.191	$3.354	$25.656	$ 2	
16		CCSF Rate Schedule No. 5:									
17		HPSV 100W	694	694	694	$9.511	$0.191	$3.354	$13.056	$ 109	
18		Incandescent 405W	10	10	10	$22.111	$0.191	$3.354	$25.656	$ 3	
19		CCSF Rate Schedule No. 6A (Chinatown Area) - HSPV 250W	43	43	43	$60.184	$0.191	$3.354	$63.729	$ 33	
20		CCSF Rate Schedule No. 9 (Triangle District)									
21		HPSV:									
22		150W 16,000 LUMENS DUPLEX (1)	192	192	192	$61.641	$0.191	$3.354	$65.186	$ 150	
23		150W 16,000 LUMENS DUPLEX (2)	192	192	192	$1.326	$0.191	$3.354	$4.871	$ 11	
24	CCSF Subtotal		17,923	17,923	17,923	$5.413	$0.191	$3.354	$8.958	$ 1,927	$ 1,927
25	Lamp Count Totals		197,326	844,166	197,326						
26	Annual Revenues ($000)		$11,514	$1,931	$7,943					$ 21,388	$19,909

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 7

BUSINESS ELECTRIC VEHICLES RATE DESIGN

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
BUSINESS ELECTRIC VEHICLES RATE DESIGN

A. Introduction [Witness: Oriana Tiell]

This chapter presents Pacific Gas and Electric Company's (PG&E or the Utility) rates for customers in the Business Electric Vehicle (BEV) class who take service on Schedules BEV-1 and BEV-2. In Decision (D.) 19-10-055, the California Public Utilities Commission (CPUC or Commission) approved PG&E's application for a new opt-in rate, originally referred to as Commercial Electric Vehicle (CEV) rate.[1] As non-residential electric vehicle charging is applicable to additional customer classes besides commercial customers, PG&E redefined the customer base and refers to this new customer class as the Business Electric Vehicle (BEV) class.

In this chapter, PG&E describes its proposals for generation and distribution rate design for BEV customers. Public Purpose Program (PPP) rates for BEV customers are described in Chapter 2 of this exhibit.

Discussion of the real-time pricing (RTP) rate approved in D.21-11-017[2] for BEV customers is in Chapter 10 of this exhibit. In D.22-10-024, the Commission approved a Non-Net Energy Metering (NEM) export compensation pilot that is available to BEV customers who take service on the Day-Ahead Hourly Real Time Pricing (DAHRTP) rate.[3] The Non-NEM export compensation pilot rate is also discussed in Chapter 10.

B. Summary of Proposals [Witness: Tysen Streib]

PG&E is not proposing any structural changes to BEV rate design. Instead, PG&E proposes updating: (1) both distribution and generation rates to better reflect cost of service, based on the revenue allocation to classes in this proceeding, and (2) the method for adjusting rates for revenue requirement changes.

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1 D.19-10-055, p. 73, Ordering Paragraph (OP) 1.

2 D.21-11-017, p. 54, OP 1.

3 D.22-10-024, p. 15, OP 1 and Attachment A.

TABLE 7-1
SUMMARY OF PROPOSALS IN THIS CHAPTER

Line No	Feature	As Adopted by the CPUC in D.19-10-055	Summary of Changes Proposed in This General Rate Case Phase II (GRC II) Proceeding	Discussed in Section
1	BEV subscription rate	Set to 2017 proxy estimates of marginal cost.	Reflect actual marginal costs into rates, as follows: BEV-1: Vary the subscription rate gradually by taking half of the percentage increase to distribution revenue and applying that to the subscription (i.e., if distribution revenues increase 10 percent then increase the subscription by 5 percent). BEV-2: Allocate revenue to the subscription charge in proportion to the marginal costs that are customer related or non-coincident (i.e., Customer and Secondary Capacity marginal costs).	E.1
2	Distribution energy rates	Set to 2017 proxy estimates of marginal cost.	Set time-of-use (TOU) differences equal to the average of current differences and the differences from 2023 marginal costs. Collect all remaining distribution revenue not collected by subscription.	E.1
3	Generation energy rates	Set peak rate to be higher than marginal cost differences.	Set TOU differences equal to the average of current differences and the differences from 2023 marginal costs. Collect all generation revenue.	E.2

In addition, PG&E recommends extending the BEV performance reporting required by D.19-10-055 by another 3 years.

C. Organization of the Rest of This Chapter and Witness Responsibilities

The remainder of this chapter is organized as follows:

- Section D – Background;
- Section E – BEV Rate Change Proposals; and
- Section F – Conclusion.

In addition, the present and proposed rates for all BEV schedules can be found in Exhibit (PG&E-4), Appendix C.

The witness responsibilities for this chapter are as follows:

- Oriana Tiell – All sections of this chapter with the exception of those noted below.
- Tysen Streib – Sections B (Summary of Proposals) and E (BEV Rate Change Proposals).

D. Background [Witness: Oriana Tiell]

1. Overview

The BEV Class was created in D.19-10-055 and PG&E started offering the new BEV[4] rate in May 2020. Today, BEV customers self-select[5] into five different use-case categories based on their Electric Vehicle (EV) charging load: (1) Direct Current Fast Chargers (DCFC) open to the public, (2) Public Transit (Transit), (3) Workplace, (4) Medium-Duty Fleets (Fleet), and (5) Multi-family Housing (MFH). All BEV customers have EV charging stations; some BEV customers service EV fleets while others offer charging services to the public and can charge their end users at their discretion.

Customers on BEV rates have a choice of BEV subscription block levels (BEV subscription),[6] described below, based on their charging needs:

- Business Low Use EV Rate – BEV-1: For EV charging installations up to and including 100 kilowatts (kW). Best suited for Workplaces and MFH.
- Business High Use EV Rate – BEV-2: For EV charging installations of 100 kW and above. Best suited for sites with Fleets, Transit and DCFC stations.

Both plans combine customizable monthly BEV subscription charges with a TOU energy rate. The key components of the BEV rates are:

- Monthly BEV Subscription Charge: The BEV subscription charge is unique to the BEV class and takes the place of traditional customer and demand charges. BEV-1 customers can choose a subscription level in blocks of 10 kW and BEV-2 customers can choose a subscription level

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4 Electric Schedule BEV, available at: <https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_BEV.pdf> (accessed on Sept. 5, 2024).

5 Customers who do not self-select into one of the five use cases are assigned the appropriate use case category as a part of the quality assurance post-processing using the combination of the publicly-available data such as PlugShare, available at: <https://www.plugshare.com/> and Google Maps, available at: <https://www.google.com/maps>, as well as input from customer service representatives and transportation electrification (TE) program managers. The categories are listed in D.19-10-055, pp. 12-13, Section 3.2.

6 The BEV subscription block in Schedules BEV-1 and BEV-2 is different from the subscription element in PG&E's RTP proposal, which is presented in Chapter 10 of this exhibit (PG&E-3).

in blocks of 50 kW, based on their maximum monthly EV charging kW demand. Customers can adjust the subscription level throughout the month as often as they want—until the last day of each billing cycle—for the entire applicable cycle and thereafter.

- Overage Fees: At the end of a billing cycle, if actual consumption (kW) exceeds the BEV subscription level, an overage fee (equal to two times the BEV subscription cost of one kW) will be charged for each kilowatt (kW) over the BEV subscription level. Customers have a grace period with no overage fees for three billing cycles after initial enrollment. A grace period also applies if customers add new charging infrastructure.
- Time-of-Use Rate: In addition to a monthly BEV subscription charge, customers are charged a volumetric energy rate (per kWh) based on energy usage during each TOU period. TOU period definitions are the same everyday year-round with no seasonality in the TOU energy charges. Time of use periods are defined as follows:

TABLE 7-2
TIME-OF-USE PERIOD DEFINITIONS FOR BEV SCHEDULES

Line No.	TOU Period	Times	Days
1	Peak	4:00 p.m. to 9:00 p.m.	Every day including weekends and holidays, all year.
2	Off Peak	9:00 p.m. to 9:00 a.m. and 2:00 p.m. to 4:00 p.m.	Every day including weekends and holidays, all year.
3	Super Off Peak	9:00 a.m. to 2:00 p.m.	Every day including weekends and holidays, all year.

As authorized in D.19-10-055, PG&E offers two EV rate plans for non-residential customers with on-site EV charging, Business Low Use EV Rate (BEV-1) and Business Hi Use EV Rate (BEV-2).[7] These rates were originally designed for customers with separately metered EV charging at locations. In D.22-08-024, the Commission introduced the submetering protocol in which any PG&E customer may enroll on an applicable EV rate

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7 D.19-10-055, p. 73, OP 3 for Schedule CEV-S and OP 4 for Schedule CEV-L. Note that Schedule CEV-L has been rebranded to BEV-1 and CEV-S to BEV-2.

for their EV charging.[8] Specifically, non-residential customers with EV charging may enroll on a BEV rate for their EV charging. EV submetering is the process of measuring customer's EV charging through a submeter, distinguishing customer's EV charging from other loads on the same service premise. An EV submeter can be an EV charging equipment with a submeter inside of it, or a standalone unit that can exist external to the EV charging equipment. The EV submeter measures and stores EV charging data for billing purposes. Customers enrolled in EV submetering receive a bill that reflects EV charging costs on BEV rate and remaining site load on the customer's other applicable tariff.

2. Reporting

As required in D.19-10-055, PG&E has submitted three of the four required annual reports on BEV rate performance as Tier 1 advice letters.[9] The most recent report was filed as Advice Letter (AL) 7557-E[10] on April 1, 2025,which was the fourth and final required report. As BEV rates continue to be of interest from the large group of stakeholders and given the current state of BEV customer adoption, PG&E recommends extending the reporting requirement for another three years until 2028.

3. Adoption

As of July 25, 2024, there is a total of 209 customers enrolled in a BEV rate with 826 service premises. The majority of BEV customers provide DCFC service to their EV end users. The DCFC BEV customers account for 90 percent of the total load for this customer class. Customers who have opted into the BEV rate tend to be clustered in and around the Bay Area and highly correlated to locations with high EV penetration. Approximately 70 percent of BEV customers take their generation service from Community Choice Aggregators, who are responsible for providing the energy supply

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8 D.22-08-024, p. 43, OP 1 and Attachment A.

9 D.19-10-055, p. 77, OP 16.

10 AL 75572-E, filed April 1, 2025, available at: <https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_7557-E.pdf> (accessed on Oct. 21, 2025).

and generation charges to the unbundled BEV customers. For additional information on adoption, please consult the BEV Performance Report.[11]

E. BEV Rate Change Proposals [Witness: Tysen Streib]

1. Distribution Rate Design

Schedules BEV-1 and BEV-2 have identical rate structures; they both have a BEV subscription charge and energy charges as described in Section D above. The only differences between the two schedules are: (1) the size of the BEV subscription blocks, and (2) the individual rate values. BEV-2 also has different rate values for customers depending on the voltage at which they take service (BEV-2S for those at secondary voltage and BEV-2P for those at primary voltage). PG&E currently only has a handful of BEV-2P customers, and they have very limited usage histories. Consequently, PG&E has not developed separate billing determinants for this schedule. Instead, PG&E designed rates for BEV-2P using BEV-2S billing determinants but applied only the applicable marginal cost components for primary customers.[12]

Under D.19-10-055, PG&E bases its current BEV rates on 2017 GRC II marginal costs that were estimated using the benchmark rate classes.[13] This is the first GRC where PG&E studied marginal costs for the BEV customer class. As a result, the marginal costs in this case are quite different and typically much higher than the 2017 benchmark estimates.

In addition, the Commission in D.19-10-055 instructed PG&E to keep distribution rates at marginal cost levels until this GRC.[14] This was a deliberate discount provided to encourage early adoption of the rate by customers, but this discount was not intended to last indefinitely.[15] These 2017 outdated marginal cost estimates were inaccurate for BEV-1, and the

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11 *Ibid*.

