2025 SENATE BILL 695 REPORT

Report to the Governor and Legislature on Actions to Limit Utility Cost and Rate Increases Pursuant to Public Utilities Code Section 913.1

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Cover Photo: Person holding a device with an energy management program displayed.

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I. Executive Summary

The California Public Utilities Commission (CPUC) issues this 2025 Senate Bill (SB) 695 Report pursuant to Public Utilities Code Section 913.1. This report outlines the primary cost drivers for California's Investor-Owned Utilities (IOUs)[1]. The same statute requires the IOUs to propose measures to control costs and rate increases.[2]

The CPUC's mission is to ensure that California IOU customers receive safe, reliable, and clean utility service at just and reasonable rates. Determining these rates involves complex electric and gas ratemaking processes, which scrutinize various IOU requests for capital investments, expenses, and other essential costs and distill these costs into an approved revenue requirement collected from customers so that Californians receive safe and reliable energy at least cost. The CPUC continues to further the goals of affordable rates and bills as well as safe, reliable, and clean utility service through every aspect of its regulatory oversight, including its design and implementation of supply and demand-side energy programs.

We are in a transformative period: the electrical grid is increasing served by low-cost clean electricity and electricity demand is increasing at an unprecedented rate due to transportation and building electrification and the growth of data centers and large customer loads. Recognizing the impacts new loads will have on the distribution grid, the CPUC recently ordered the IOUs to modernize how they plan for infrastructure investments so that the grid can accommodate electric vehicles, electric heat pumps, and data centers in a more efficient, cost-effective way. While costs to upgrade the electric distribution system will be in the tens of billions of dollars over the medium-term, these strategic investments also come with the opportunity to share system costs among more units of electricity consumed and provide a means to pay off the infrastructure investments over time. Increased electricity demand from emerging new large businesses and customers who electrify their homes and vehicles can put downward pressure on everyone's electric rates. Efficient short and long-term planning will be key to guiding future grid investments and realizing significant public benefits as fewer cars, trucks, and buildings rely on fossil fuels for energy.

During this period of transition, it remains imperative that California has a system to deliver clean, reliable, and safe electricity and natural gas to customers as cheaply as possible. The main way the CPUC contains costs is through the General Rate Cases (GRC) for each utility. During the GRC process, CPUC staff and stakeholders apply rigorous scrutiny to costs and proposed investments submitted by each utility in a comprehensive filing. This enterprise-wide review is designed as the best way to impose discipline on

[1] The IOUs subject to this statutory requirement are Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), and Southern California Gas Company (SoCalGas). These large electric and natural gas IOUs fall under the reporting requirements of Public Utilities Code Sections 913.1. The CPUC also regulates several smaller IOUs that do not fall under the reporting requirements of Public Utilities Code Sections 913.1.

[2] Public Utilities Code §913.1(a) requires the CPUC to publish recommendations that can be undertaken over the succeeding 12 months to limit California's IOU cost and rate increases consistent with the state's energy and environmental goals. Public Utilities Code §913.1(b) requires electrical corporations with 1,000,000 or more retail customers in California, and gas corporations with 500,000 or more retail customers in California, to study and report on measures the corporation recommends be undertaken to limit cost and rate increases.

spending and transparently identify both opportunities to avoid investments wherever possible and the most cost-effective options for investments needed to serve customer load.

The CPUC requires the large energy utilities to file a GRC for forecasted electricity and gas costs every four years. Through the GRCs, the CPUC determines the revenues that are necessary for the upcoming four-year period at the lowest just and reasonable rates. With extensive input from outside parties, the Commission reviews the utility's application and conducts an in-depth examination of the utility's investments and expenses forecast. The result is a determination of the utilities' revenue requirement and the least cost pathway to achieving safe, reliable, affordable, and clean gas and electric service. The CPUC then oversees the implementation of the GRC through many proceedings and programs, striving for cost containment wherever possible.

Utility Rates Continue to Trend Above Inflation

Starting in 2021, bundled system average rate (SAR) increases began to outpace inflation for the three large electric IOUs. This report finds that electric bundled residential average annual rate (RAR) increases over the period 2016 – 2024 were about 11 percent, 8 percent, and 7 percent for PG&E, SCE, and SDG&E, respectively, compared to an inflation rate of 3.5 percent over the same period and are expected to continue increasing above inflation through 2028.[3] Average annual electric bundled RAR increases over the period 2025 – 2028 are forecast to be about 6 percent for PG&E and SDG&E and about 7 percent for SCE, compared to an assumed inflation rate of 2.6 percent over the same period.

The Largest Contributors to Rising Electricity Rates Are Wildfire-Related Costs, Rooftop Solar Program Costs and Cost Shifts, and Increased Investment in Distribution Infrastructure

This report identifies three primary drivers of increased costs: wildfire-related expenses, rooftop solar incentives, and higher investments in distribution infrastructure.

Wildfire-Related Costs

- Wildfire-related revenue requirement in 2024 made up about 27 percent of PG&E's total revenue requirement and 17 percent respectively of SCE and SDG&E's total revenue requirements, [4] translating to an average annual cost of roughly $250 to $490 for residential customers.[5]

[3] Based on rates at year-end. Forecasts are conducted through 2028 because projected revenue changes that inform forecasts are based on rolling four-year-cycles, which generally align with at least one utility's general rate case.

[4] At year-end 2024. Year-end revenue requirement data may not represent revenue requirement over the full course of the year. For example, revenue requirement implemented after January 1 will not reflect a full year of being in rates.

[5] Typical customer using 500 kWh (PG&E climate zone X, SCE climate zone 9) and 400 kWh (SDG&E Inland climate zone).

- Total wildfire mitigation and wildfire liability costs[6] (collectively, "wildfire-related costs") authorized for recovery between 2019 and 2024 are approximately $40 billion, resulting in an equivalent revenue requirement over this time period of about $27 billion.[7]
- Wildfire mitigation costs, driven in part by climate change, are projected to continue their upward trend as indicated in the 2026 – 2029 wildfire management plans (WMPs) recently filed by the IOUs with the Office of Energy Infrastructure Safety (Energy Safety).[8]

Rooftop Solar-Related Costs

The NEM 1.0, NEM 2.0, and Net Billing Tariff programs (collectively, the rooftop solar program) increase electricity bills in two ways:

- Customers pay for the generation that is exported to the grid from another customer's rooftop solar system at a higher rate than other available generation,[9] and
- The rooftop solar program allows customers to bypass their share of fixed costs to maintain the electric grid,[10] which other customers without rooftop solar end up paying.

These factors make the rooftop solar program the other largest single contributor to rising electricity rates:

- Data shows that rooftop solar program costs in 2024 resulted in about $7 billion shifted to customers without rooftop solar.[11]
- This cost estimate accounts for between 12 and 19 percent of the electricity bill of non-participating customers, depending on the IOU, which translates to an average annual cost of roughly $230 to $380 for customers without rooftop solar.[12]

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[6] Includes catastrophic events costs, which are substantially related to fire-related events but may include costs for other non-wildfire related events such as severe storms and wind events.

[7] The revenue requirements amounts are smaller than the corresponding authorized costs because capital-related costs, when converted to revenue requirement, go into rates gradually over a long period of time. While the annual depreciation amount in the revenue requirement corresponding to a capital asset is smaller than the cash outlay for the asset, capital-related costs ultimately result in greater expense to ratepayers due to the inclusion of the rate of return on the capital asset. *See* Chapter 2 for more information about how capital-related costs are converted to revenue requirement.

[8] Between PG&E and SCE's higher planned spending for the 2026 – 2028 WMP cycle than the approved spend in the previous WMP cycle and the possibility of significant electric undergrounding spend pursuant to SB 884, wildfire mitigation costs are expected to continue to grow.

[9] NEM 1.0 and NEM 2.0 programs only.

[10] After accounting for potential reductions in distribution, transmission, generation, and other costs.

[11] This amount is different from the 2024 NEM cost shift $8.5 billion calculated by the CPUC Public Advocates Office (Cal Advocates). *See* Cal Advocates' Fact Sheet, "The Rooftop Solar Dilemma" (December 2024). *See* also Chapter 4, "Net Energy Metering and Net Billing Tariffs Cost Impacts" for more information.

[12] Typical customer using 500 kWh (PG&E climate zone X, SCE climate zone 9) and 400 kWh (SDG&E Inland climate zone). The NEM program bill portion cannot be added to other estimated bill portions such as wildfire-related costs to calculate a total percentage representing these cost drivers as NEM cost shift data is not mutually exclusive with other rate components used to derive bill portions, particularly the distribution rate component through which much of the wildfire-related bill portion is calculated.

The CPUC has taken action to reduce the rooftop solar program's impact on rates:

- The NEM 2.0 tariff was discontinued for new customers following adoption of the Net Billing Tariff (NBT) in 2022. The NBT reduces the growth of future cost shifts by more closely aligning the amount paid to rooftop solar customers for excess generation with the value that excess generation provides. The NBT continues to allow rooftop solar customers to avoid fixed costs incurred to serve all customers, placing an ongoing burden on customers without rooftop solar.

Distribution System-Related Costs

The distribution revenue requirement has grown significantly over time, to more than double in 2025 what it was in 2016. The distribution revenue requirement includes costs for power lines, poles, transformers, repair crews and emergency services, as well as certain wildfire mitigation costs related to grid reliability and safety, including liability insurance. Rapid growth starting in 2021 reflects the wildfire-related distribution revenue requirement for vegetation management, infrastructure hardening, and wildfire insurance, among other costs.[13] Across the IOUs, once wildfire-related costs are removed, the remaining distribution system costs have risen at an annual average of approximately 11 percent since 2019.[14] Transportation and building electrification-related distribution capacity upgrade costs are not evaluated in this report since these emerging costs are either recently approved or currently being reviewed in active proceedings and the costs, at their approved revenue requirement equivalent, will be in rates at a future date.