12 The marginal costs for the BEV-2 P customers are calculated by removing the secondary distribution marginal cost components from the BEV-2 S marginal costs.

13 BEV-1 was benchmarked with customers on the A-6 schedule, while BEV-2 was benchmarked with E-19. See Application (A.)18-11-003, PG&E's Amended Prepared Testimony (Feb. 26, 2019), pp. 2-2 to 2-11.

14 D.19-10-055, pp. 44-46.

15 *Id.* at pp. 45-46.

current marginal costs are more than double the rate levels set in D.19-10-055.[16] Present rate BEV-1 distribution revenues are only 40 percent of their marginal cost levels and only 21 percent of the distribution revenue requirement BEV-1 customers should contribute at their full cost of service. The level of this discount has made the BEV-1 schedule overly subsidized compared to other electric schedules and has likely led to their yielding a negative contribution to margin and cost-shifting to other classes. The level of the discount in BEV-2 is slightly better, but still collecting slightly less than current marginal costs, and far below the typical revenue requirement for other classes. Because BEV distribution rates have been frozen, BEV customers to date have not been paying for any of the increased wildfire and system hardening expenses that have substantially increased distribution revenue requirements over the last several years. Table 7-3 presents these revenue numbers for BEV-1 and BEV-2.

TABLE 7-3
PRESENT DISTRIBUTION REVENUES, MARGINAL COSTS, AND FULL COST REVENUES

Line No.		BEV-1	BEV-2
1	Present Revenue	$2,016,731	$12,626,960
2	Marginal Cost Revenue	$4,984,475	$14,241,296
3	Full Cost (Typical) Revenue	$9,528,203	$59,400,230

The BEV subscription rate component substitutes for traditional customer and non-coincident demand charges. Therefore, the applicable marginal costs for designing the BEV subscription are the Marginal Customer Costs, the Marginal Line Extension Costs (MLEC), and the Secondary Capacity Costs (when applicable). The energy rates are informed by the Primary Capacity Costs, which also determines the cent-per-kWh energy charge differentials between TOU periods.

Using the cost-based method for determining customer charges as described in Chapter 1, (i.e., Equal Percent of Marginal Cost (EPMC) scaling) the fixed costs associated with the Marginal Customer Cost should

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16 *Id.* at pp. 44-46.

also be included. Therefore, the revenues for the BEV subscription charge should include the revenues that would normally be assigned to a customer charge (EPMC-scaled customer costs) plus the revenues from non-coincident demand charges (Marginal Line Extension and Secondary Capacity Costs, unscaled). These costs are summarized in Table 7-4.

TABLE 7-4
MARGINAL COST REVENUES AND FULL COST BEV SUBSCRIPTION RATES

Line No.		BEV-1	BEV-2 S	BEV-2 P (Using Secondary Billing Determinants)
A	Secondary Capacity	$263,144	$954,089	–
B	Customer	3,630,888	4,045,970	$4,045,970
C	Marginal-Only BEV Subscription Revenues (A+B)	$3,894,033	$5,000,059	$4,045,970
D	EPMC Revenues for Customer Costs (3.41 - 1) * B	8,757,133	9,758,246	$9,758,246
E	Full-Cost BEV Subscription Revenues (C+D)	$12,651,166	$14,758,304	$13,804,216
F	Block Size (kW)	10	50	50
G	Forecasted Number of Blocks	105,639	88,070	88,070
H	Marginal-Only Subscription ($/block) (C/G)	$36.86	$56.77	$45.94
I	Full-Cost BEV Subscription ($/block) (E/G)	$119.76	$167.57	$156.74
J	Present BEV Subscription ($/block)	$12.41	$95.56	$85.98

PG&E is proposing changes to BEV rate design to account for a more accurate determination of marginal costs. We are proposing different methods for BEV-1 and BEV-2 because present rates for BEV-1 are far below 2023 marginal cost levels and there would be significant rate shock if BEV-1 customers were moved to the cost-based BEV subscription level. All schedules will still collect their allocated revenue requirement, but the BEV-1 subscription will be designed to increase at a slower rate, with more revenues being collected in energy charges. On the other hand, BEV-2 will be designed in a more cost-based manner because its cost-based BEV subscription level is only about double the present value instead of over ten times, like it is for BEV-1. Additionally, PG&E's revenue allocation transition plan, described in Chapter 2, supports that BEV-2 will not likely see a doubling of its BEV subscription all at once.

For BEV-1, PG&E proposes that the BEV subscription rate be increased from present values at a rate equal to half of the overall distribution revenue requirement increase. For example, if the BEV distribution revenue requirement increases by 10 percent, then the BEV subscription value for BEV1 should increase by 5 percent.

For BEV-2, PG&E proposes that the marginal-only BEV subscription rate (Line H in Table 7-4 above) be multiplied by the ratio of revenue requirement divided by total marginal cost revenue. For example, if the revenue requirement is two times the total marginal cost revenue, then the BEV subscription rate will be set at two times the marginal-only BEV subscription. However, if this results in a BEV subscription rate that is higher than the full-cost BEV subscription (Line I in Table 7-4 above), then the BEV subscription will be capped at the full-cost level.

After the BEV subscription rates and revenues are determined, PG&E will allocate all remaining distribution revenue to the schedules' energy rates. PG&E proposes to set the TOU differences to be average of their current differences (19.2 cents between peak and off-peak) and the differences from the marginal costs (11.9 cents). This averaging is especially important for generation and is discussed in more detail in the next section. Once the TOU difference is determined, PG&E will use an equal cents per kWh adder to collect all distribution revenue not collected by subscription charges. Please see Exhibit (PG&E-4), Appendix C for the proposed distribution rates for all schedules.

2. Generation Rate Design

Unlike distribution, PG&E's present rate revenue for generation is above the cost of service for BEV customers. Therefore, bundled BEV customers will be experiencing generation rate decreases during the four-year transition plan, which will help offset any rate increases they receive from distribution.

During the initial creation of the generation rate in D.19-10-055, more costs were allocated to the peak period than the marginal costs would require.[17] This intentional inflation of the peak rate, 4 pm to 9 pm, was to help encourage load shifting for this growing sector. However, as noted in the annual reports mentioned in Section D.2 above, this high peak rate does

[17] D.19-10-055, p. 10.

not seem to discourage usage in the peak by a significant amount.[18] This is likely due to many BEV customers not passing through the TOU difference to the EV end-user, so EV charging usage during the peak is not discouraged. We propose to eventually stop the artificial inflation of the peak period and have the TOU differences reflect only the differences in marginal cost. Rates that reflect the marginal costs delivers the most economically efficient rates to our customers and minimizes creating revenue shortfalls that could raise rates for all customers.

To minimize rate shock due to shrinking the TOU differences, PG&E proposes to use TOU differences equal to the average of the current (inflated) differences and the differences indicated by marginal costs.

The current rate design has no generation component in the BEV subscription charge, only energy rates which apply to bundled customers. While PG&E maintains that having some generation fixed costs in the BEV subscription charge would be more in line with cost causation, PG&E is not proposing to start including any generation component in the BEV subscription at this time.

As with distribution, once the TOU differences are calculated, an equal-cents adder will be applied to collect the entire generation revenue requirement. Please see Exhibit (PG&E-4) Appendix C for the proposed generation rates for all schedules.

3. Total Rate Discussion and Comparison to Other California Utilities

Present and proposed rates for BEV are shown in Table 7-5 below. There are two sets of proposed rates: one has no revenue allocation impacts so that the rate design is revenue neutral and bill impacts are comparable, the other includes the revenue allocation impacts of fully completing PG&E’s proposed four-year transition plan described in Chapter 2.

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[18] AL 7232-E, Attachment 1, pp. 23-24.

TABLE 7-5
PRESENT AND PROPOSED BEV RATES

Line No.	Rate	Present Rate	Proposed Rate (No Revenue Allocation Impacts)	Proposed Rate (With 4 Years of Revenue Allocation Impacts)
1	BEV-1			
2	Subscription Charge ($/10 kW)	12.41	12.41	35.52
3	Peak	0.38238	0.34634	0.35176
4	Off-Peak	0.19037	0.20163	0.20705
5	Super Off-Peak	0.16371	0.17751	0.18293
6	BEV-2 (Secondary)			
7	Subscription Charge ($/50 kW)	95.56	50.34	167.57
8	Peak	0.39720	0.36089	0.36321
9	Off-Peak	0.18397	0.20737	0.20968
10	Super Off-Peak	0.16070	0.18497	0.18728
11	BEV-2 (Primary)			
12	Subscription Charge ($/50 kW)	85.98	40.73	156.74
13	Peak	0.38832	0.36193	0.35972
14	Off-Peak	0.17944	0.20689	0.20468
15	Super Off-Peak	0.15678	0.18420	0.18198

The rates with the revenue allocation impacts represent a bundled average rate increase of 8.0 percent split evenly over four years. While the proposed subscription charges are increasing by a large amount in percentage terms, they are still low in absolute value. The proposed BEV-1 and BEV-2 subscription levels after four years of increases represent the equivalent of about $3.55 and $3.35/kW demand charges respectively. The BEV-1 proposed value is much lower than the “full cost” value of $11.98/kW that cost-based ratemaking would calculate because of their high Marginal Customer costs. These are also substantially lower than other Commercial and Industrial (C&I) demand charges which are in the $20-30/kW range. Additionally, C&I schedules have a separate customer charge while the BEV rates have no customer charge.

Both San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (SCE) have Non Residential EV charging schedules. SDG&E’s schedule EV-HP also uses subscription blocks that are approximately $3/kW, but they add an additional customer charge of $213.30 for customers up to 500 kW and a $766.91 charge for customers above 500 kW.[19] In SCE's 2025 GRC II proposal, schedules TOU-EV-8 (20 kW to 500 kW) and TOU-EV9 (over 500 kW) include customer charges of $140 and $1,641, respectively.[20] Although they currently have no demand charges, SCE's is requesting to phase in demand charges that go up to about $10/kW over six years starting in 2030.[21]

Since PG&E's proposal has no customer charge, it is substantially lower than SDG&E's current rates in terms of fixed charges. While our "Year 4" proposal is higher than SCE's current fixed charges, their demand charges will surpass ours in a few years. So, although PG&E's subscription charges are proposed to double after 4 years, that higher charge is still lower than comparable rate schedules at the other large Investor-Owned Utilities in California.

4. Rate Changes Between GRCs

After the initial rate design change on implementation, PG&E proposes that future revenue requirement changes in distribution and generation follow the same methods as were used to design these proposed rates, namely:

- For distribution, the BEV-1 subscription will increase by half of the percentage change in revenue requirement, with all remaining revenue going to energy charges. For BEV-2, both subscription and energy charges will change on an equal percentage basis until the full-cost level for the BEV subscription is reached. In all cases, PG&E will preserve the TOU differences established by the proposed rates.
- For generation, change rates by equal cents/kWh.

The methods for updating other rate components besides distribution and generation are given in Chapter 2.

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19 SDG&E Schedule EV-HP, Electric Vehicle High Power Rate, available at: <https://tariffsprd.sdge.com/sdge/tariffs/?utilId=SDGE&bookId=ELEC&sectId=ELEC-SCHEDS&tarfRateGroup=Commercial/Industrial%20Rates>, (accessed Sept. 12, 2024)

20 A.24-03-019, SCE 2025 GRC II, Exhibit SCE-04, Appendix B, pp. 17 and 22.

21 A.24-03-019, SCE 2025 GRC II, Exhibit SCE-04, pp. 36-38.

F. Conclusion

PG&E's respectfully requests that the Commission adopt its proposed rate designs for BEV-1 and BEV-2 described in Section E, with illustrative proposed rates provided in Appendix C. In addition, PG&E requests that the Commission extends the BEV performance reporting required by D.19-10-055 by another 3 years.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 8

THE ECONOMIC DEVELOPMENT RATE

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THE ECONOMIC DEVELOPMENT RATE

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 8
THE ECONOMIC DEVELOPMENT RATE

A. Introduction

This chapter presents Pacific Gas and Electric Company's (PG&E) proposal for its Economic Development Rate (EDR) in the 2023 General Rate Case Phase II (GRC II). Public Utilities Code (Pub. Util. Code) Section 740.4(a) provides that the California Public Utilities Commission (CPUC or Commission) shall authorize public utilities to engage in programs to encourage economic development. PG&E proposes to continue offering its EDR to attract jobs and companies to locate in California when they have out-of-state choices and to retain companies considering leaving California. PG&E proposes to continue its EDR until December 31, 2027 (or until a decision is rendered in Phase II of PG&E's 2027 GRC, whichever is later), and to continue the CPUC-adopted structure of the current EDR Program offering, which allows participation by qualified large business customers up to 150 megawatts (MW), as well as by qualified small businesses of up to an additional 5 MW.

B. Summary of Proposals

In this 2023 GRC II proceeding, PG&E proposes to continue offering our existing three-tiered rate discount amounts, as adopted in PG&E's 2020 GRC II, and increase our total program cap to 200 MW. With the new GRC II schedule growing to a four-year rate cycle, the previously requested 150 MW cap may become exhausted in the 4-year GRC cycle period. In PG&E's previous rate cycle, PG&E enrolled 150 MW of load on the rate in three years (the old rate case cycle, now replaced with a 4-year cycle), targeting 50 MW per year. However, in 2021, the cap became exhausted prior to receiving a decision in the subsequent 2020 GRC II proceeding. In our current rate cycle, PG&E appears to be on pace to enroll all 150 MW of load before we receive a decision in this GRC II proceeding. For future 4-year rate case cycles a cap of 200 MW will avoid the potential of hitting the cap before the final decision in our 2027 GRC II and subsequent GRC II proceedings.

The current EDR Program's structure was defined in PG&E's 2020 and 2017 GRC II proceedings.[1] Specifically, in PG&E's 2017 GRC II, the CPUC approved an all-party EDR settlement that modified our previous EDR Program to become a three-tiered system based on unemployment level, with several new terms and conditions, as follows:

- For businesses with 150 kilowatts (kW) of demand or more, the CPUC increased the cap to 150 MW cap and allowed those MWs to be applied to any of the three rate reduction tiers (i.e., an unrestricted cap).
- For small businesses with less than 150 kW of demand, the CPUC added a separate, new 5 MW cap.
- For the entire program, the CPUC allowed any leftover unsubscribed load below the cap in the program to be rolled over and applied using the same tiered bucket rules adopted in Decision (D.) 18-08-013.

In PG&E's 2020 GRC II, the EDR structure was slightly modified to reduce the rate reduction for the highest tier from 25 percent to its current level of 20 Percent.[2] For continuity, PG&E is not proposing to change the currently adopted EDR structure of discounted rates. Due to changes to marginal costs, however, PG&E is proposing minor changes to the allocation factors of the rate reductions between generation and distribution, as shown below in Table 8-1.

TABLE 8-1
REVISED ALLOCATION FACTORS OF EDR RATE REDUCTIONS TO GENERATION AND DISTRIBUTION

Line No.	Rate Reduction Component	Transmission	Primary	Secondary
1	Generation Current	78%	35%	40%
2	Generation Proposed	73%	44%	35%
3	Distribution Current	22%	65%	60%
4	Distribution Proposed	27%	56%	65%

[1] See D.18-08-013, as modified by D.21-11-016.

[2] See D.21-11-016, pp. 128-131.

C. Organization of the Rest of This Chapter

The remainder of this chapter is organized as follows:

- Section D – Background on PG&E's Current EDR Program;
- Section E – 2022 Survey of EDR Applicants;
- Section F – Parameters of PG&E's Proposed EDR Program;
- Section G – Contributions to Margin and Rate Calculations;
- Section H – California's Economic Conditions; and,
- Section I – Conclusion.

D. Background on PG&E's Current EDR Program

Under Pub. Util. Code Section 740.4(a), the Commission is required to authorize the public utilities that it regulates to engage in programs to encourage economic development.[3]

On November 13, 2012, PG&E filed an *Application for Approval of Economic Development Rate for 2013-2017,* to extend and revise its then-existing EDR Program. In D.13-10-019, the CPUC authorized PG&E to offer an EDR tariff with a 200 MW cap, and a maximum rate reduction of 30 percent, to help California compete for out-of-state business. The EDR Program adopted for PG&E in 2013 offered qualified customers a discounted electric rate over a five-year period to support our state's business attraction efforts to encourage an influx of out-of-state businesses, as well as its business retention and expansion efforts with California businesses who would otherwise move their operations to another state.

In PG&E's 2017 GRC II, D.18-08-013, the CPUC approved an all-party EDR settlement that modified PG&E's EDR Program to a three-tiered system based on levels of unemployment, with several new terms and conditions as discussed in Section A (Summary), above.[4]

Finally, in PG&E's 2020 GRC II, the CPUC approved another all-party settlement to renew the EDR Program from 2018 to 2020, incorporating the following changes agreed to by the settling parties:

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[3] Pub. Util. Code740.4(a).

[4] See D.18-08-013, pp. 63-64.

- Three discounted tiers[5] of 12 percent (Standard Tier), 18 percent (Mid-Enhanced Tier), and 20 percent (Enhanced Tier).
- Updated allocation factors of EDR discounts to generation and distribution charges, as follows:

TABLE 8-2
GENERATION AND DISTRIBUTION ALLOCATION FACTORS
(ADOPTED IN D.21-11-016)

Line No.		Transmission	Primary	Secondary
1	Generation	78%	35%	40%
2	Distribution	22%	65%	60%

In response to Application 19-11-019, PG&E and settling parties eventually reached an all-party settlement with minor changes to the EDR Program from the prior GRC II. PG&E proposed to offer three discounted tiers of 12 percent (Standard Tier), 18 percent (Mid-Enhanced Tier) and 20 percent (Enhanced Tier). PG&E proposed to lower its Enhanced Tier, which was previously 25 percent, to 20 percent. PG&E and the settling parties filed the settlement agreement on April 8, 2021, settling all EDR-related matters at issue in PG&E's original filling. A highlight of this program was the work that the Joint CCA's and PG&E put into updating the allocation factors in the EDR discount coming from transmission for PG&E's distribution and generation rates. The two parties settled on the percentages described above with the hopes of allowing CCAs to participate in their own EDR Program more easily if they elected to do so.

1. PG&E's EDR Program's Support for Businesses of 150+ kW Demand

Through PG&E's active efforts to attract and retain qualified businesses in California, from 2014 to December 2023, the EDR Program has achieved the results illustrated below in Table 8-3. The jobs and wage numbers are listed in the annual compliance reports that have been reported to the CPUC.

[5] The EDR Program offers three rate reduction tiers that depend on the annual average of the city or county unemployment rate where the business is located. Greater discounts go towards businesses in cities and counties with higher unemployment rates.

TABLE 8-3
PG&E'S EDR PROGRAM – MW SIGNED PER YEAR (2014 – JULY 2024)

Line No.	Year	MW Enrolled in PG&E's EDR Program
1	2014	20.3
2	2015	19.1
3	2016	20.1
4	2017	43.7
5	2018	41.9
6	2019	24.2
7	2020	71.8
8	2021	11.6[(a)]
9	2022	50.2
10	2023	42.4
11	2024 Jan-July	43.5

(a) 2021 PG&E exhausted the program and only had 11.6 MW of load left to offer.

The EDR Program has been very successful in supporting Governor Newsom's Office of Business and Economic Development's goal of attracting and retaining jobs, as well as business investment, in areas with high unemployment. From 2014 through June 2024, 144 projects signed EDR contracts with PG&E, which, combined, have created or retained approximately 21,000 jobs. The EDR incentive has served as a critical part of the state of California's strategy to support the economic vitality of the Central Valley inland region. These areas rely on incentives such as the EDR to be able to compete with other, lower-cost states and countries. This program's ability to provide an appropriate rate reduction on electricity for at-risk businesses must be retained to ensure that the overall incentive packages, coordinated through the efforts of the Governor's Office of Business and Economic Development, remain successful and competitive. Therefore, in this proceeding, PG&E proposes to continue its currently-adopted EDR Program with the tiers previously approved in 2021, while increasing the cap from 150 to 200 MW due to the change in rate case cycle length.

Since 2014, the EDR Program has provided benefits such as:

- Over $184,000,000 of new annual recurring revenue to PG&E to help lower the bills of all customers, because this is incremental electric revenue that would have relocated out-of-state, closed operations, or not come to California.

- More than 20,000 new or retained jobs that otherwise would not exist in California.
- 87 Retention projects that would have closed operations, resulting in retaining over 11,000 jobs and keeping over 288 million kilowatt-hours (kWh) served in PG&E's territory.
- 33 Attraction projects that chose PG&E service area, rather than nearby states, resulting in over 5,700 jobs created and over 633 million kWh that is or will be served by PG&E.
- 14 Expansion projects that chose to expand in PG&E service area rather than nearby states, resulting in over 2,000 jobs created.

TABLE 8-4
EDR PROGRAM RESULTS

Line No.	Metric	2014-2017 EDR Program[(a)]	2018-2020 EDR Program[(a)]	2021-2024 EDR Program[(a)]
1	Projects Signed	43	46	49
2	Total Energy Load Per Tier	12%: 31 MW 18% 4 MW 30%: 64 MW Total: 99 MW	12%: 81.3 MW 18%: 5.9 MW 25%: 18.6 MW 30%: 16.7 Total: 122.5 MW	12%: 70.3 MW 18%: 53.6 MW 20%: 26.5 MW Total: 150.4 MW
3	Projected Jobs Created	9,684	6,633	8,676
4	Actual Jobs Created	9,047	5,466	6,432
5	Actual Wages Created	$76,899,978.30	$855,993,886	$1,029,911,864* *as reported by PG&E EDR Customers
6	Projects Signed by Region	Bay Area: 12 Central Coast: 2 Greater Sacramento: 0 North Sacramento Valley: 7 San Joaquin Valley: 22	Bay Area: 12 Central Coast: 3 Greater Sacramento: 1 North Sacramento Valley: 6 San Joaquin Valley: 24	Bay Area: 11 Central Coast: 3 Greater Sacramento: 1 North Sacramento Valley: 9 San Joaquin Valley: 25
7	Unused Cap (MW)	80.6 MW (rolled over)	123.18 MW (as of December 2019)	48 MW as of August, 2024

2. PG&E's EDR Program's Added Support for Small Businesses in Recent Years

With the CPUC's adoption of a separate 5 MW EDR cap for small businesses in D.18-08-013, PG&E has been able to use the EDR to also support struggling small businesses in our service area. In the past two rate case cycles, we have not reached the 5 MW cap and do not anticipate a need to increase this figure for the now longer four=year rate case cycle. As a recent example, due to rising costs after the COVID pandemic, a small bakery production and distribution center in Berkeley, California, with 20 kW of electric load and 22 employees, was considering closing operations. The discounted electricity rate they now receive under PG&E's EDR Program helped make it possible for this small bakery production center to stay in business.

E. 2022 Survey of EDR Applicants

In PG&E's 2020 GRC II, the CPUC adopted an all-party settlement agreement requiring PG&E to conduct research among eligible businesses on their experiences with enrollment and participation in PG&E's EDR Program. Specifically, the settlement agreement required PG&E to conduct a survey of EDR applicants, with the goal of identifying areas for program improvement and refinement.