Natural Gas Revenue Requirements Are Increasing

The combined gas revenue requirement of California's three largest gas utilities has increased by 72 percent this past decade. In 2025, the natural gas utilities' revenue requirements are forecasted to continue their decade-long upward trajectory. PG&E's, SoCalGas', and SDG&E's combined revenue requirements will increase by a cumulative 5.6 percent, from $13,667 million in 2024 to $14,427 million in 2025.[15] The combined 2025 revenue requirements will fund the operation of seven gas storage facilities and approximately 10,100 miles of large diameter, high pressure, gas transmission pipelines that connect to the 103,617 miles of smaller diameter, lower pressure, gas distribution pipelines serving approximately 11.5 million natural gas meters.[16]

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[13] Other wildfire-related distribution costs include other wildfire mitigation costs, for example situational awareness costs, as well as other wildfire recovery costs such as catastrophic events costs. *See* Chapter 4, "Wildfire-Related Cost Impacts" for more information.

[14] Average annual percent changes throughout this report are based on a simple, smoothing calculation of: (end of period value – beginning of period value)/number of periods where 'periods' is defined as a range of years.

[15] The utility-specific year-over-year revenue requirement increases are 11.3 percent for PG&E (from $6,260 million to $6,966 million); 0.2 percent for SoCalGas (from $6,440 million to $6,455 million), and 4.0 percent for SDG&E (from $967 million to $1,006 million).

[16] Sources: PG&E's 2023 Gas Safety Plan; Exhibits SCG-04-R-E, SCG-06-2R-E, SCG-10-R, SDGE-04 and SDGE-06 of Application 22-05-015/-016 (Sempra 2024 GRC).

CPUC Executive Order N-5-24 Response Offers Options to Save Ratepayers Money Going Forward

On February 18, 2025, the CPUC released its response to Governor Newsom's Executive Order (EO) N-5-24 to address the imperative set forth in the executive order to mitigate the rising costs of electricity service in California. [17]

The EO response identifies several ways the CPUC is evaluating cost containment opportunities consistent with the CPUC's commitment to ensure just and reasonable rates while promoting reliable, affordable, and clean utility services:

- **Mitigate Cost Increases:** Implementing measures to control rising costs.
- **Focus on Equitable Cost Allocation:** Seeking ways to distribute energy costs more fairly and enhance equity for low-income customers, tribal communities, and disadvantaged communities.
- **Assess Cost Effectiveness:** Evaluating program costs and benefits with the goal of achieving the lowest possible rates for all customers.

These objectives and cost containment opportunities from the EO Response are summarized below.

[17] *See* the CPUC's EO N-5-24 Response. Portions of the EO N-5-24 Response are reproduced in whole or in part in this report.

CPUC Recommendations for Cost Containment

Mitigate Cost Increases: Identify Cost Reduction Measures from Integrating All Wildfire Mitigation Plans (WMP) into the General Rate Case (GRC) Process

- The Public Utilities Code could be amended to modify provisions that allow IOUs to record WMP-related costs to memorandum accounts and instead provide the CPUC with discretion to approve memorandum accounts, aligning WMP-related costs to the same regulatory cost recovery mechanisms as for other business planning processes (i.e. the GRC process).
- While existing CPUC directives require that costs stemming from an approved WMP be tracked and clearly identified in the GRC, the Legislature has required the CPUC to grant any utility request to track and seek recovery of costs that exceed forecasted GRC costs. The Legislature could revise the statutory mandate so that all WMP costs can be included and mapped to the GRC;[18] so that utilities would need to include their entire forecasted amounts in GRC applications.19

Consider How to Improve the Effectiveness of California Climate Credit (CCC) Allocation

- The CCC could be reallocated to customers who need it the most, for example, to all customers who receive the CARE benefit. It could also be supplemented with non-ratepayer funding.
- Alternatively, the CCC presents an opportunity to make electrification more appealing to all ratepayers if, rather than being distributed in a lump sum, it could be allocated on the basis of usage, which would reduce the volumetric rate for electricity.
- An Order Instituting Rulemaking (OIR) was issued in July 2025 to consider ways to improve the effectiveness of the California Climate Credit for supporting customer affordability, among other considerations.20

Assess Cost Effectiveness: Review Programs to Ensure Goal Achievement at the Lowest Cost for All Ratepayers

- The EO Response includes a list of programs along with an indication of whether a cost effectiveness review has been conducted for each.21

[18] All CPUC-jurisdictional costs.

[19] There could be a comprehensive mapping of the WMP costs to the GRC that includes the GRC costs plus explanatory inclusion of all other non-GRC cost mapping, which may include historical costs, that consolidates to the total WMP costs.

[20] *See* Rulemaking (R.)25-07-013.

[21] *See* Table A-2 in the CPUC's EO N-5-24 Response.

II. Background

The CPUC regulates electric service of nearly 12.5 million customer accounts served by PG&E, SCE, and SDG&E as well as the gas service of nearly 11.5 million customer accounts served by PG&E, SoCalGas, and SDG&E.[22] While the Public Utilities Codes mandates requirements related to safety, reliability, and just and reasonable rates, in this report, cost-of-service rate regulation is the focus. In cost-of-service rate regulation, the regulator determines the total amount of money that must be collected in rates for the utility to recover its reasonable and necessary costs plus the opportunity to earn a reasonable return on investments. The cost-of-service regulatory model aims to provide universal access to safe and reliable electricity and natural gas while creating an oversight regime so that regulated monopoly utility service providers charge a fair price.

Electric Costs, Revenue Requirement, and Rates

Utilities file detailed descriptions of the costs of providing service (also referred to as "revenue requirements") and request authorization to collect revenue requirements in various ratesetting proceedings. Most utility costs, other than the cost of procuring fuel and purchased power, are generally addressed in General Rate Case (GRC) proceedings.[23] GRCs are forward-looking, as IOUs forecast and estimate their anticipated costs to operate their respective utility. In GRC proceedings, the CPUC sets a pre-specified revenue requirement for the first year in the cycle, or "test year," with formulaic adjustments for the subsequent "attrition years" until the next GRC cycle commences.

In addition to forecasting costs for recovery, GRCs may include requests for recovery of costs that have already been incurred i.e., recorded costs in balancing accounts and memorandum accounts.[24] A balancing account is established to record certain authorized costs for recovery through rates and to ensure the revenue collected matches the authorized amounts. Balancing account revenue balances are to be returned to ratepayers if the account is over-collected, and in some circumstances additional revenue can be recovered from ratepayers if the account is under-collected.[25] Memorandum accounts are similar to balancing accounts except they record costs not yet authorized and are subject to reasonableness reviews by the CPUC and may or may not be recoverable through rates. Memorandum accounts generally reflect unanticipated costs such as the cost of restoring service after a catastrophic event or the costs associated with new legislation enacted after a utility's GRC proceeding.

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[22] In 2024, the electric IOUs had an average customer count of: PG&E 5.7 million; SCE 5.3 million; and SDG&E 1.5 million. According to the 2022 California Gas Report, SoCalGas had 5.9 million customers, PG&E had 4.5 million, and SDG&E had 0.9 million.

[23] For more detailed descriptions of how GRC and other proceedings authorize utility revenue requirements, *see* the 2024 Assembly Bill (AB) 67 Report available here.

[24] Cost recovery of balancing and memorandum account balances may also occur outside GRC proceedings.

[25] Under-collected balancing account balances can only be recovered from ratepayers if the balancing account is a two-way balancing account. Under-collections in one-way balancing accounts cannot be recovered from ratepayers.

The cost of energy procurement and return of greenhouse gas (GHG) auction proceeds are generally addressed in annual Energy Resource Recovery Account (ERRA) Forecast proceedings. ERRA costs are pass-through expenses–the utility receives no mark up or profit on these costs. Utilities may periodically also be directed by the CPUC to file applications pursuant to legislative mandates. For example, Energy Efficiency Portfolio applications are periodically filed to request energy efficiency funding.

The CPUC authorizes the revenue collected from customers by one or more rate components corresponding to a functional area of utility operations (i.e., generation, distribution, transmission, etc.). Electric IOU customers generally see customer bills organized by a generation rate and a delivery rate, with the delivery rate including all other non-generation rates including distribution, transmission, and the non-bypassable costs of public purpose programs (PPP) that are paid by all customers who use the utility delivery system.

The **generation** rate component collects the revenue requirement corresponding to generation portfolio costs. This rate component recovers the cost of Utility Owned Generation (UOG), consisting of fuel and other operating expense and capital costs associated with generation plants such as nuclear, gas, and hydroelectric. IOUs also recover "purchased power costs" which represent the costs of contracts with third-party electricity generators. The incremental cost impact of renewable contracts to meet the Renewables Portfolio Standard (RPS) and GHG costs[26] is also reflected in generation rates. In addition to the cost of energy, the generation rate includes generation capacity costs to ensure energy is available wherever needed on demand—even if not used.[27]

The **distribution** rate component collects the revenue requirement corresponding to operating expense and capital costs associated with distribution service. This rate component recovers the costs to distribute power wherever and whenever it is needed and includes power lines, poles, transformers, repair crews and emergency services, as well as certain wildfire mitigation costs related to grid reliability and safety. In addition, the CPUC has authorized the IOUs to recover funding related to specific public policy objectives such as transportation electrification and demand response through the distribution rate component.

The **transmission** rate component collects the revenue requirement associated with the utilities' assets determined to be part of the interstate transmission system. Transmission rates are primarily set by the Federal Energy Regulatory Commission (FERC) in Transmission Owner (TO) rate cases, in which the CPUC represents California retail ratepayers as an advocate for just and reasonable transmission rates. The overall transmission rate is comprised of four sub-components: (1) Base Transmission Revenue Requirement, which is set in TO rate cases and recovers the costs associated with transmission assets under ISO operational control and subject to FERC's jurisdiction; (2) transmission revenues that flow to retail customers from others' use of the transmission system, primarily wheeling power through the CAISO grid;

[26] Since January 1, 2013, electric utilities have been regulated under California's Greenhouse Gas Cap-and-Trade Program. Beginning in 2014, the electric utilities started introducing Cap-and-Trade Program related costs into electricity rates. The majority of the allowance proceeds are returned to residential customers via the California Climate Credit, applied to the distribution component of customer bills twice per year.