In February and March of 2022, PG&E conducted an online-based survey in compliance with the settlement agreement. In total, PG&E sent 106 survey invitations to customers. Of the 106 surveys, 94 surveys were sent to EDR customers, as well as 22 surveys being sent to non-EDR customers who had engaged with the PG&E EDR team about the rate—either by applying or working directly with a PG&E employee, but who did not sign an EDR contract. During the survey period, PG&E sent three reminders to each customer requesting that they complete the survey. The survey was ultimately completed by 12 customers (8 EDR customers and 4 Non-EDR customers).

The goal of the survey was for PG&E to assess the overall experience of businesses during the application and enrollment process to better understand where PG&E is performing well, as well as identify areas for improvement.

Overall, all eight of the twelve respondents who are currently enrolled on the EDR were "Very Satisfied" with the EDR. Of the four respondents that ended up not signing an EDR contract, one customer was approved for the EDR but ultimately decided not to enroll due to high commercial, wage and labor costs and ultimately did not locate in California. The top considerations from the four customers who are not utilizing the EDR as to important factors in choosing California were availability of skilled labor, tax credits and the size of the EDR discount.

F. Parameters of PG&E's Proposed EDR Program

This section outlines the parameters and qualification process of PG&E's existing EDR Program whose rate reduction structure we propose continue "as-is" in this GRC II proceeding, while increasing the current 150 MW cap to 200 MW.

For this rate cycle, PG&E is proposing to increase the overall cap from 150 MW to 200 MW. In the past, the GRC rate case cycles had been assumed to be roughly three years in length, with a 150 MW cap where 50 MWs were targeted to enroll each year. In the current cycle, we expect that PG&E will most likely have awarded to customers all the space in our existing 150 MW cap prior to receiving a decision in this GRC. In the previous GRC II rate cycle PG&E ran out of cap space in 2021, the last year of the cycle.

To qualify for PG&E's EDR discount, an interested business must:

1) Be a relocatable type of business (e.g., a retail store would not be a relocatable business because it is locally tied to its consumer base);
2) Pass an eligibility review with the California Governor's Office of Business and Economic Development (GoBiz);
3) Supply documentation establishing that, as an in-state business, they have:
    a) Out-of-state options for either a new facility or an expansion facility, or
    b) A current operation in California that is at risk of ceasing operations;
4) Sign an affidavit attesting to the fact that, but for the EDR rate incentive, either on its own or in combination with a package of other offerings, the customer would not have retained or expanded its load within California or would not have located in California; and
5) Once in the EDR Program, each participating business must submit an annual report including the number of jobs, types of jobs, and average wages and benefits for the jobs created or retained.

1. Rate Reduction Tiers

PG&E proposes to retain the current EDR Program's three rate reduction tiers, which depend on the annual average of local unemployment rate at the city or county level, in comparison to the annual average unemployment across California. PG&E's current EDR rate reduction tiers, which set the monthly bill discount level for which a business is eligible, are:

- Tier 1 (Standard) – 12 percent/month;

- Tier 2 (Mid-Enhanced) – 18 percent/month; and
- Tier 3 (Enhanced) – 20 percent/month.

The tiers that provide a greater rate reduction for which the applicant may be eligible are for qualified businesses located in cities and counties with higher unemployment rates. Specifically, PG&E's Tier 2 (mid-enhanced level) provides an 18 percent rate reduction for businesses in those cities and counties that have an annual unemployment rate between 130 and 150 percent of California's average. Tier 3, the 20 percent rate reduction, is only available in those cities and counties that have an annual unemployment rate above 150 percent of California's average. For all other areas of PG&E's service territory, qualifying customers are eligible for the standard 12 percent rate reduction under Tier 1. PG&E is proposing to retain these three rate reduction tiers and the current associated unemployment thresholds.

G. Contribution to Margin and Rate Calculations

The EDR allows PG&E to attract and retain customers, resulting in revenue from businesses that otherwise would not have located or remained in California. This results in sales that are higher than they would have otherwise been, absent these customers. When PG&E can retain or attract sales at a rate that is lower than the tariffed rate, but higher than the marginal cost of service, it helps to maintain or add to Contribution to Margin (CTM). This CTM can be used to keep rates to non-participating customers lower than they otherwise would be by allowing PG&E to spread its costs over more units of sales, thus benefiting all ratepayers. And, once the five-year rate reduction contract period is over, all customers also enjoy greater benefits when customers who attracted to or retained in California by the EDR begin to pay bills without any further rate reduction.

Since the start of our current EDR Program, the EDR has been supported by an evaluation of current marginal cost and rates. PG&E's analysis of the program on a forward-looking basis utilizes schedule-average rates and marginal costs proposed in this proceeding.

PG&E calculated the maximum rate reduction that could be applied to each rate schedule, on a schedule average basis, for bundled customers using a conservative set of assumptions, meaning assumptions that would tend to reduce the level of the maximum potential rate reduction. Specifically, PG&E calculated the maximum available rate reduction by subtracting the following components from the bundled bill: transmission charges, generation marginal energy costs, constrained distribution capacity costs, marginal customer costs, and Non-Bypassable Charges.[6]

As shown below in Table 8-5, the maximum achievable rate reduction in distribution-constrained areas was greater than the proposed 20 percent maximum rate reduction for all customer classes. Notably, while the CTM is generally positive when the 20 percent rate reduction is applied, the CTM would be much greater for customers located in distribution areas that are not subject to distribution capacity constraints (yielding a lower marginal cost) or in cases where the lower 12 or 18 percent rate reduction are applied. To illustrate the potential CTM in distribution areas that are unconstrained, PG&E has also shown the maximum potential rate reduction in unconstrained areas in Table 8-5. Thus, PG&E believes it is reasonable to propose to retain its three adopted rate reduction tiers of 12 percent, 18 percent, and 20 percent.

TABLE 8-5
MAXIMUM POTENTIAL EDR RATE REDUCTION

Line No.	Customer Class	Maximum Potential Rate Reduction (Distribution Constrained Areas)	Maximum Potential Rate Reduction (Distribution Unconstrained Areas)
1	SLP	46.1%	52.6%
2	A-10/B-10S	46.3%	53.0%
3	E-19P/B-19P	39.7%	46.5%
4	E-19S/B-19S	48.7%	54.9%
5	E-20T/B-20T	30.9%	30.9%
6	E-20P/B-20P	39.6%	47.0%
7	E-20S/B-20S	45.3%	51.6%

One enhancement to the EDR Program, required by D.13-10-019, was to provide for specific treatment of rate reductions for Direct Access and Community Choice Aggregation (DA/CCA) customers.[7] As implemented, rate

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6 These include: Public Purpose Program, Nuclear Decommissioning, Wildfire Fixed Charge, Wildfire Hardening Charge, Recovery Bond, Recovery Bond Credit, Competition Transition Charge, New System Generation Charge, and Power Charge Indifference Adjustment Charge rate components.

7 See D.13-10-019, pp. A-1 to A-2.

reductions were applied separately to bundled customers and DA/CCA customers by allocating the rate reduction to distribution and generation charges. The current EDR schedule provides the proportions that will be used to allocate the rate reductions to the generation and distribution portions of the bills. PG&E continues to believe this approach to deriving the rate reductions to participating customers is appropriate. However, the proportions adopted in 2020 do not align with the CTM analysis provided herein. In particular, the contribution of generation to the total CTM calculation for transmission and secondary service voltage levels have decreased compared to the original values, whereas the contribution of generation to the total CTM calculation for primary service voltage levels has increased. Accordingly, PG&E proposes to revise these allocation factors in this proceeding. The revised allocation factors are shown in Table 8-6, together with the current values.

TABLE 8-6
REVISED ALLOCATION FACTORS OF EDR RATE REDUCTIONS TO GENERATION AND DISTRIBUTION

Line No.	Rate Reduction Component	Transmission	Primary	Secondary
1	Generation Current	78%	35%	40%
2	Generation Proposed	73%	44%	35%
3	Distribution Current	22%	65%	60%
4	Distribution Proposed	27%	56%	65%

H. California’s Economic Conditions

Since its lowest point of our State’s economy in 2020 during the onset of the COVID pandemic, the California economy has improved. However, it is concerning that, as of July 2024, statewide unemployment figures have risen higher than those of the latter portions of 2019.

In July 2023, California’s statewide unemployment rate was 4.8 percent. However, as of May 2024, this figure had increased to 5.3 percent. For refence, the United States (U.S.) nationwide unemployment rate as of May 2024 was a full 1 percent lower than California’s.

Within PG&E’s service territory, the Counties of Merced, Tulare and Colusa still had high unemployment rates (11.5 percent, 12 percent, and 19.2 percent) as of June 2024, nearly double the average for our state as a whole.[8] In addition, Kings and Fresno counties both had unemployment rates exceeding 8 percent as of June 2024.

As of August 2024, California's unemployment rates align closely with those from right before conditions during the Covid-19 crisis. As illustrated further below in Table 8-7, California's inland areas have not had the same job growth or investment activity as compared with the state's coastal areas. As a result, there have recently been multiple initiatives across California that have focused on lifting inland regions to match the prosperity seen in other parts of our state. Recently, California's Governor's Office of Business and Economic Development has implemented an initiative called "Regions Rising Together,"[9] to build a comprehensive plan seeking to bring more of California's fast-growing prosperity into inland regions through investment, policy, and sustainable development. Other inland initiatives have also been launched, such as "Inland California Rising,"[10] a broad coalition of leaders and organizations in the business, philanthropic, non-profit, and public sectors which have formed to improve progress for the inland counties.

PG&E's EDR Program aligns very well with these recent initiatives, since the EDR is structured to provide a higher rate reduction only to those counties with higher unemployment rates, which are largely located in inland areas. Of the 47 counties in California, 21 (See Table 8-7) are eligible for either the Mid-Enhanced (18 percent) or Enhanced (20 percent) rate reduction, meaning their unemployment rate in June of 2024 was over 125 percent of the state average. California-wide, PG&E's service area includes almost all the counties with unemployment rates higher than the statewide average, which was 5.3 percent as of April 2024. (See Table 8-7, below).

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8 Employment Development Dept. (EDD), Unemployment Rate and Labor Forced, available at: <https://labormarketinfo.edd.ca.gov/data/unemployment-and-labor-force.html> (accessed Sept. 12, 2024).

9 California Governor's Office of Business and Economic Development, Regions Rise Together, available at: <https://business.ca.gov/regions-rise-together-governors-office-of-business-and-economic-development-shares-new-initiative/> (accessed Sept. 12, 2024).

10 *Id.*

TABLE 8-7
2024 PG&E SERVICE AREA UNEMPLOYMENT RATES AND TIER DISCOUNT BY COUNTY UNEMPLOYMENT RATE % TIER UTILITY

Line No.	County	Unemployment Rate	EDR Discount
1	Alameda	4.6%	12%
2	Alpine	5.9%	12%
3	Amador	5.6%	12%
4	Butte	6.4%	12%
5	Calaveras	5.1%	12%
6	Colusa	19.2%	20%
7	Contra Costa	4.7%	12%
8	El Dorado	4.7%	12%
9	Fresno	9.1%	20%
10	Glenn	7.6%	18%
11	Humboldt	5.4%	12%
12	Kern	10.1%	20%
13	Kings	10%	20%
14	Lake	6.6%	12%
15	Lassen	7.1%	18%
16	Madera	8.9%	20%
17	Marin	3.7%	12%
18	Mariposa	6.4%	12%
19	Mendocino	5.7%	12%
20	Merced	11.5%	20%
21	Monterey	10.5%	20%
22	Napa	4.2%	12%
23	Nevada	4.5%	12%
24	Placer	4.3%	12%
25	Plumas	11.6%	20%
26	Sacramento	4.9%	12%
27	San Benito	7.5%	18%
28	San Francisco	3.7%	12%
29	San Joaquin	7.1%	18%
30	San Luis Obispo	4.0%	12%
31	San Mateo	3.5%	12%
32	Santa Barbara	5.1%	12%
33	Santa Clara	4.1%	12%
34	Santa Cruz	7.4%	18%
35	Shasta	6.3%	12%
36	Sierra	7.5%	18%
37	Siskiyou	8.3%	20%
38	Solano	5.3%	12%
39	Sonoma	4.2%	12%
40	Stanislaus	7.4%	18%
41	Sutter	9.8%	20%
42	Tehama	6.9%	18%
43	Trinity	7.1%	18%
44	Tulare	12%	20%
45	Tuolumne	5.7%	12%
46	Yolo	5.8%	12%
47	Yuba	8.1%	20%

1. Status of Competition Among National Utilities

Many larger utilities in the U.S. have robust economic development programs, not only because these programs strengthen the communities they serve, but also because they either have a high return-on-investment (where a utility's profits depend on load), or CTM, helping cover rates for all customers (in states like California cost-of-service decoupled ratemaking). Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) employ economic development teams, with 5 to 7 employees, who market and administer a variety of incentives, rebates, and other programs. Both SDG&E and SCE offer similar rate reduction programs to PG&E's EDR. By comparison, PG&E's Economic Development Program has achieved our EDR results with a current staff of only two employees.