[27] For example, *see* "Bundled Residential Generation Rate" in Chapter 4 for more information on Resource Adequacy (RA) contracts that a utility must buy to meet its reliability requirements.

(3) Reliability Services costs related to contracts signed by the California Independent System Operator (CAISO) with certain generators needed to maintain system reliability; and (4) the Transmission Access Charge Balancing Account Adjustment, which accounts for the over- or under-collection of what the IOU receives for the cost of operating its high voltage assets compared to what it has to pay for its use of the CAISO-controlled regional high voltage grid.

Other rate components include:

- Public Purpose Programs (PPP),
- New System Generation (NSG),
- Competition Transition Charge (CTC)
- Nuclear Decommissioning (ND),
- Wildfire Fund Charge (WFC),
- Wildfire Bond Securitization Fixed Recovery Charge (FRC)
- Total Rate Adjustment Component (TRAC), and
- Energy Crisis Refund Adjustment (ECRA).

The **PPP** rate component collects program funding authorized by the CPUC for Electric Program Investment Charge (EPIC), Energy Efficiency, Low-Income programs, and other public policy programs.[28] **NSG** charges recover the costs of "new generation" assets the IOUs procure to maintain system reliability. **CTC** recovers above-market costs associated with power purchase contract obligations that resulted from electric industry restructuring.[29] **ND** costs flow into a trust maintained for assurance that complete decommissioning activities for nuclear facilities will be undertaken and are recovered separately in the ND rate component. **WFC** recover costs to fund the wildfire fund created by Assembly Bill (AB) 1054 (Holden, 2019).[30] Wildfire Bond Securitization **FRC** are charges for certain wildfire capital costs recovery bonds that AB 1054 permits to be securitized through a CPUC financing order rather than being financed through the more traditional unsecured bond offerings.[31] The **TRAC** reflects the cost shift that resulted from capped residential tiered rates previously legislated under AB 1X and SB 695.[32] The **ECRA** rate component is used to return amounts to customers resulting from settlement agreements with sellers of energy to resolve energy claims related to the Western Energy Crisis of 2000-2001 ("FERC energy crisis refund).[33]

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[28] For more detailed descriptions of PPP, *see* the 2024 AB 67 Report available here.

[29] Restructuring was pursuant to Public Utilities Code Section 367(a).

[30] Starting October 2020. Prior to October 2020, the non-bypassable charge was known as the Department of Water Resources (DWR) Bond Charge for the repayment of bonds issued in 2003 to recover the costs incurred by the State of California to purchase power during the energy crisis.

[31] PG&E and SCE currently have AB 1054 securitizations that are recovered through a non-bypassable fixed recovery charge.

[32] Applies to SDG&E only.

[33] Applies to PG&E only.

The generation and delivery rates can be combined into one overall rate: at system level for all customer classes or at customer class level, such as residential class level. **Bundled system average rate (SAR)** is a high-level measure of an IOU's authorized bundled[34] customer revenue requirement expected to be recouped through authorized forecasted sales to bundled customers. **Bundled residential average rate (RAR)** is determined in a similar manner to bundled SAR, except that instead of using system-level (i.e., all) bundled revenue requirement and bundled system-level forecasted sales, the revenue requirement is allocated to the bundled residential class and bundled residential class forecasted sales are used. Residential tariffs are then designed to collect the revenue requirement based on the forecasted sales reflected in the RAR.

Bundled Average Rates

$$\text{Bundled SAR} = \frac{\text{Bundled customers authorized revenue requirement (\$)}}{\text{Bundled authorized forecasted sales (kWh)}}$$

$$\text{Bundled RAR} = \frac{\text{Bundled residential customers authorized revenue requirement (\$)}}{\text{Bundled residential authorized forecasted sales (kWh)}}$$

Natural Gas Costs, Revenue Requirement, and Rates

Critical elements of the Public Utilities Code related to gas services require that the CPUC:

1. Evaluate the reasonableness of natural gas rates and rate changes;
2. Oversee Core Transport Agent (CTA) rules[35] and consumer protection matters;
3. Oversee the adoption of standards and incentives for biomethane production;
4. Oversee the implementation of utilities' Pipeline Safety Enhancement Plans (PSEP) to pressure test or replace all intrastate transmission pipelines that do not have a record of a pressure test;[36]
5. Determine the feasibility of minimizing or eliminating use of SoCalGas's Aliso Canyon gas storage facility while still preserving energy reliability;[37] and
6. Create a path to transition away from fossil gas while maintaining safety, reliability, and just and reasonable rates.[38]

[34] Bundled IOU customers take all services–generation, transmission, and distribution services–from the IOU.

[35] Core Transport Agents (CTA) procure the gas commodity for core customers such as residential and small commercial customers as an alternative to the utility. CTA customers pay the utility for transportation of the commodity. The CPUC does not regulate the rates CTAs charge their customers. However, CTAs are required to register with the CPUC, and the agency has the power to revoke a CTA's license. The CPUC receives and investigates complaints against the CTAs.

[36] Public Utilities Code Section 958.

[37] Public Utilities Code Section 714.

[38] Public Utilities Code Section 38562.2 and Public Utilities Code Section 454.53.

These mandates are reflected in formal rate cases, cost allocation proceedings, renewable gas efforts, and safety-oriented proceedings.

As with the electric utilities, the GRC establishes the authorized annual revenue required for a utility to recover its costs of serving customers and a fair return or profit on its investments for shareholders. The revenue authorized in a utility's GRC (called "revenue requirement") covers the day-to-day operating costs of running the utility system, administrative and general expenses, depreciation of capital investments in facilities and assets over their useful lives, taxes, and a rate of return on invested capital.

Gas customers are divided into two main categories–core and noncore customers. Residential and small commercial customers generally fall into the core category. The utilities are responsible for procuring and delivering natural gas to most core customers. However, some core customers choose to have a third-party CTA procure natural gas for them. Noncore customers are large commercial and industrial customers, including electric generators, refineries, hospitals, and manufacturers. Noncore customers make their own arrangements to procure natural gas and rely on the utilities for the delivery of the commodity.

Natural gas utility costs may be categorized into three main components: 1) core procurement costs,[39] 2) costs of operating the natural gas transportation system and providing customer service, and 3) costs associated with gas public purpose programs (PPP). Core gas procurement commodity costs are passed directly on to gas customers with no markup and are recovered in utility gas procurement rates, which are adjusted monthly to reflect changes in the market price.[40] The other two components of natural gas utility costs are typically addressed in GRCs and other cost recovery proceedings. These proceedings have several objectives, among them: setting rates as low as possible while yielding revenues that cover the utilities' costs; maintaining safe and reliable service; and promoting energy conservation and greenhouse gas (GHG) reduction.

Bundled[41] gas rates are impacted by the following: 1) changes to revenue requirement, which are mostly determined in GRCs, 2) changes to forecasted sales demand, which are determined in cost allocation proceedings, and 3) core procurement costs adjusted monthly through advice letters filed by the IOUs. The rates paid by individual customers are also impacted by how the revenue requirement is allocated among customer classes in the cost allocation proceedings.[42] Gas revenue requirements and rates can also be

[39] Includes the monthly weighted average cost (WACOG) of gas, interstate and intrastate pipeline capacity costs, storage costs (PG&E only), hedging costs (winter only), shrinkage costs, franchise fees & uncollectibles, and brokerage fees.

[40] The utilities' gas procurement hedging programs are a tool to reduce price volatility. They serve as insurance that can offset some of the commodity costs in high-price years, though they can result in increased costs in low-price years. The CPUC requires the utilities to purchase physical hedges in the form of long-term interstate pipeline capacity contracts and storage. The utilities also purchase financial hedges, which cover a portion of expected winter gas demand. For example, utilities can purchase the option to buy gas at a certain "strike price" by a given future date, which may be lower than the actual market price at that time.

[41] Bundled rates are paid by core customers who do not use a CTA and include delivery of natural gas and the gas commodity.

[42] The large utilities recover some of their costs from residential core customers through customer charges, either fixed or minimum charges, to partially recover fixed costs associated with service from the distribution system to the meter, including costs related to service lines, regulators, meters, meter reading, and billing.

affected by non-GRC proceedings, such as: 1) advice letter filings dealing with leak abatement and 2) proceedings dealing with biomethane and renewable gas projects; cost of capital; and gas distribution, transmission and storage integrity management programs. Core[43] and noncore gas customers also pay the Public Purpose Program funding requirement via the PPP Surcharge, which is typically revised on the 1st of January.

The decisions of other state and federal agencies are often focused on safety but can also impact rates. The California Geologic Energy Management Division's (CalGEM's) 2018 changes to gas storage regulations increased the cost of maintaining gas storage facilities, and regulations enacted by the federal Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) in 2019 increased the cost of operating and maintaining transmission pipelines. Rates also include the cost of an increasing percentage of the GHG emissions compliance costs resulting from gas consumption, per the California Greenhouse Gas Cap-and-Trade Program implemented by the California Air Resources Board.[44] Cap-and-Trade revenues are also returned directly to residential ratepayers outside of rates through the annual April natural gas California Climate Credit.[45]

Electric and Natural Gas Revenue Collection by Operating Expenses and Capital-Related Expense

To fully understand electric and gas utility costs, it is necessary to understand the difference between two categories of revenue requirement: operating expense and capital-related expense.[46] Operating expense and capital-related expense authorized for recovery during ratesetting proceedings must be converted to the revenue requirement to be collected from ratepayers through rates.

Operating expense is generally passed through to ratepayers each year at cost and is recovered on an immediate dollar-for-dollar basis. Operating expense includes operations and maintenance (O&M) expenses and administrative and general (A&G) expenses. O&M expenses include all labor and non-labor costs for a utility's operation and maintenance of its infrastructure. A&G expenses include costs such as liability insurance and non-infrastructure personnel costs. O&M expense and A&G expense comprise the utility's **operating expense revenue requirement.** These expenses occur every year and as such are collected in full each year.

Capital-related expense and return includes: (1) capital expenditure depreciation expense[47] recovered over a long period of time as the underlying asset depreciates and (2) an authorized profit, consisting of a

[43] CARE customers do not pay the full Gas Public Purpose Program surcharge.

[44] In 2024, Cap-and Trade compliance costs ranged from 16 to 18 cents per therm.

[45] In April 2024, just under $1 billion in Cap-and-Trade auction revenues were returned to customers as direct on-bill automatic natural gas California Climate Credits.

[46] Capital-related expense here includes return on capital.

[47] Net of related tax effect. Depreciation spreads the cost to ratepayers of the capital investment over the assets' useful life.

return on capital invested by the utility in assets, or "return" on the net book value[48] of the utility's assets known as "rate base." Capital expenditure depreciation expense along with return on rate base comprise the utility's **capital-related revenue requirement.**

When net book value increases—which has generally been the case for PG&E, SCE, and SDG&E–rate base increases.[49] Rate base is used as the basis for the **return on rate base revenue requirement.** Increases in rate base over time thus directly result in increases in the return on rate base revenue requirement.[50]

Under this approach, when a utility invests capital in an asset, it cannot recover the full investment in the year it is made. Instead, the utility collects a portion of the investment (depreciation), plus a rate of return (authorized profit), similar to a bank collecting principal and interest on a loan. Because of the multi-year recovery timeframe for capital investments, the related revenue requirement in any given year is a fraction of the total capital-related revenue requirement recovered over the useful life of the asset, with the capital-related revenue requirement included in rates for many years.

Revenue Requirement

Operating expense revenue requirement = O&M expense + A&G expense

Capital-related revenue requirement = Capital expenditure depreciation expense (including related tax effects) + Return on rate base

Return on rate base revenue requirement = Rate base x Rate of return on rate base

As a result, dollar-for-dollar, costs resulting in operating expense revenue requirement have a larger immediate impact on rates than costs resulting in capital-related revenue requirement but have less ratepayer impact in the long run; costs resulting in capital-related revenue requirement have a smaller immediate impact on rates than costs resulting from operating expense revenue requirement but a larger cumulative ratepayer impact in the long run. Figure 1 shows this relationship using a hypothetical cost of $1 billion authorized for recovery in Year 1. The equivalent operating expense revenue requirement is $1 billion and the equivalent capital-related revenue requirement is $1 billion plus a theoretical 10 percent return on the undepreciated capital asset ("return on rate base") over the theoretical capital asset life of 40 years, or a total of $3.05 billion.[51]

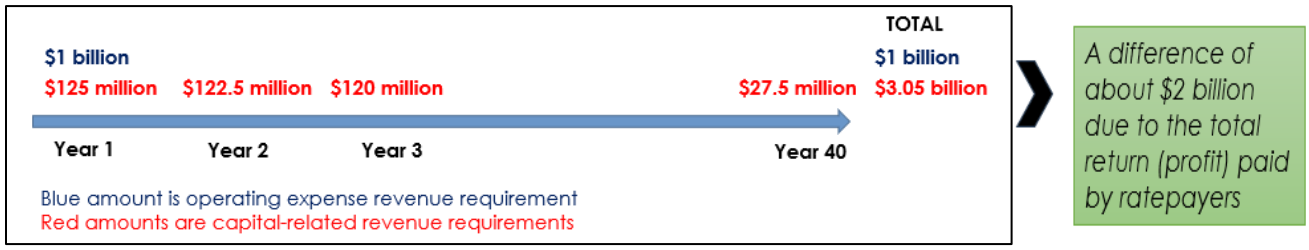
[48] Net of accumulated depreciation. Accumulated depreciation is the cumulative depreciation of an asset up to a single point in its life.

[49] Net book value increases when a utility adds assets and the new book value exceeds accumulated depreciation on the previously-held assets.

[50] Assumes the rate of return on rate base stays constant. The rate of return is subject to change in cost of capital proceedings.

[51] For simplification, asset is assumed to be financed entirely from equity (i.e., no debt), depreciation is on a straight-line basis with no asset salvage value, and there are no tax effects included.

Figure 1: Comparison of Timing of Cost Recovery of $1 Billion
(Operating Expense Revenue Requirement versus Capital-Related Revenue Requirement)



Organization of the 2025 SB 695 Report

The remainder of this report is organized as follows:

- **Chapter III**–A foundational review of historical trends in electric costs and rates with a focus on revenue requirement by functional area of utility operation as well as by operating or capital-related expense classification.
- **Chapter IV**–Additional detailed discussion on special topics related to cost drivers.
- **Chapter V**–An evaluation of electric cost and rate projections with discussion highlighting affordability concerns in low- to moderate-income households.
- **Chapter VI**–Natural gas cost and rate trends.
- **Appendices**–Information provided by the IOUs to fulfill the requirements of Public Utilities Code Section 913.1(b) and reference material.

A digital copy of this report can be found at: https://www.cpuc.ca.gov/about-cpuc/divisions/office-of-governmental-affairs/2025-reports-to-the-legislature.

III. Historical Electric Cost and Rate Trends

The consistent tracking and reporting of historical cost, rate, and bill trends provides a basis for the comparable review of cost attribution and resulting rates and bills. In fact, using historical costs for assessing the reasonableness of future costs is foundational in ratesetting proceedings such as general rate cases. Here, historical cost is tracked on the basis of revenue requirement in rates. Historical rate trends then allow comparison of how an IOU's rates track another metric, inflation, over time. In this chapter, data is anchored to January 1 of each year to maintain consistent year-over-year comparisons.[52]

Revenue Requirement Trends

Simply put, the revenue requirement is what a utility has been authorized to collect from all customers in billing charges in order to provide safe and reliable service. Revenue requirement data is often shown at system-level, which includes the revenue requirement for all customer classes and all bundled and unbundled customers i.e., it is the total revenue requirement that the IOU forecasts it will collect. System-level revenue requirement data can then be grouped to show high-level cost drivers over time.

Trends by Rate Component

Figure 2 presents the combined authorized revenue requirement for PG&E, SCE, and SDG&E at system level, classified by the type of rate component through which the revenue is collected. The type of rate component generally corresponds to a functional area of utility operation, e.g. distribution.[53] While this figure provides an overall summary of revenue requirement that the CPUC has authorized to be in rates as of a given date, January 1, other factors such as the amount of this revenue allocated to a utility's bundled customers–who take both generation and delivery services–and a utility's forecasted sales ultimately determine bundled customer rate trends. Furthermore, the revenue requirements in Figure 2 represent what each IOU has been authorized to collect as of January 1 for the following 12 months, however, these revenue requirements are subject to change during the year as new revenue requirements are authorized (increasing rates) or existing revenue requirements are fully collected (decreasing rates).[54] A breakout for wildfire-related distribution is shown as an overlay (darker red color) on the distribution (red) bar. The black line near the top of the graph shows the revenue requirement after the GHG Revenue (black bar shown as a

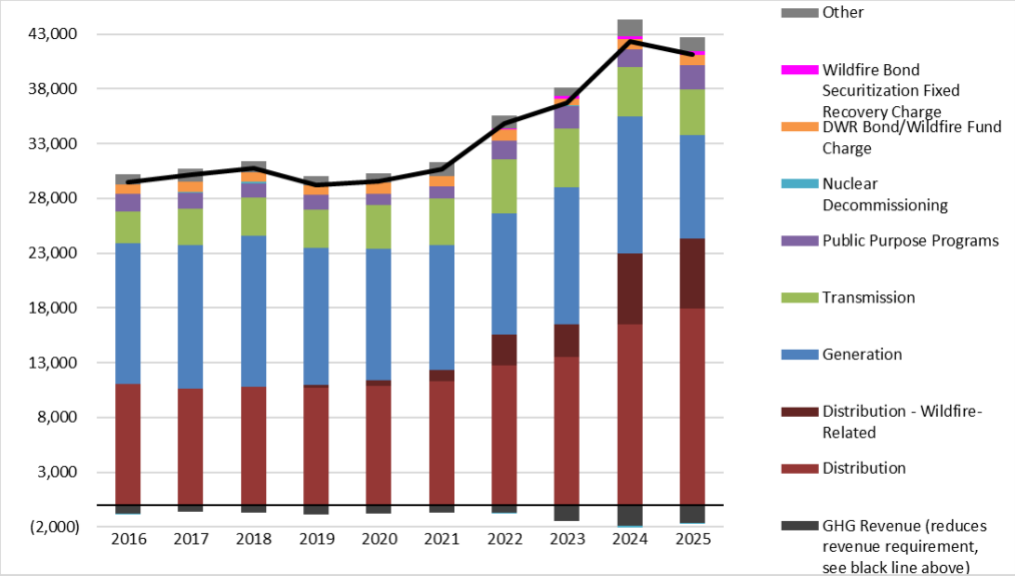
[52] Throughout this chapter, figure or table data is from IOU data responses to SB 695 Report data requests and utility rates implementation advice letters. Total revenue requirement in a utility's rates implementation advice letters also includes the netting effect of the Greenhouse Gas (GHG) Revenue Return, which are funds generated by the Cap-and-Trade Program to be returned as credits to residential customers and small businesses, and for other clean energy purposes. Data in current report may be restated from previous reports. All dollars are nominal i.e., not adjusted for inflation unless otherwise indicated.

[53] Exceptions exist, for example, a program that is funded through the distribution rate component instead of the public purpose program rate component.