2. EDR Successes: Customers Choosing PG&E Service Territory

In 2021, a home prefabricated design and construction facility EDR application was submitted and approved. This new facility, built in Kern County, has created over 400 new jobs. The EDR was a critical factor in the customer's decision of whether to build the facility in California instead of in Nevada.

In 2024, a steel door manufacturer submitted an EDR application which was approved. The company then had locations on the East Coast and Mid-West. The EDR discount was a key incentive for the company to build their first facility on the West Coast, in West Sacramento.

While continuing PG&E's current EDR Program's current rate reduction structure will not match other states on a cost basis, it will still help the Governor's Office of Economic Development ensure that California is not prematurely eliminated as businesses perform their site selection processes. It remains clear that PG&E's EDR continues to be an important part of a comprehensive package of incentives and initiatives that encourages investment in California, with an emphasis on high unemployment areas that need economic development the most, such as many of our inland cities and counties.

The current EDR Program, which resulted from an all-party settlement in PG&E's 2020 GRC II, was carefully designed to work both during economic recession cycles and in expansionary cycles—either of which can take place during the four-year GRC rate case cycle. In 2020, during the height of the pandemic, PG&E had 11 retention projects, totaling over 22 million kWh saved and over 1,900 jobs retained.

To illustrate the effectiveness of the EDR Program, consider a plastic injection mold manufacturing facility that did not receive any new orders from March 2020 to September 2020. Sales were down 33 percent year to date over the same period for 2019. The customer stated that the PG&E EDR would help his chance of staying in business.

During recessions, the EDR is especially helpful for retaining companies in California that are seeking to move to lower-cost areas of the U.S. On the other hand, during times of economic expansion, the EDR is still important to help level the playing field with neighboring states by attracting new facilities or retentions/expansions at sites in California that the customer might do elsewhere. As economic activity increases across the U.S., California must continue to find ways to be more competitive to attract the growth that will be needed when an economic recession inevitably occurs, especially in inland areas of the state.

I. Conclusion

Since 2014, the EDR Program has helped create or retain over 20,000 jobs for California and added over $184,000,000 million of incremental, annual revenue to lower the cost of the grid to all ratepayers. The program's rate reductions are also self-funding due to its positive CTM. To date, PG&E's EDR Program has resulted in approximately $2 billion of combined wages and salary contribution (as reported to PG&E by customers on the program) to support California's economy. Because the past results discussed above have proven PG&E's existing EDR Program to have been beneficial to all stakeholders within California, PG&E respectfully requests that the Commission adopt PG&E's proposal that our current EDR Program be continued for this 2023 GRC II rate case cycle.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 9

RATE PROGRAMS FEES FOR SERVICES TO COMMUNITY CHOICE AGGREGATION AND DIRECT ACCESS ELECTRIC SERVICE PROVIDERS

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CHAPTER 9
RATE PROGRAMS FEES FOR SERVICES TO COMMUNITY CHOICE AGGREGATION AND DIRECT ACCESS ELECTRIC SERVICE PROVIDERS

A. Introduction

In this chapter, Pacific Gas and Electric Company (PG&E) sets forth its proposals for changes to fees and respective Rate Schedules in the 2023 General Rate Case Phase II (GRC II) for services rendered to non-utility Energy Service Providers (ESP) under two alternative energy provider programs, Direct Access (DA) and the Community Choice Aggregation (CCA).

B. Summary of Proposals

Specifically, this chapter proposes fee escalations for three services provided to ESPs under the DA and the CCA programs, as shown below in Table 9-1.

In addition, PG&E proposes that the California Public Utilities Commission (CPUC or Commission) allow PG&E to propose future escalations to the service fees presented in this chapter by using the Commission's Tier 2 Advice Letter process instead of a future rate design proceeding. PG&E proposes moving forward with the Tier 2 Advice Letter process following a final decision in this proceeding, as opposed to waiting a minimum of four years until PG&E's next GRC II rate cycle, to keep PG&E's service fees more current and sustainable moving forward.

TABLE 9-1
SUMMARY OF PROPOSED CHANGES

Line No.	Name of Service/Proposal	As Adopted by CPUC Decision (D.) 21-11-016	As Proposed in This Chapter	Discussed in Section
1	Meter Data Management Fee	$0.14	$0.17	E
2	Rate-Ready Consolidated Billing Fee	$0.21	$0.25	E
3	Bill-Ready Consolidated Billing Fee	$0.21	$0.25	E
4	Method for Proposing Future Fee Escalations	N/A	Tier 2 Advice Letter	E

C. Organization of the Rest of This Chapter

The remainder of this chapter is organized as follows:

- Section D – Background;
- Section E – Proposed Fees and Rate Schedule Changes;
- Section F – Justification and Methodology;
- Section G – Conclusion;
- Attachment A – Proposed Red-lined Fee Revisions to Schedule E-CCA; and
- Attachment B – Proposed Red-lined Fee Revisions to Schedule E-ESP.

D. Background

The service fees discussed in this chapter are for specific services PG&E offers to ESPs in PG&E's service territory. ESPs are independent, non-utility entities that provide alternative electric supply to retail customers under the DA and CCA service programs.

The DA Service Program allows customers within PG&E's service territory to, at the customer's election, purchase electric power and additional energy services from third-party ESPs.[1] The CCA service program allows cities and counties to provide electric services for residents and businesses located within their service area.[2]

PG&E offers specialized metering and billing services to ESPs who participate in PG&E's CCA and DA programs. Accordingly, PG&E incurs "incremental costs"[3] for providing these services to ESPs.

Services offered to ESPs include the following: (1) Meter Data Management Agent, (2) Rate-Ready Consolidated Billing (Rate-Ready Billing), and (3) Bill-Ready Billing services. The Master Data Management Agent service provides meter data to ESPs through PG&E's Data Exchange Server, for a fee charged per meter per month.[4] The Rate-Ready and Bill-Ready Billing service

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[1] Terms and services applicable to the DA Program are governed by PG&E's Electric Rule 22 tariff.

[2] See California Public Utilities Code Section 366.2. Terms and service applicable to the CCA Program are governed by PG&E's Electric Rule 23 tariff.

[3] Electric Rule 22, Sheet 7, Section B.14, Service Fees and Other Charges; Electric Rule 23, Sheet 7, Section B.14, Service Fees and Other Charges.

[4] Electric Rate Schedule E-ESP, Sheet 1, Section 5a; Electric Rate Schedule E-CCA, Sheet 4, Section 6a.

fees are charged per meter, per billing cycle, and covers PG&E's cost of presenting and processing energy charges and customer payments on behalf of ESPs.[5]

Historically, updates to these service fees have been infrequent and limited. However, in PG&E's 2017 GRC II proceeding, the Commission adopted an uncontested settlement agreement which, among other things, significantly decreased PG&E's fees for providing Meter Data Management Agent, Rate-Ready Billing, and Bill-Ready Billing services to ESPs to reflect PG&E's process efficiencies and automation.[6]

Since 2018, the Master Data Management Agent, Rate-ready Billing, and Bill-ready service fees have been in place and unchanged. In 2018, the Commission adopted a settlement agreement allowing PG&E to adopt PG&E's current fees beginning in the second fiscal quarter of 2018.[7] While the Commission required the revised service fees to remain the same until PG&E's 2020 GRC II proceeding,[8] PG&E did not propose any updates to the service fees in its 2020 GRC II proceeding. Thus, PG&E's service fees have not reflected any changes to PG&E's costs, such as inflation rate impacts, in over five years.

In this 2023 GRC II proceeding, PG&E is proposing to update the Master Data Management Agent, Rate-ready Billing, and Bill-ready Billing fees to make these services current and consistent with PG&E's costs. PG&E proposes that these updated fees take effect upon the Commission's approval, without retroactive application. In addition, following a final decision in this proceeding, PG&E also proposes to allow for escalation of these fees using the Commission's Tier 2 Advice Letter process going forward.

E. Proposed Fees and Rate Schedule Changes

Specific fee revision proposals are presented below by applicable rate schedule by program as follows:

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5 Electric Rate Schedule E-ESP Sheet 2 Section 6A and Sheet 4 Section 6B; Electric Rate Schedule E-CCA Sheet 6 Sections 7a and 8a.

6 D.18-01-013, p. 15.

7 D.18-01-013, p. 15.

8 D.18-01-013, p. 9.

Community Choice Aggregation Program

- Table 9-2: Electric Schedule E-CCA

Direct Access Electric Service Provider Program

- Table 9-3: Electric Schedule E-ESP

TABLE 9-2
COMMUNITY CHOICE AGGREGATION PROGRAM
ELECTRIC SCHEDULE E-CCA

Line No.	Service Description	Tariff Reference	Fee Type	Current Fee[a]	Proposed Fee
1	Composite Master Data Management Agent Fee	Sheet 4: 6a	Per Meter Per Month	$0.14	$0.17
2	Composite Rate-Ready Billing Fee	Sheet 6: 8a	Per Account Per Billing Cycle	$0.21	$0.25
3	Composite Bill-Ready Billing Fee	Sheet 6: 7a	Per Account Per Billing Cycle	$0.21	$0.25

(a) Previously approved by D.18-01-013, p. 12.

TABLE 9-3
DIRECT ACCESS ENERGY SERVICE PROVIDER PROGRAM
ELECTRIC SCHEDULE E-ESP

Line No.	Service Description	Tariff Reference	Fee Type	Current Fee[a]	Proposed Fee
1	Composite Master Data Management Agent Fee	Sheet 1: 6a	Per Meter Per Month	$0.14	$0.17
2	Composite Rate-Ready Billing Fee	Sheet 2: 6A	Per Account Per Billing Cycle	$0.21	$0.25
3	Composite Bill-Ready Billing Fee	Sheet 4: 6B	Per Account Per Billing Cycle	$0.21	$0.25

(a) Previously approved by D.18-01-013 January 11, 2018, p. 12.

F. Justification and Methodology

The calculation illustrated below in Table 9-4 (“Escalation of Fees”) provides the annual rate increases for years 2021 through 2025, which are used to derive PG&E’s proposed fee from the current fee for each service. Applying escalation rates from 2021 through 2025 is appropriate and consistent with D.18-01-013 because, in that decision, the Commission approved PG&E’s current service fees through 2020. The escalation rates applied to PG&E’s proposed fee are consistent with the labor escalation rates within the "Average Labor Escalation – All Employees" category for each year presented, filed as part of Exhibit (PG&E-8) Human Resources in PG&E's 2023 GRC Phase I proceeding.

TABLE 9-4
ESCALATION OF FEES

Line No.	Name of Service	Current Fee	Escalation Rates[b] 2021	2022	2023	2024	2025	Proposed Fee[c]
1	Master Data Management Agent Fee	$0.14	3.03%	3.46%	3.46%	3.46%	3.46%	$0.17
2	Rate-Ready Billing	$0.21	3.03%	3.46%	3.46%	3.46%	3.46%	$0.25
3	Bill-Ready Billing	$0.21	3.03%	3.46%	3.46%	3.46%	3.46%	$0.25

(b) 2023 GRC, Exhibit (PG&E-8), Chapter 4, Section G, p. 4-22, Table 4-2 "2021-2026 Wage Increases," line 6 "Average Labor Escalation – All Employees."