[54] Rate changes can occur throughout the year depending on the timing of: 1)final decisions that authorize rate increases to collect additional revenue requirements and 2) removal from revenue requirements amounts that have been fully collected over the authorized period for collection (e.g., the approved amortization period for expenses concludes), resulting in a rate decrease.

credit at the bottom of the graph) is applied.[55] The combined revenue requirement in 2025 is lower than that in 2024 primarily due to PG&E's revenue requirement being lower due to the removal from rates in 2024 of a large revenue requirement corresponding to wildfire-related costs and a generation cost adjustment.[56]

Figure 2: PG&E, SCE, and SDG&E Combined Authorized Electric Revenue Requirement, by Rate Component Category (January 1, $ Millions)



The distribution revenue requirement has grown significantly over time, more than double in 2025 what it was in 2016. The distribution revenue requirement includes costs for power lines, poles, transformers, repair crews and emergency services, as well as certain wildfire mitigation costs related to grid reliability and safety, including liability insurance. Rapid distribution revenue requirement growth starting in 2021 reflects the wildfire-related distribution revenue requirement for vegetation management, infrastructure hardening, and wildfire insurance, among other costs, shown above in dark red[57]

Figure 2 shows the authorized generation revenue requirement (blue bars) which generally consists of short- and long-term contract costs with third-party electricity generators as well as generation plant costs.[58] However, unlike the rest of the revenue requirements in the chart which are for bundled and unbundled

[55] The GHG Revenue credit is represented as a negative amount and reflects the amount available from sale of IOU-allocated allowances to be returned to ratepayers, principally through the California Climate Credit.

[56] *See* "Trends by Bundled System Average Rate" later in this chapter for more information.

[57] Other wildfire-related distribution costs include other wildfire mitigation costs, for example situational awareness costs, as well as other wildfire recovery costs such as catastrophic events costs. *See* Chapter 4, "Wildfire-Related Cost Impacts" for more information.

[58] Short-term (i.e. one year or less) generation revenue requirement generally includes California Independent System Operator (CAISO) wholesale market purchases and other short-term contracts. Long-term (i.e. greater than one year) generation revenue requirement includes, among other things, the Power Charge Indifference Adjustment (PCIA) procurement-related revenue requirement allocated to both bundled and unbundled customers. Bundled customers take generation and delivery services; unbundled customers take delivery service only, with generation service provided by a separate entity, usually a Community Choice Aggregator (CCA) or Direct Access (DA) service provider.

customers, the short-term generation revenue requirement is declining due to customer load departing the incumbent IOU to join Community Choice Aggregators (CCA), who provide separate generation services from the IOU.[59] A small portion of the generation revenue requirement shown in Figure 2 is recovered from CCA and DA customers through the Power Charge Indifference Adjustment (PCIA) rate to cover the legacy cost of generation that was secured while the customers were served by the IOU. However, in recent years, certain PCIA rate components have become more expensive and created a negative PCIA rate, which results in higher generation costs for bundled customers overall and a PCIA credit for departed load customers. As a result of departed load and the PCIA rate, the decline in generation revenue requirement in Figure 2 does not fully reflect the trend of bundled generation rates, which have increased since 2016. For more information, see Chapter 4.

The transmission revenue requirement is set by the Federal Energy Regulatory Commission (FERC) and is the revenue requirement associated with the utilities' assets determined to be part of the interstate transmission system. The Public Purpose Program (PPP) revenue requirement reflects program funding authorized by the CPUC for Electric Program Investment Charge (EPIC), Energy Efficiency programs, Low-Income programs, and other public policy programs.[60] The remainder of the revenue requirements by rate component comprise a smaller portion of the total revenue requirement.[61]

More detailed analysis of select revenue requirements for each IOU is provided in the subsequent chapters of this report.[62]

Trends by Operating Expense and Capital-Related Expense

Distribution and transmission revenue requirements by operating expense and capital-related expense are shown in Figure 3.[63] Operating expense revenue requirement represents short-term pass-through costs and capital-related revenue requirement represents long-term depreciation expense plus a return on capital. Operating expense generally impacts revenue requirement on a one-to-one basis. If the operating expense revenue requirement increases at or below the rate of inflation, the costs that the utility passes directly on to the ratepayer would stay in line with changes in ratepayer buying power, as the rate of inflation can be used

[59] CCAs have grown to serve 38 percent of load in 2025, up from 3 percent in 2016.

[60] PPP revenue requirement does not capture revenue between various customers groups such as the California Alternate Rates for Energy (CARE) subsidy between non-CARE and CARE customers, which results in an additional amount to the PPP rate paid by non-CARE customers. Accordingly, the PPP revenue requirement shown is *after* the forecasted CARE surcharge and discount has flowed from non-CARE to CARE customers.

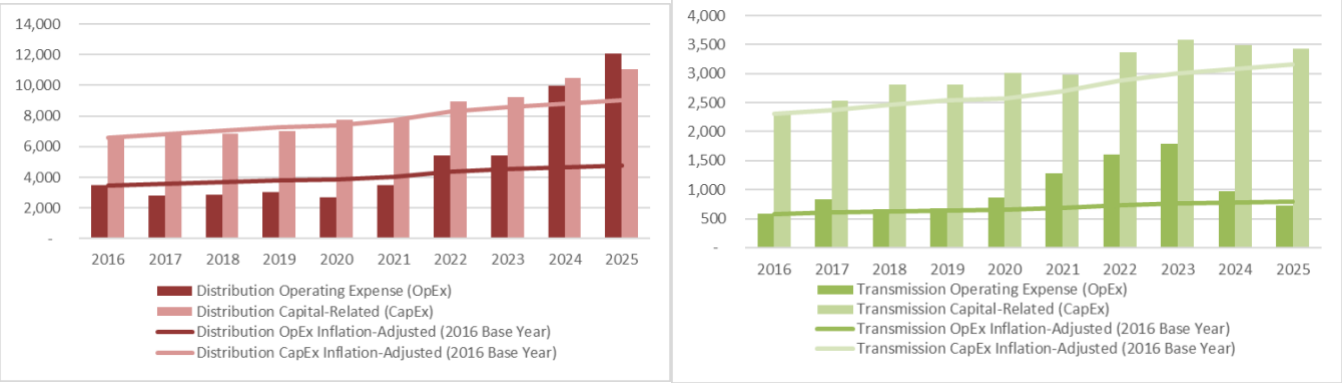
[61] *See* "Electric Costs, Revenue Requirement, and Rates" in Chapter 2 for additional information on these revenue requirements. The Other category may only apply to certain IOUs and not others and includes New System Generation Charge, Competition Transition Charge, Total Rate Adjustment Component, and Energy Crisis Refund Adjustment rate components.

[62] A comprehensive review of utility revenue requirement was not performed, but rather, specific cost categories were selected for further examination. For example, wildfire mitigation and wildfire liability are among the near-term costs that place upward pressure on rates and bills. The Assembly Bill (AB) 67 Reports also provide information about electric revenue requirements drivers for each IOU, using a floating effective date generally corresponding to each IOU's last rate implementation of the report year; *see* AB 67 Reports (Reports to the Legislature, linked by year).

[63] Capital-related expense here includes return on capital. *See* Chapter 2 for more background information on operating expense and capital-related expense revenue requirements.

as an index for changes in affordability. Conversely, if the operating expense revenue requirement increases at a higher rate than inflation, ratepayer buying power is eroded. Capital, on the other hand, does not impact revenue requirement on a one-to-one basis but rater produces pre-determined revenue requirements based on depreciation expense schedules, which may not align with inflation. .[64] A line has been added to each graph in Figure 3 that represents operating expense and capital-related revenue requirements if each had grown at the assumed rate of inflation.[65]

Figure 3: PG&E, SCE, and SDG&E Combined Distribution (Red) and Transmission (Green) Revenue Requirement by Operating Expense and Capital-Related Expense (January 1, $ Millions)



From Figure 3, distribution operating expense revenue requirement (darker bars) comported relatively well with inflation up until 2021, however an upward trend began after then, with 2025 data well exceeding inflation-adjusted data. This observation appears to be coincident with the rise in wildfire-related operating expenses, such as vegetation management and wildfire insurance operating expense, over the period 2021 – 2025. Distribution capital-related revenue requirement (lighter bars) shows an overall increasing rate relative to inflation since 2021. Transmission operating expense revenue requirement (darker bars) exceeded inflation-adjusted data for several years, however, more recent years reflect trends in-line with inflation. Transmission capital-related revenue requirement (lighter bars) shows an overall increasing rate relative to inflation since 2016.

Average Rate Trends

Historical rate trends allow comparison of how an IOU's rates track inflation over time. Inflation is often used as a benchmark to assess electric rate growth because it is based on an assumption that household incomes rise at about the rate of inflation, therefore the affordability of electric service should remain stable

[64] Capital asset depreciation expense is generally determined per depreciation schedules at the time the capital asset is booked.

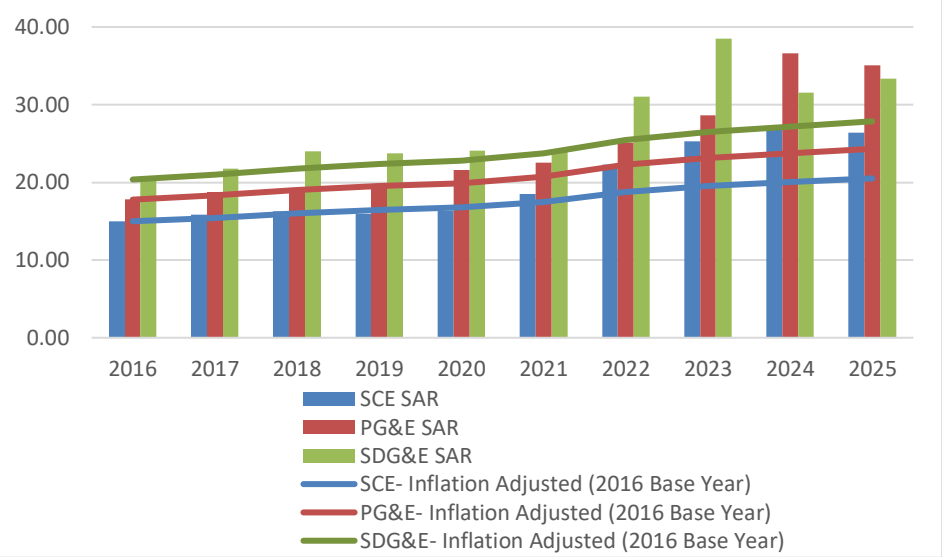
[65] Inflation rate 2016 base year to 2025 is 3.4 percent/year, based on the Consumer Price Index (CPI), California Region, All Items, All Urban Consumers, reported by the California Department of Finance (DOF), available here (CPI Forecast Data published November 2024).

for an average household if electric rates increase with inflation. However, it should be noted that while inflation generally affects the costs underlying the utility's revenue requirement, rates and bills are impacted by other factors, such as wholesale natural gas prices, high interest rates, and continuing supply chain challenges in the aftermath of the Covid-19 pandemic, all of which have driven the escalation in rates well above inflation.

Trends by Bundled System Average Rate

California energy utility customers continue to face financial pressure from rate increases. Starting in 2021, bundled system[66] average rate (SAR) increases began to outpace inflation for the three large electric IOUs, with significant increases in 2022 and 2023, as shown in Figure 4. In 2025, all three IOUs' bundled SARs remain substantially higher than the assumed rate of inflation since 2016.

Figure 4: PG&E, SCE, and SDG&E January 1 Bundled System Average Rate, Nominal and Inflation-Adjusted Comparison (cents/kWh)



[66] Bundled IOU customers take all services–generation, transmission, and distribution services–from the IOU; System-level includes all customer classes.

PG&E's bundled SAR decrease in 2025 from 2024 reflects in part the following:

- The removal from rates in 2024 of a large revenue requirement corresponding to wildfire-related costs and a generation cost adjustment.[67]

SCE's bundled SAR decrease in 2025 from 2024 reflects in part the following:

- The removal from rates in 2024 of a large revenue requirement corresponding to wildfire-related costs and generation cost adjustments.[68]
- A lower-than-expected SAR in 2025 due to its GRC not implementing on January 1, 2025. This deflates the 2025 bar in the chart relative to where it would have been if the GRC had implemented on January 1, 2025.

SDG&E's bundled SAR decrease in 2024 and 2025 from 2023 reflects in part the following:

- A lower-than-expected SAR in 2024 and 2025 due to its GRC not implementing on January 1, 2024 or January 1, 2025; this deflates the 2024 and 2025 bars in the graph relative to where they would have been if the GRC had implemented on January 1, 2024. SDG&E requested an extension of time on December 9, 2024 to implement electric rate changes on February 1, 2025 rather than January 1, 2025. The CPUC approved SDG&E's GRC on December 19, 2024.[69]

The bundled system average rate in Figure 4 is broken down by customer class e.g., residential, small commercial, etc. for each IOU in Figures 5 – 7.[70] Each class rate shows the same upward trend as the system average rate over this period, with residential, small commercial, and medium commercial customers generally having higher average rates than the system average, and the large industrial and agricultural customers having lower average rates, with the exception of PG&E agricultural customers who have higher average rates than system starting in 2019.[71]

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[67] While rate increases throughout the year were offset by other reductions in costs which resulted in a net rate decrease, the largest decreases are detailed by PG&E in their July 2024 Electric Rate Advisory as the removal from rates of recorded costs related to wildfire mitigation activities in PG&E's 2022 Wildfire Mitigation and Catastrophic Events (WMCE) application and removal from rates of certain costs related to purchasing electricity as part of PG&E's 2025 Energy Resource Recovery Account (ERRA) Forecast application.

[68] *See* SCE AL 5307-E, "Items Removed From Rates," specifically "2023 Energy Resource Recovery Account (ERRA) Trigger" and "Wildfire Expense Memorandum Account (WEMA) 2" and SCE AL 5379-E, "2024 ERRA Trigger."

[69] D.24-12-074.

[70] PG&E customer class rate schedules Res = non-CARE and CARE; Small (e.g., B-1); Medium = B-10 & E-19; Large, also known as Industrial = E-20; Ag = AG; SCE customer class rate schedules Res = non-CARE and CARE; Small = TOU-GS-1; Medium = TOU-GS-2 & TOU-GS-3; Large, also known as Industrial = TOU-8-S/P/T & TOU-8-S-S/P/T; Ag = TOU-PA-2 & TOU-PA-3; SDG&E customer class rate schedules are not associated with any specific rate schedule. SDG&E has a combined medium/large commercial & industrial customer class.

[71] This effect for PG&E agricultural customers is driven mostly by the changes in the billing determinants that reflect changes in electric usage patterns for the Agricultural class.

Figure 5: PG&E Bundled System Average Rate By Class, Nominal Rates in Effect January 1 (¢/kWh)

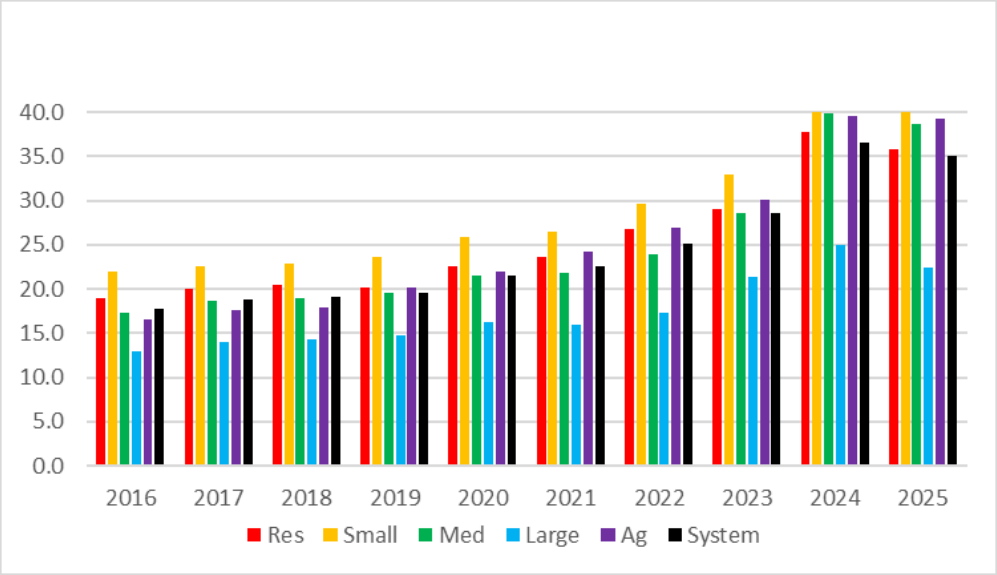


Figure 6: SCE Bundled System Average Rate By Class, Nominal Rates in Effect January 1 (¢/kWh)

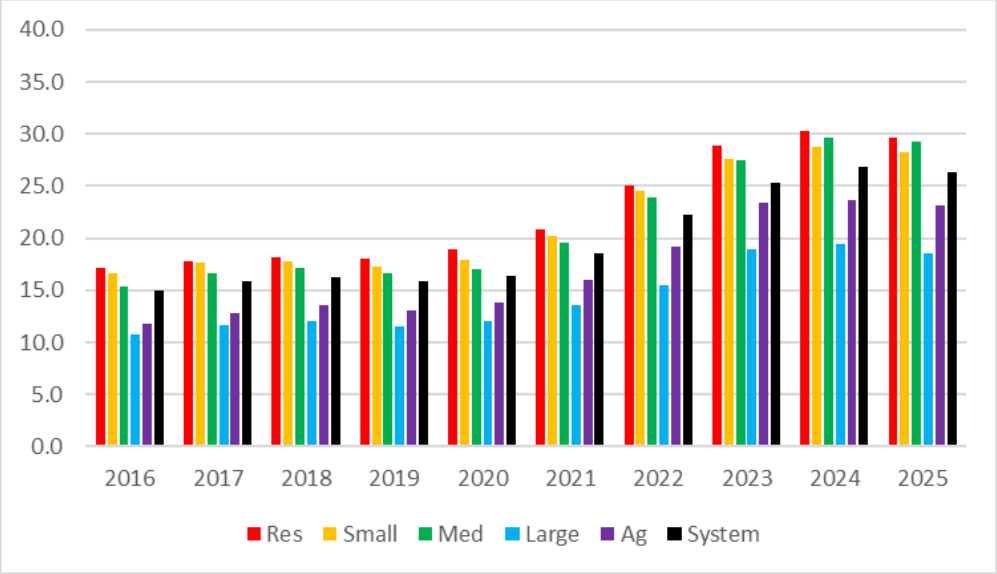
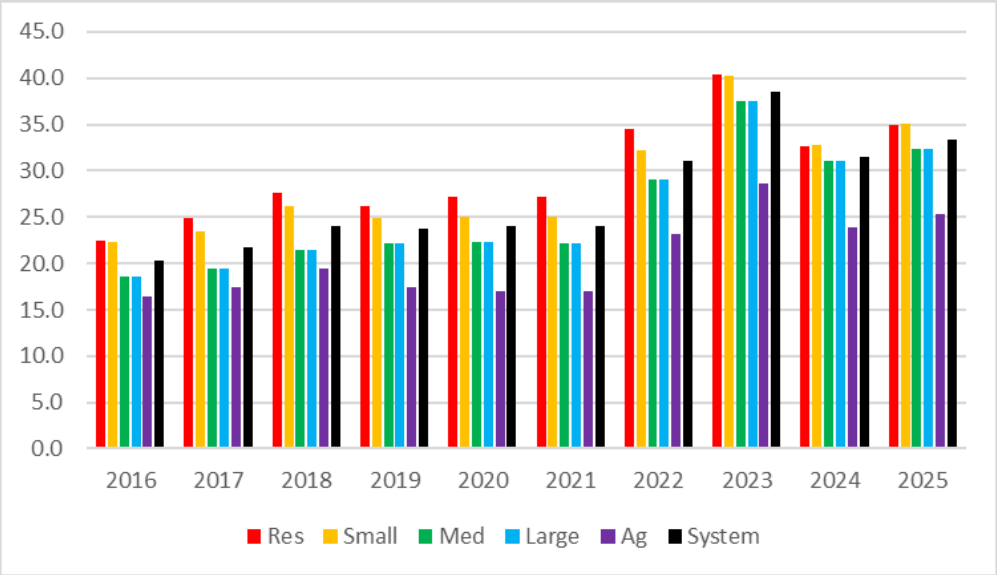