(c) Proposed fees are based on escalation rates applied through 2025 with an anticipated approval date for implementation in 2026.

G. Conclusion

For all of the foregoing reasons, PG&E requests that the Commission adopt its proposed DA and CCA Service Fees for all applicable rate schedules and allow for future updates to these fees using the Tier 2 Advice Letter filing process.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 9

ATTACHMENT A

PROPOSED RED-LINED FEE REVISIONS TO

SCHEDULE E-CCA

PACIFIC GAS AND ELECTRIC COMPANY CHAPTER 9 ATTACHMENT A PROPOSED RED-LINED FEE REVISIONS TO SCHEDULE E-CCA

Pacific Gas and Electric Company®
U 39 San Francisco, California

	Revised	Cal. P.U.C. Sheet No.	41757-E
Cancelling	Revised	Cal. P.U.C. Sheet No.	35800-E

ELECTRIC SCHEDULE E-CCA Sheet 4
SERVICES TO COMMUNITY CHOICE AGGREGATORS

RATES: (Cont'd.)

6. ....METER DATA MANAGEMENT AGENT (MDMA) SERVICES

a. ....METER DATA POSTING

This service provides meter data to the CCA. Meter data will be made available to the CCA in EDI 867 format, and will be posted for retrieval by the CCA on PG&E's Data Exchange Server (DES).

Composite MDMA fee per meter per month .... ~~$0.14~~ $0.17 (N)

b. .... UNSCHEDULED METER READ

This fee will apply when a CCA requests cumulative reads or interval usage data for an account for a period outside the normal PG&E meter reading schedule. PG&E will attempt to accommodate requests for unscheduled reads. In no case will PG&E provide cumulative reads and/or interval usage data for a period greater than 33 contiguous days.

Per unscheduled meter read per cumulative meter........... no charge

Per unscheduled meter read per interval meter................. no charge

(Continued)

Advice	5225-E	*Issued by*	*Date Filed*	February 9, 2018
Decision	18-01-013	***Robert S. Kenney***	*Effective*	March 1, 2018
		Vice President, Regulatory Affairs	*Resolution*	

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 9

ATTACHMENT B

PROPOSED RED-LINED FEE REVISIONS TO

SCHEDULE E-ESP

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 9
ATTACHMENT B
PROPOSED RED-LINED FEE REVISIONS TO SCHEDULE E-ESP

ELECTRIC SCHEDULE E-ESP Sheet 1
SERVICES TO ELECTRIC SERVICE PROVIDERS

APPLICABILITY: This schedule applies to Electric Service Providers (ESPs) who provide direct access service to Customers, as defined in electric Rule 1 and Rule 22.

TERRITORY: The entire PG&E service territory.

RATES:

1. METER INSTALLATION

   If an ESP requests that PG&E install a meter for its Direct Access Customer, the rates will be as set forth in Schedule E-EUS.

2. METER TESTING

   If an ESP requests that PG&E test a meter for its Direct Access Customer, the rates will be as set forth in Schedule E-EUS.

3. METER REMOVAL

   If an ESP requests that PG&E remove the existing PG&E meter, as set forth in Rule 22, the charge shall be as set forth in Schedule E-EUS.

4. INSPECTION OF ESP-INSTALLED METERING EQUIPMENT

   If PG&E inspects ESP-installed metering equipment pursuant to Rule 22 and the ESP Service Agreement, the charge shall be as set forth in Schedule E-EUS.

5. METER DATA MANAGEMENT AGENT (MDMA) SERVICES

   a. MDMA services include meter reading setup, if required, to ensure the ESP's meter communication system is compatible with PG&E's meter reading system, data validation, editing and estimating to settlement quality form, data reads and data transfer to the MDMA Server.

      If PG&E performs MDMA services for an ESP the charge shall be:

      MDMA Composite Fee per meter per month.........................~~$0.14~~ (R) (T)

      $0.17

(Continued)

ELECTRIC SCHEDULE E-ESP Sheet 2
SERVICES TO ELECTRIC SERVICE PROVIDERS

RATES: (Cont'd.)

6. CONSOLIDATED PG&E BILLING

A. Rate-Ready Billing

If an ESP requests that PG&E calculate the charge and bill the ESP's Direct Access Customers for the energy supply portion of the Customer's bill, the prices shall be:

1) Composite Billing Fee, per service account per billing cycle……~~$0.21~~ $0.25 (R)

If PG&E is billing the ESP's Direct Access Customers for the energy supply portion of the Customer's bill, the ESP may request that PG&E provide the following additional billing-related services (Items 2 to 4) at no additional charge and is included in the Composite Billing Fee.

2) Duplicate Bill Request from ESP

3) Bill Adjustment

An ESP may request PG&E to adjust a Customer's bill for reasons unrelated to PG&E's calculation of the ESP's charges, such as the following:

a) ESP requested adjustment for reasons unrelated to the bill, such as a goodwill gesture or promotional discount.

b) Recourse adjustment as a result of dispute resolution.

c) Policy adjustment to satisfy a Customer's complaint.

(Continued)

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 10

IMPLEMENTATION AND

MARKETING, EDUCATION, AND OUTREACH

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IMPLEMENTATION AND
MARKETING, EDUCATION, AND OUTREACH

A. Introduction

In this chapter, Pacific Gas and Electric Company (PG&E) addresses two aspects of implementation for this 2023 General Rate Case Phase II (GRC II) application. First, in Section C of this chapter, PG&E describes our multi-year billing modernization initiative and its impacts on rate implementation timing. Second, in Section D of this chapter we discuss the Marketing, Education, and Outreach (ME&O) efforts that are necessary to support the proposals in this application.

B. Organization of the Rest of This Chapter and Witness Responsibilities

The remainder of this chapter is organized as follows:

- Section C – Billing Modernization Initiative and Constraints on Billing System Structural Changes;
- Section D – Marketing, Education, and Outreach; and
- Section E – Conclusion.

The witness responsibilities for this chapter are as follows:

- Emily Bartman – Section C (Billing Modernization Initiative and Constraints on Billing System Structural Changes); and
- Jamie Chesler – Section D (Marketing, Education, and Outreach).

C. Billing Modernization Initiative and Constraints on Billing System Structural Changes [Witness: Emily Bartman]

1. Introduction

PG&E is currently undertaking a multi-year billing modernization initiative which began in 2020 and is expected to be completed in Q4 of 2029. PG&E must modernize its outdated billing systems to continue to deliver reliable customer service, including continuing to provide billing services to customers. This modernization initiative will also allow more efficient implementation of future structural changes to the new billing system, including new rates and rate programs and modifications to existing rates and rate transitions (discussed further below). There are limits on PG&E's ability to implement the large number of already adopted projects in PG&E's rates implementation pipeline and any additional new rate proposals adopted in this proceeding that would require structural changes to the billing system during billing modernization. Thus, if the California Public Utilities Commission's (CPUC or Commission) final decision in this 2023 GRC II proceeding is approved prior to completion of billing modernization, these limitations will have an impact on when any rate design changes with structural[1] billing system impacts can be completed and rolled out into customers' bills.[2]

PG&E initially sought approval for a billing system upgrade project in its 2023 General Rate Case I (the 2023 GRC) (Application 21-06-021) to modernize its billing systems. However, in Decision (D.) 23-11-069, the CPUC found that PG&E's 2023 GRC Phase I application lacked sufficient detail to support the forecasted cost of its billing system upgrade project and authorized PG&E to file a separate application that includes seven categories of additional information.[3] PG&E submitted such an application in October 2024 (A.24-10-014).[4]

The following sections provide more details on the Billing Modernization Initiative and the status of PG&E's rates implementation pipeline.

---

1 A structural change would require coding and testing of new billing parameters and/or calculations, whereas a value change would entail a numerical adjustment to a parameter that already exists in PG&E's billing systems. Structural changes to the billing system require new variables, formulas, or billing determinants to calculate bills, which involve extensive coding and testing. Examples of structural changes would be adding a new charge or changing the hours associated with Time of Use Periods. Value changes entail a numerical adjustment to a rate parameter that is already coded in PG&E's billing systems, such as changing prices associated with an existing rate structure. Value changes do not require extensive coding changes and can be implemented much more quickly.

2 The current expectation for a GRC II decision in this proceeding is estimated to be no earlier than mid-2026, whereas the billing modernization is projected to be completed in Q4 2029.

3 D.23-11-069, pp. 546-550.

4 A.24-10-014, Billing Modernization Initiative, October 23, 2024.

2. Background on Multi-Year Billing Modernization Initiative

PG&E currently has two "legacy" billing systems, the Advanced Billing System (ABS) which includes over 140,000 customers who take service on our most complex electric rates[5] and the Customer Care and Billing system (CC&B) which includes about 6 million customers on simpler electric rates. These legacy systems were implemented before Advanced Metering Infrastructure was deployed and have required heavy customization to be able to support increasing numbers and complexity of rates and rate program combinations.

Recently-adopted rate projects that would typically be built in ABS (e.g., Net Billing Tariff (NBT)-Aggregation, NBT-Virtual, Residential Fixed Charge for Complex Net Energy Metering (NEM) customers in ABS) have been delayed until a replacement for ABS is in place, because there is too high a risk that building anything new in ABS might jeopardize billing for the over 140,000 customers on complex rates. Currently, ABS has exceeded its planned capacity of customers, which has resulted in latency in processing and performance issues that impact both PG&E's complex billing operations and customers.

The Billing Modernization Initiative consists of three major workstreams:

1. <u>Replace ABS with Oracle's Billing Cloud System (BCS) for Electric Customers</u>: PG&E has prioritized replacement of ABS with BCS to address the risk of not being able to provide accurate and timely bills for the over 140,000 electricity customers billed in ABS.[6] PG&E began work on BCS in 2020 and had originally planned to launch it in late 2023. However, rebuilding all of the complex ABS NEM rates in BCS proved to be more difficult than anticipated, and PG&E is now planning to launch BCS in mid-2025.
2. <u>Upgrade CC&B</u>: The delay in delivery of BCS to mid-2025 caused the final workstream to complete modernization of the billing system to be pushed out from 2026 to 2029 at the earliest, necessitating

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5 Such as NEM rates that involve calculations based on usage data from multiple meters (e.g., NEM-Aggregation, NEM-Virtual).

6 PG&E plans to move the gas customers in ABS into BCS at a later time. Moving the electric customers first will significantly reduce the risk of ABS issues.

reliance on CC&B for at least an additional three years. PG&E determined the best path to ensure stability of CC&B through this period is to implement a technical upgrade of CC&B from version 2.4 (implemented in 2017) to CC&B 25.1.[7]

3. Implement Integrated Modernized Billing System: The final phase will implement a new modernized billing system that will consolidate all customers in BCS and all customers in CC&B into one unified modular system. PG&E expects to complete implementation of the new more advanced billing system in 2029.

If the new integrated modernized billing system goes live at the end of 2029 as expected, new prioritized rate projects can begin to be programmed in 2030. The specific timelines and project details of the billing modernization were presented in PG&E's Billing Modernization Application to be filed in October 2024 (A.24-10-014).