Figure 7: SDG&E Bundled System Average Rate By Class, Nominal Rates in Effect January 1 (¢/kWh)



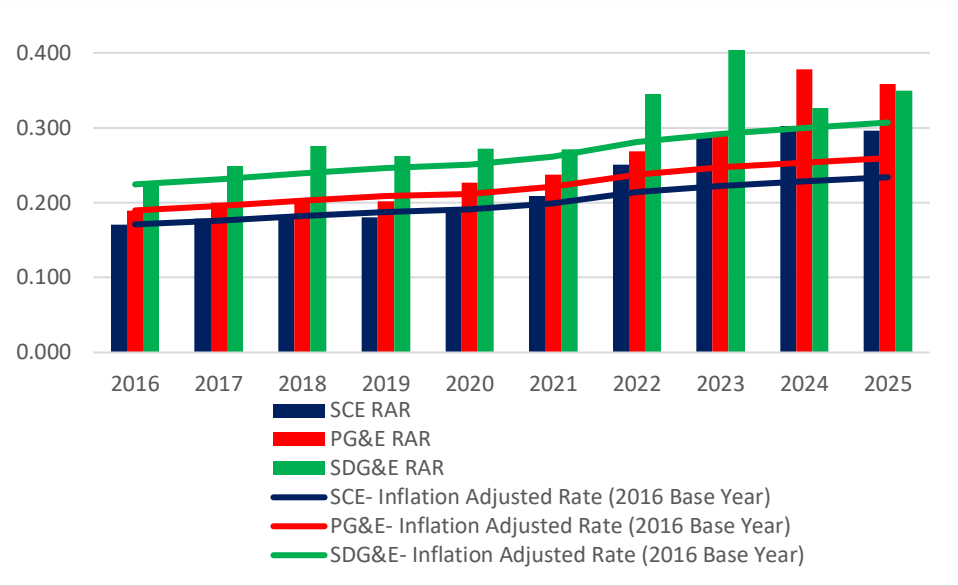
Trends by Bundled Residential Average Rate

Since 2016, bundled residential average rates (RAR) have increased at an average annual rate greater than the assumed rate of inflation: about 10 percent for PG&E, 8 percent for SCE, and 6 percent for SDG&E as shown in Figure 8.[72] The bundled RAR trends reflect the same trends as for bundled SAR, with the height of each bar showing higher rates for RAR than for SAR, in accordance with residential customers having higher rates than system rates. This is because residential customers are "small" customers compared to "large" non-residential customers, and service to small customers requires more capital cost per kWh served and is disproportionately higher during peak periods.[73]

[72] Average annual percent changes to utility rates throughout this report are based on a simple, smoothing calculation of: (end of period value – beginning of period value)/number of periods where 'periods' is defined as a range of years.

[73] A peak period is a time-of-use period when energy costs are highest.

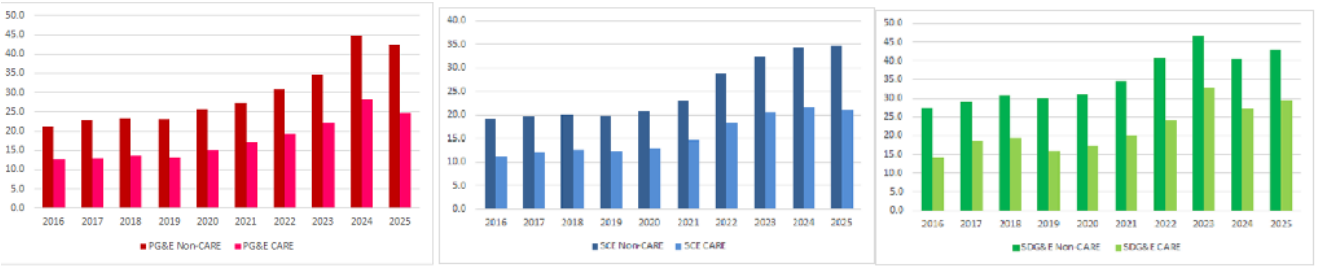
Figure 8: PG&E, SCE, and SDG&E January 1 Bundled Residential Average Rate, Nominal and Inflation-Adjusted Comparison ($/kWh)



Bundled Residential Average Rate by Non-CARE and CARE Rates

The bundled RAR shown in Figure 8 can be further subdivided into bundled non-CARE and CARE rates as shown in Figure 9. The CARE program is a low-income energy rate assistance program that provides a 30 percent – 35 percent discount on electric bills to qualifying low-income households with incomes at or below 200 percent of the Federal Poverty Guideline.[74] CARE is funded by a surcharge paid by all customers except for CARE customers, resulting in separate non-CARE and CARE residential rates.

Figure 9: PG&E, SCE, and SDG&E January 1 Bundled Residential Average Non-CARE and CARE Rates (cents/kWh)



[74] A 20 percent discount is also applied for eligible gas customers. In addition to the CARE program, the Family Electric Rate Assistance (FERA) program provides families of three or more whose household income slightly exceeds the CARE allowances with an 18 percent discount on their electricity bill. Only the CARE program is discussed here.

Non-CARE rates have reached about $0.45/kWh for PG&E and SDG&E, and about $0.35/kWh for SCE in recent years. Non-CARE rates are higher because they include (1) the surcharge that funds CARE program discounts and administrative expense and (2) payments for certain non-bypassable charges (NBC) that CARE customers are exempt from paying and are therefore are paid by non-CARE customers.[75] Table 2 shows the estimated amount of a non-CARE customer's bill that goes towards paying the CARE surcharge and the CARE customer rate exemptions for certain NBCs.[76]

Table 2: PG&E, SCE, and SDG&E Portion of Non-CARE Customer Average Monthly Electric Bill to Fund CARE Program Surcharge and CARE Customer Rate Exemptions (Year-End 2024)

	Total Monthly Bill	CARE Program Surcharge and Administrative Expense	CARE Customer Rate Exemptions Funded by Non-CARE Customers	CARE Program Surcharge & CARE Customer Rate Exemptions Portion (%)
PG&E	$212	$8	$2	5%
SCE	$159	$5	$4	6%
SDG&E	$153	$6	$2	5%

Rate and Bill Comparisons with National Trends

California's electric utility rates are trending higher in national comparisons. Historically, the bundled Residential Average Rates (RAR) of the California IOUs have been higher than those of most United States IOUs. Table 3 shows ranking data based on U.S. Energy Information Administration (U.S. EIA) bundled RAR for PG&E, SCE, and SDG&E from 2019 to 2023.[77] The year 2023 is the most recent year for which national-level annual data is available. This data ranks approximately 200 total IOUs nationally from highest rates (#1 ranking) to lowest rates (#200 ranking). For example, in 2023, SDG&E's bundled RAR ranked 2nd highest.[78]

U.S. EIA data shows that from 2019 to 2023, California IOU bundled residential customer bills have been trending upward relative to the bills of approximately 200 total IOUs nationally. For example, in 2019, PG&E's bundled residential average monthly bill ranked 70th highest out of about 200 IOUs, while in 2023,

[75] Rate exemptions include the Wildfire Fund Charge and the Wildfire Hardening Fixed Recovery Charge resulting from certain securitizations; only PG&E and SCE have these securitizations. Non-CARE residential and all non-residential customers fund the CARE surcharge and CARE customer rate exemptions.

[76] Non-CARE residential and all non-residential customers fund the CARE surcharge and CARE customer rate exemptions; only non-CARE residential bill portions shown here. Bill figures are rounded. Typical non-CARE customer using 500 kWh (PG&E climate zone X, SCE climate zone 9) and 400 kWh (SDG&E Inland climate zone). Bills are for illustrative purposes only.

[77] *See* https://www.eia.gov/electricity/sales_revenue_price/, Table 6.

[78] An IOU located in Hawaii ranked highest.

it ranked 23rd highest. SCE and SDG&E's bundled residential average monthly bills show similar movement in bill ranking trends since 2019, as shown in Table 3.

Table 3: U.S. IOU Ranking of PG&E, SCE, and SDG&E (Out of Approximately 200 IOUs) Highest Bundled Residential Average Rates and Monthly Bills (U.S. EIA)

	Bundled Residential Average Rate (cents/kWh)					Bundled Residential Average Monthly Bill ($)				
	2019	**2020**	**2021**	**2022**	**2023**	**2019**	**2020**	**2021**	**2022**	**2023**
PG&E	24	13	9	7	10	70	25	17	18	23
SCE	42	21	17	17	14	142	85	70	65	46
SDG&E	17	9	6	5	2	122	87	88	43	26

Table 4 shows the corresponding U.S. EIA rate and monthly bill amounts for the large California IOUs. U.S. EIA rate data is on a simple volumetric basis of revenues divided by sales, without regard to rate design and bill data is the simple volumetric rate multiplied by average monthly usage data.[79]

Table 4: PG&E, SCE, SDG&E Bundled Residential Average Rate and Monthly Bill (U.S. EIA)

	Bundled Residential Average Rate (cents/kWh)					Bundled Residential Average Monthly Bill ($)				
	2019	**2020**	**2021**	**2022**	**2023**	**2019**	**2020**	**2021**	**2022**	**2023**
PG&E	22.4	23.7	25.9	31.0	34.0	$118	$139	$150	$169	$166
SCE	16.2	18.2	21.3	24.6	32.3	$93	$109	$121	$138	$153
SDG&E	25.8	25.5	30.7	37.9	45.4	$99	$107	$112	$148	$165

[79] Bill amounts are hypothetical at class level without distinction between customers who receive a low-income program bill discount and those who do not. U.S. EIA data for 2023 shows average monthly usage figures: PG&E 489 kWh; SCE 473 kWh; SDG&E 363 kWh.