3. PG&E's Rates Implementation Pipeline

As the Commission is aware, there is currently a significant backlog of PG&E rate projects that have already been adopted by the CPUC but are not yet able to be programmed into PG&E's billing system (Figure 10-1).[8]

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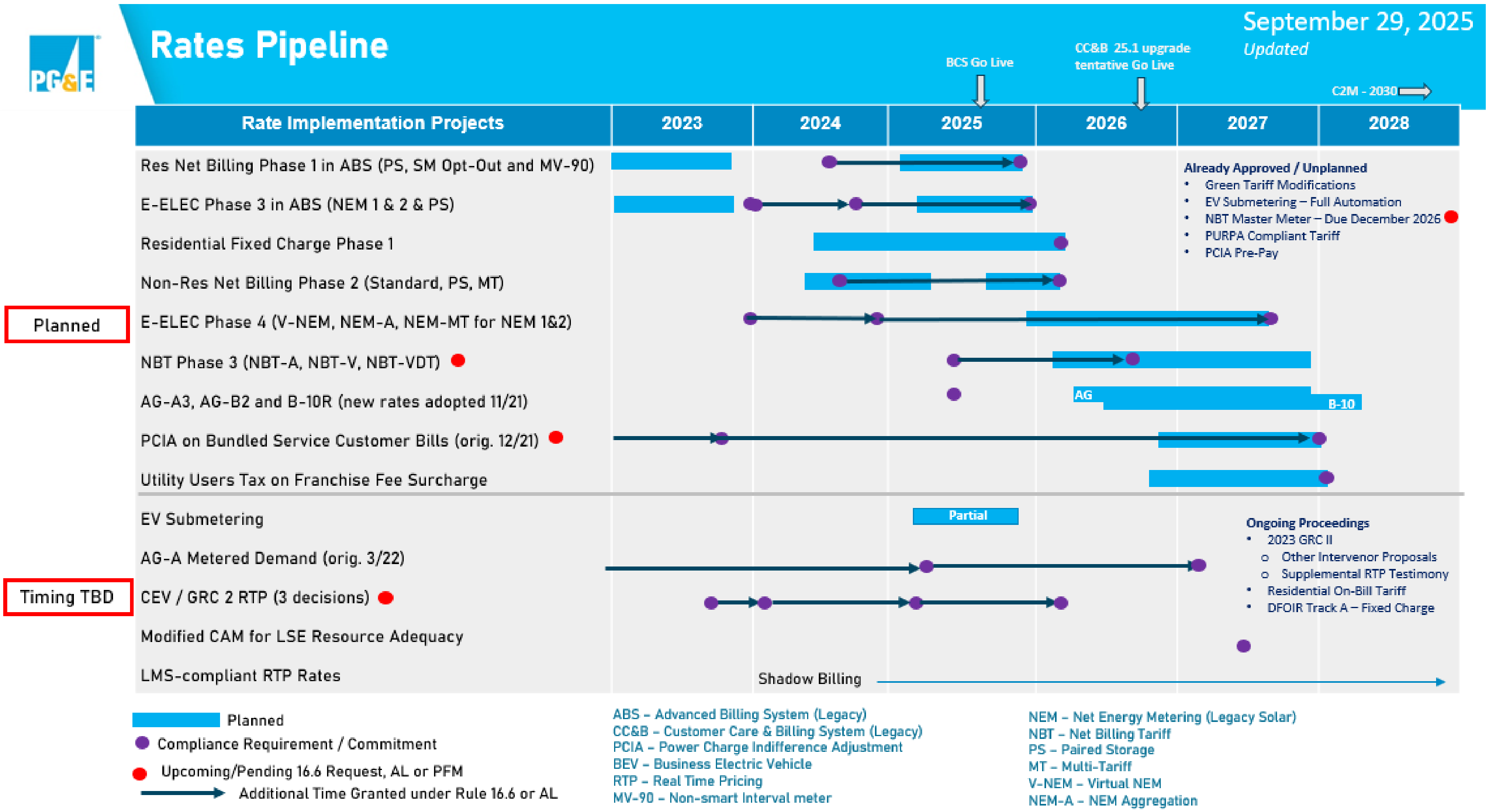
7 Please note that Oracle changed their versioning scheme after CC&B 2.9 was released, and 25.1 is the first release after 2.9.

8 PG&E meets regularly with the CPUC's Energy Division staff to keep them informed of the Billing Modernization Initiative and its impacts on already adopted rate projects.

FIGURE 10-1
PG&E'S RATES IMPLEMENTATION PIPELINE



Because of the planned go-live of BCS in mid-2025, rate projects that depend on BCS (for customers currently in ABS) can be programmed in parallel with the CC&B Upgrade and further modernized billing system development. In the last two years, PG&E has needed to submit requests for additional time to comply, under Rule 16.6, for over 20 rate projects adopted in previous GRC II and other proceedings. Table 10-1 below lists PG&E's requests for additional time to comply for rate projects, the status of those requests, and additional scheduling accommodation requests PG&E plans to submit over the next few years.

TABLE 10-1
PG&E'S REQUEST FOR ADDITIONAL TIME TO COMPLY UNDER RULE 16.6
(AS OF MARCH 20, 2025)

Previous Rule 16.6 Requests	Original / Revised Compliance Date		Approved
1. Food Bank Discount – Annual to Monthly*	12/31/21	1/1/22	12/1/2021
2. PCIA on the Bundled Billing Statement – FR	12/1/21	10/1/23	11/2/21
3. AG-A (Legacy) Metered Demand – FR	3/1/22	3/31/25	11/24/21
4. Master Meter Version of E-TOU-C*	1/1/23	10/1/23	4/24/22
5. E-ELEC for Simple Legacy NEM & PS in ABS - FR	12/31/23	1/1/24	4/26/23
6. E-ELEC for Complex Legacy NEM in ABS - FR	12/31/23	12/31/24	4/26/23
7. BEV RTP Rate - FR	10/31/23	2/28/24	4/26/23
8. BEV Non-NEM Export Pilot (RTP) - FR	10/31/23	2/28/24	4/26/23
9. GRC 2 RTP Pilot Rates - FR	10/31/23	2/28/24	4/26/23
10. Medical Discount for EV2-A customers* - FR	12/31/23	12/1/24	4/26/23
11. PCIA on the Bundled Billing Statement – SR	10/1/23	12/31/27	4/26/23
12. GRC 2 Pilot Rates - SR	2/28/24	2/28/25	12/11/23
13. NBT Phase 1 – Residential*	12/15/23	4/1/24	12/14/23
14. E-ELEC for Simple Legacy NEM & PS in ABS – SR	1/1/24	10/1/24	12/26/23
15. NBT PS billed as NBT in CC&B (Advice Letter)	4/15/24	4/15/24	4/14/24
16. NBT for SmartRate	4/15/24	7/1/25	4/8/24
17. NBT for Non-SmartMeter Customers in ABS	4/15/24	12/31/25	4/8/24
18. BEV RTP Rate - SR	2/28/24	2/28/25	2/28/24
19. BEV Non-NEM Export Pilot (RTP) - SR	2/28/24	2/28/25	2/28/24
20. NBT Phase 2 – Non-Residential	6/30/24	3/2026	6/20/24
21. E-ELEC for Simple Legacy NEM & PS in ABS - TR	12/31/24	1/2026	9/19/24
22. E-ELEC for Complex Legacy NEM in ABS - SR	12/31/24	9/2027	9/19/24
23. GRC 2 RTP Pilot Rates – TR	2/28/25	2/28/26	3/3/25
24. BEV RTP Rate - TR	2/28/25	2/28/26	2/20/25
25. BEV Non-NEM Export Pilot (RTP) - TR	2/28/25	2/28/26	2/20/25
26. AG-A (Legacy) Metered Demand – SR	3/2025	12/31/27	2/27/25
27. NBT Phase 3 - NBT-Virtual and NBT-Aggregation - FR	6/30/25	9/30/26	6/30/25

ABS – Advanced Billing System (Legacy)
CC&B – Customer Care & Billing System (Legacy)
PCIA – Power Charge Indifference Adjustment
BEV – Business Electric Vehicle
RTP – Real Time Pricing
NEM – Net Energy Metering (Legacy Solar)
NBT – Net Billing Tariff
V-NEM – Virtual NEM
NEM-A – NEM Aggregation
PS – Paired Storage

FR – First Request
SR – Second Request
TR – Third Request
4R – Fourth Request
*Completed

Planned Rule 16.6 Requests

1. NBT Phase 3 - NBT-A, NBT-V, and NBT-VDT - SR	9/30/26	1. GRC 2 RTP Pilot Rates – 4R	2/28/26
2. PCIA on the Bundled Billing Statement – TR	12/31/27	2. BEV RTP Rate - 4R	2/28/26
3. Modified Cost Allocation Method. for LSE Resource Adequacy	7/31/27	3. BEV Non-NEM Export Pilot (RTP) - 4R	2/28/26

4. Billing Modernization Conclusion

In summary, if the CPUC's decision in this 2023 GRC II proceeding were to adopt any new rate proposals that require structural changes to PG&E's billing systems, programming of some of these proposals may need to be delayed until after the Billing Modernization Initiative has been finalized, and then prioritized among the previously-adopted rate projects already in the rates implementation pipeline.

D. Marketing, Education, and Outreach [Witness: Jamie Chesler]

This testimony includes several proposals that require outreach to customers once the CPUC issues a final decision in this proceeding. PG&E's proposed changes to revenue allocations are intended to bring Residential, Agricultural, Commercial and Industrial, and Business Electric Vehicle (BEV) customer rates closer to their cost of service. These changes will require ME&O at varying levels depending on the outcomes adopted in the final decision. Proposals seeking to modify program parameters, rate eligibility, baseline naming, if approved, will require updates to customer support materials and program webpages, and in some instances, customer notifications will be necessary.

1. Summary of ME&O Proposals

PG&E identified a number of proposals that will need ME&O and/or changes to outreach materials if the proposals are adopted and implemented. For proposals that PG&E can identify the types of customer communications and/or outreach materials updates necessary, PG&E provides that information. However, there are some proposals across several customer classes that are intended to move customers' rates closer to the cost of service by making changes to time-of-use (TOU) tier differentials and revising customer charges. These proposals span Residential, Commercial and Industrial, Agricultural, and BEV customer classes. For these proposed changes, it is premature to identify specific ME&O that will be necessary until a final decision makes a determination of all rate-related changes that will impact the customer's bills so they can be analyzed and evaluated for ME&O needs holistically. For these proposals, PG&E has provided the high-level approach that will be taken for planning ME&O.

The ME&O Proposals below are organized into two sections. The first discusses PG&E's overall approach for determining the level of customer communications once all rate-related changes for each customer class are authorized. The second part provides proposals for which PG&E is already able to provide more specific details on the ME&O that will be needed.

a. Summary of ME&O Approach for Rate and Customer Charge Proposals Pending Decision Authorization for Each Customer Class

Once the final decision adopts final values for the Baseline Quantities (BQ), TOU/Tier differentials and customer charges for Commercial and Industrial, BEV, Agricultural, and Residential customer rates, PG&E will conduct bill impact analysis for these customer segments. The bill impact analysis for each group of customers will inform the ME&O plan, including but not limited to conducting outreach to significantly impacted customers to make them aware of the change(s), timing of outreach to communicate the changes, and what resources and tips are needed to help customers manage their energy bill. (Please see Section 2.a. below for further detail on PG&E's overall ME&O approach).

b. Summary of ME&O Proposals With Identified ME&O Needs

The planned ME&O for more fully known proposals within PG&E's GRC II rate proposals, if adopted, includes:

1) <u>All-Electric Baseline Name Change (Residential)</u>: If PG&E's proposal to change the name "All-Electric Baseline" to "Electric Space Heating Baseline,"[9] is adopted, PG&E plans to communicate the change via a bill message. The bill message will explain the name change once the billing system update occurs and the revised name is shown on customers' bills. (Please see section 2.b.1. below, for additional details).
2) <u>Schedule Electric Vehicle (EV)2 (Residential)</u>: If PG&E's proposal to remove the requirement for customers' usage to be under 800 percent of their baseline to remain eligible for the EV2 rate is adopted,[10] PG&E plans to update rate materials and revise the rate description on PG&Es website. PG&E also plans to notify customers who were previously removed from EV2 for exceeding the 800 percent baseline threshold to offer them the opportunity to

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9 See Re-Label All-Electric Baseline in Section E.3. Chapter 3 of this exhibit (PG&E-3).

10 See EV2 proposal in Chapter 3, Section G.6 of this exhibit (PG&E-3).

return to service under this rate, if desired. (Please see Section 2.b.2. below, for additional details).

3) SmartRate™ (Residential): If PG&E's SmartRate proposal to eliminate the required nine SmartDay events minimum per year is adopted,[11] PG&E plans to notify enrolled customers of the change through regularly conducted pre-season communications; program marketing materials and PG&E's SmartRate Program webpage will also be updated accordingly. (Please see Section 2.b.3. below, for additional details).

4) Sunset legacy treatment for large customers on Rate Schedules A-6 and B-6 (C&I): If PG&E's proposal to eliminate the legacy exemption for Commercial and Industrial NEM customers who exceed 75 kilowatts (kW) is adopted,[12] PG&E plans to notify the NEM customers who exceed 75 kW that they will be transitioned to a different rate that meets their demand usage. (Please see Section 2.b.4. below, for additional ME&O details).

2. ME&O Proposals

a. ME&O Approach for Rate and Customer Charge Proposals Pending Decision Authorization for Each Customer Class

The final rate differentials and customer charges that will be adopted in the decision in this 2023 GRC II proceeding provide critical data necessary to determine the appropriate ME&O that is needed to help affected customer classes understand and prepare for the change(s). To effectively determine the level of outreach needed for all customers affected by the change(s) and those who fall in the spectrum of positively or negatively impacted, PG&E will conduct a billing analysis after the CPUC issues the final decision for this proceeding. The rates and customer charges adopted, or in cases where only partial proposals are ultimately adopted, will result in customers with varying bill impacts.

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11 See SmartRate proposal in Chapter 3, Section H of this exhibit (PG&E-3).

12 See Sunset 75 kW Legacy Treatment of Large Customers on A-6/B-6 in Chapter 4, Section D (Rate Design for SLP) of this exhibit (PG&E-3).

1) Approach for Planning ME&O

ME&O is a key component to customer understanding and acceptance of upcoming rate changes. Customer communications are carefully planned to ensure that customers receive information at the right time, through the right channels commensurate with the level of changes and the quantity, and types of impacted customers.

At this time, it is premature to develop the ME&O plan and determine which channels should be utilized and at what advance timing before TOU differential changes are implemented. Customer communications will vary given the potential for wide variances in customer impacts if the price differentials are greater/smaller than proposed amounts or if only portions of proposals are adopted. Once the Commission's final decision is issued and calculations are made to determine the exact Peak to Off-Peak (POP) price differentials and revised non-residential customer charges, PG&E will utilize the analysis of expected customer impacts to determine the most appropriate timing and tactics for notifying customers.

PG&E's ME&O plan will leverage significant learning and experience in creating awareness and successfully transitioning customers to new rate structures gained over the last decade. PG&E has transitioned non-residential customers from flat rates to TOU rates and from TOU rates to Peak Day Pricing (PDP) rates. Throughout the TOU and PDP transitions, PG&E conducted research that validated customer awareness and understanding of the transition and how the new rates functioned. PG&E has also transitioned residential customers from tiered rate schedules to TOU rates and is preparing to educate customers on a fixed charge to be implemented in 2026. These transitions were large and required significant education in advance and during the transition period. In addition to these large transitions to completely new rate structures, PG&E regularly communicates with customers when annual rate changes occur.

2) Customer Classes with Proposed Changes

The following customer classes have proposals that will require further analysis to identify what outreach is recommended.

<u>Residential Customers</u>:

i) <u>Tiered Rates</u>: Reduce tier differentials;

ii) <u>TOU Rates</u>: Update TOU price differentials;

iii) BQ updates; and

iv) Revise Diversity Benefit Adjustments for mobile home park and multifamily dwellings (Schedules ET and ES).

<u>Commercial and Industrial Customers</u>:

i) Increase customer charge to better reflect marginal costs; decrease volumetric energy and demand charges;

ii) Increase cost basis for TOU rate differentials—widens most peak to off peak period TOU differentials; and

iii) Sunset 75 kW legacy treatment of customers on A6 and B6.

<u>Agricultural Customers</u>:

i) Increase customer charge to better reflect marginal costs;

ii) Decrease volumetric energy and demand charges;

iii) Widen summer POP period TOU differentials; and

iv) Increase Demand Charge Rate Limiter.

<u>BEV Customers</u>:

i) Increase in distribution rates;

ii) Decrease in generation rates;

iii) Increases in subscription rates; and

iv) Reduce POP period TOU differentials.

3) Bill Impact Analysis

Once the CPUC issues final approved rate changes and customer charges, PG&E will perform a detailed analysis to evaluate the overall impact to customers' bills. This evaluation allows PG&E to determine how many customers will be impacted within each customer class, how many customers are expected to see a positive impact (bill reduction), neutral impact (bill stays in the same range), or negative impact (bill significantly increases). The results of this analysis will allow PG&E to: (1) segment the target audiences within each of the customer classes; and (2) determine the right level and frequency of customer communications to be delivered in advance to help customers prepare for the upcoming changes.

4) Customer Outreach

As mentioned, PG&E's ME&O plan will be tailored to provide customer communications with the right level of information, at the right time and through the right channels based on the positive, neutral, and negative impact of the authorized changes. The plan will vary to ensure that customers with more significant bill impacts will receive additional communications with advance notice to help create awareness of the change, information about how they can prepare for the change, provide additional resources to avoid high bill surprises and manage their energy use such as bill forecast alerts and cost and usage tools.

PG&E's outreach strategy will likely include a combination of the tactics below, although one or more tactics may not be used for a specific class:

- Direct-to-customer communications such as direct mail or e-mail;
- On bill messaging or bill insert;
- Webpage(s) that provide additional information about the change;
- Digital newsletters or other integrated communications as appropriate; and
- Account Representatives may conduct person-to-person outreach to their already assigned customers if they are projected to be among the most highly impacted.

5) Resources to Develop and Implement the ME&O Plan

PG&E cannot determine the exact funding necessary for the outreach plan. To determine appropriate resourcing, PG&E must have a full understanding of the approved rates for all proposed customer classes, and how many customers and to what level they can expect positive, neutral or negative bill impacts. PG&E will seek funding authorization in PG&Es 2027 GRC Phase I to fund the development of outreach materials, execute outreach, and support continually evaluating the effectiveness of customer communications to allow for adjustment as needed.

b. Planned ME&O for All-Electric Baseline, Rate Eligibility EV2 & E-ELEC, and SmartRate

1) Re-Label “All-Electric” Baseline to “Electric Space Heating” Baseline (Residential)

As described in Chapter 3 of this exhibit, PG&E proposes to relabel the “All-Electric” BQs to “Electric Space Heating” BQs to avoid customer confusion and encourage electrification efforts. Despite the “all-electric” BQs name, customers are not required to have all-electric homes to qualify for the “All-Electric” BQ. Rather, a customer only needs to use permanent electric space heating for their primary space heating needs. The term “All-Electric” baseline level dates back to when EVs, heat pump water heaters and electric stoves were not as common and has taken on a different meaning now that customers are purchasing multiple home electrification technologies.

Relabeling to “Electric Space Heating” BQ will help customers from assuming a rate with an “All-Electric” BQ is the only rate or is the best rate if they completely electrify their home when they may benefit from a non-tiered rate such as Schedule E-ELEC.

If PG&E’s proposal in Chapter 3 to re-label “All-Electric” baseline to “Electric Space Heating” baseline is approved, PG&E plans to provide bill messaging to explain this is a name change that will appear on customers’ bills at the time the reprogramed name is implemented. PG&E will also update existing electrification marketing materials and corresponding online baseline allowance webpages to reflect the change.

2) <u>Residential Rate Eligibility</u>: Remove 800 Percent of Baseline Usage Limit for EV2 and Remove E-ELEC Technology Requirements

As described in Chapter 3 of this exhibit, PG&E proposes to remove Schedule EV2's requirement that customers must remain under 800 percent of their baseline to remain eligible for the rate. This change aligns with our state's electrification/decarbonization policy and will improve the customer experience for EV customers who may charge more than one EV on their premise and may also install other new electrification appliances, to retain their eligibility for the EV2 rate. Once this proposal is approved, PGE.com will be updated to remove the requirement to use less than 800 percent of their BQ to remain eligible for the rate. Customers who became ineligible and were removed from the EV2 rate for exceeding 800 percent of their BQ will be notified of the EV2 eligibility changes. These customers will be advised of the opportunity to opt into the Schedule EV2 again (or Schedule E-ELEC), whichever may best suit their current needs.

As described in Chapter 3 and Chapter 10, PG&E proposes to eliminate the requirement for qualifying technology (specifically, electric vehicles, energy storage, and electric heat pumps) to be eligible for the E-ELEC rate schedule for customers on RTP.[13] Once PG&E's proposal is approved, PGE.com and customer program materials will be updated to remove the technology requirements if the customer elects RTP from E-ELEC.

3) SmartRate: Eliminate Minimum SmartDay Requirements

Customers who voluntarily enrolled in PG&E's SmartRate™ Program will see a minor change to the program if the CPUC approves PG&E's proposal. The program as currently approved calls a minimum of nine and a maximum of fifteen SmartDay events per year. As described in Chapter 3 of this exhibit, PG&E proposes to eliminate the nine SmartDay event minimum. In mild summers, there may not be a need for nine events. This change prevents customers being asked to

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[13] See Eligibility in Chapter 10, Section K of this exhibit (PG&E-3).

conserve energy on a SmartDay when load reduction is not necessary. PG&E's proposal does not seek to modify the maximum of 15 events per year.

SmartRate outreach materials, seasonal communications and PGE.com SmartRate webpage description of the program will be revised to remove the reference to a minimum of nine events per year. Current SmartRate customers will be informed of the minor program change through the seasonal program communication they already receive.

4) Sunset 75 kW Legacy Treatment on Schedules A6 and B6

As proposed in Chapter 4 of this exhibit, PG&E proposes to sunset the legacy treatment of customers on Schedules A6 and B6 who have remained on the rate schedules under a legacy exemption that allows exceeding the—75 kW—eligibility requirement.[14] PG&E proposes to adopt December 31, 2027 for public agencies and July 31, 2027 for all other nonresidential customers as an expiration date for the 75 kW Legacy Treatment. As of June 2024, there are about 2,000 customers enrolled in Schedules A-6 or B-6 with demand exceeding 75 kW. These customers will be notified at least one month in advance of the transition, via channels such as direct mail and e-mail. Communications will explain the end of the legacy treatment, provide the planned sunset date and inform the customer of the rate schedule they will be transitioned to that aligns with their demand.

E. Conclusion

1. Billing Modernization Initiative and Constraints on Billing System Structural Changes [Witness: Emily Bartman]

Due to PG&E's multi-year Billing Modernization Initiative and existing pipeline of already-approved rate projects, if the CPUC's decision in this 2023 GRC II proceeding were to adopt any new rate proposals that require structural changes to PG&E's billing systems, programming of some of these proposals may need to be delayed until after the Billing Modernization

[14] See Proposal in Chapter 4, Section D.4 of this exhibit (PG&E-3).

Initiative has been finalized, and then prioritized among the previously-adopted rate projects already in the rates implementation pipeline.

2. Marketing, Education, and Outreach [Witness: Jamie Chesler]

PG&E's ME&O plan, for this 2023 GRC II proceeding, will leverage our extensive experience supporting customers through rate structure transitions and rate changes. Development of more detailed outreach plans will rely on evaluation of bill impacts from approved changes, to arrive at a plan designed to increase customers' understanding and awareness of changes to their bill, the timing of such changes, and provide customers with resources to help them effectively manage their energy use and bills, accordingly.