IV. Special Topics

As in the reports from the last several years, the 2025 report sharpens its focus on wildfire-related cost drivers as well Net Energy Metering (NEM) and Net Billing Tariff (NBT) program cost trends. For this year's edition, additional content is provided regarding the bundled residential generation rate. Recent actions to limit cost and rate increases taken by the CPUC[80] and the IOUs (excerpted from each IOU's Report to Limit Cost and Rate Increases)[81]are included where applicable.[82]

Wildfire-Related Cost Impacts

Climate change, primarily caused by the burning of fossil fuels, is increasing the frequency and severity of wildfires in California.[83] Catastrophic wildfires, in part ignited and exacerbated by heat and drought that make vegetation more flammable, threaten distribution and transmission infrastructure. Wildfire-related legislation enacted in 2018 and 2019 forms the backdrop for the historical wildfire-related costs presented here.

Legislative and Regulatory Background

SB 901 (Dodd, 2018) and AB 1054 (Holden, 2019) require electric utilities to prepare and submit wildfire mitigation plans (WMP) to the Office of Energy Infrastructure Safety (Energy Safety) which describe the level of wildfire risk in their service territories and how they intend to address those risks. The WMPs cover a three-year period with new comprehensive plans to be filed at least once every three years and annual updates to the plans in between.[84] The current 2026 - 2028 cycle is the third three-year cycle for which electrical corporations have been required to submit WMPs.[85]

SB 901 and AB 1054 require the CPUC to allow each IOU to open a memorandum account to track spending to implement its WMP.[86] While the majority of WMP-related *forecast* costs are now included in an

[80] Actions taken during 2023 – 2024.

[81] Full IOU reports available here; *See* "2025 Electric and Gas Costs Utility Reports" bullet point under the "Reports and White Papers" section of the webpage. Inclusion of IOU report elements in this report does not imply CPUC endorsement.

[82] Throughout this chapter, figure or table data is from IOU data responses to SB 695 Report data requests. Data in current report may be restated from previous reports. Previous year-end data is used in this chapter rather than January 1 data of previous chapters to capture a full year of data.

[83] *See* California Air Resources Board (CARB), "Wildfires and Climate Change": https://ww2.arb.ca.gov/wildfires-climate-change.

[84] Pursuant to Public Utilities Code section 8386(b), electrical corporations must annually prepare and submit a WMP to the Office of Energy Infrastructure Safety (Energy Safety) for review and approval. The plans must cover at least a three-year period and must satisfy requirements set forth by Energy Safety. At its discretion, Energy Safety may allow the annual submissions to be updates to the last approved Base WMP, provided that each electrical corporation submits a Base WMP at least once every three years.

[85] *See* each IOU's 2026 – 2028 Base WMP.

[86] The first GRC each IOU filed with forecasted WMP costs were SCE's 2021 GRC, PG&E's 2023 GRC, and SDG&E's 2024 GRC, however, all three IOUs were recording wildfire-mitigation costs in memorandum accounts to be reviewed for cost recovery at a later date prior to filing these GRCs.

IOU's General Rate Case (GRC),[87] IOUs may seek *after-the-fact* recovery of amounts recorded in WMP-related memorandum accounts for incremental spending incurred to implement an approved WMP.[88] Balancing accounts, which are used to record costs and revenues that fluctuate over time, are also used to record certain costs for future recovery that exceed authorized forecasted costs.[89] The IOUs also recover certain wildfire-related costs that are external to the activities described in the WMP, including wildfire insurance premium costs to cover claims paid as a result of property losses and costs related to recovering from catastrophic events.[90]

Unique to California under the Inverse Condemnation Doctrine, the IOUs play a role similar to insurance companies for private property damage from wildfires ignited by utility equipment without showing of fault and without policy limits. Partly as a consequence of the Inverse Condemnation Doctrine, AB 1054 created a $21 billion Wildfire Fund for excess liabilities resulting from utility-caused wildfires, funded equally by ratepayers and utility shareholders.[91] A non-bypassable charge (NBC) is collected from non-exempt ratepayers to support the fund, with CARE and Medical Baseline customers exempt from paying the NBC.

SB 884 (2022, McGuire) focuses on increasing electric reliability through reducing de-energization events as part of reducing wildfire risk and allows PG&E, SCE, and SDG&E to voluntarily submit a 10-year distribution system undergrounding plan to Energy Safety. If Energy Safety approves the electrical corporation's undergrounding plan, the plan is submitted to the CPUC with an application requesting cost recovery.[92] Energy Safety issued its 10-Year Electrical Undergrounding Plan (EUP) Guidelines on February 20, 2025, and no EUP applications have been filed yet with the CPUC.

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[87] PG&E's 2027 GRC wase filed in May 2025 and SDG&E's 2028 GRC is expected to be filed in May 2026. SCE's 2025 GRC, covering the period 2025 – 2028, is currently pending. All three IOUs may be recording Energy Safety-approved WMP costs over currently authorized GRC costs in memorandum accounts.

[88] This cost recovery may be done through the GRC process or through a separate application. A utility's business decision about how and when to apply for cost recovery, along with the regulatory process, may add several years from the time costs are incurred until the time they are authorized for recovery.

[89] Wildfire-related balancing accounts include Vegetation Management Balancing Accounts (VMBA) and Wildfire Mitigation Balancing Accounts (WMBA).

[90] Wildfire insurance costs that are incremental to the insurance costs authorized in the GRCs may be tracked for recovery through the Wildfire Expense Memorandum Account (WEMA) for PG&E and SCE, and the Liability Insurance Premiums Balancing Account (LIPBA) for SDG&E. Eligible costs to respond to catastrophic events, including wildfires are tracked for recovery through Catastrophic Event Memorandum Accounts (CEMA). Permissible CEMA expenses include restoring utility services to customers; repairing, replacing, or restoring damaged utility facilities; and complying with government agency orders resulting from declared disasters.

[91] Utilities must meet certain conditions to participate in the fund.

[92] *See* Resolution SPD-15 for more information on SB 884 program guidelines.

Authorized Costs

Since 2019 and as of fourth quarter 2024, the IOUs have been authorized to collect approximately $27 billion of wildfire mitigation costs to support the state's wildfire prevention efforts and approximately $14 billion for wildfire insurance premiums and catastrophic events costs ("wildfire liability").[93] Together, wildfire mitigation and wildfire liability costs are referred to as "wildfire-related" costs. Total wildfire-related costs authorized between 2019 and 2024 are approximately $40 billion as shown in Table 5.[94] Authorized costs in Table 5 will be larger than the corresponding revenue requirement that goes into rates each year as large capital-related costs, when converted to revenue requirement, will go into rates gradually over a long period of time.[95] Costs correspond to the last rate implementation of each year 2019 – 2024 and include wildfire-related costs from GRC implementations as well as implementations of cost recovery authorized outside the GRC process such as WMP-related memorandum account costs.

[93]Includes CPUC and FERC authorizations, except for PG&E which declined to provide FERC-related wildfire insurance and catastrophic events data and SDG&E which states it is not able to provide FERC-related wildfire mitigation data because WMP is a CPUC-jurisdictional balanced program. Additional costs may have been incurred during the 2019 – 2024 period but may not have yet been authorized for collection; cost figures exclude certain wildfire liabilities that were pending cost recovery authorization at year-end 2024 such as: 1) costs SCE incurred due to the 2017 Thomas Fire and 2018 Montecito debris flow approved for recovery on January 30, 2025, which SCE intends to seek to recover through securitization (*see* D.25-01-042);and 2) costs related to SDG&E's 2024 GRC which were approved for recovery in late 2024 but did not implement until 2025 (*see* D.24-12-074).

[94] Prior to 2023, PG&E insurance amount is total insurance, as general liability and wildfire liability insurance is not split in company records. PG&E indicates excess liability represents the primary component of general liability, and wildfire excess liability cost is greater than non-wildfire. Starting in 2021, SCE insurance amounts are wildfire only. A small portion of SDG&E insurance balance is unrelated to wildfire. Catastrophic events costs are substantially related to fire-related events, however, costs for other non-wildfire related events such as severe storms and wind events are also included.

[95] Because the costs in Table 5 are larger than the corresponding revenue requirement in Table 6 due to the conversion of capital-related costs to revenue requirement over time, the data in Table 5 should not be used as an estimate of the amount that has gone into rates. That estimate is better represented by revenue requirement in Table 6. *See* Chapter 2 for more information about how capital-related costs are converted to revenue requirement. Year-end cost data that goes into rates may not represent costs over the full course of the year. For example, costs implemented in rates after January 1 will not reflect a full year of being in rates.

Table 5: Total Wildfire-Related Authorized Costs
(2019 – 2024, Year-End, $ billions)

Utility	2019 – 2024 Total Wildfire-Related Authorized Costs (sum of columns to right)	2019 – 2024 Total Wildfire Mitigation Authorized Costs	2019 – 2024 Total Wildfire Insurance / Catastrophic Events Authorized Costs
PG&E	$22.7	$15.9	$6.8
SCE	$14.9	$9.4	$5.5
SDG&E	$2.6	$1.3	$1.3
Total	$40.2	$26.6	$13.6

Revenue Requirement in Rates

Table 6 shows the authorized costs in Table 5 that were converted to revenue requirement and went into rates over the period 2019 – 2024. Total wildfire-related revenue requirement between 2019 and 2024 is approximately $27 billion.[96] The revenue requirements amounts are smaller than the corresponding authorized costs as large capital-related costs, when converted to revenue requirement, will go into rates gradually over a long period of time.[97] While the annual depreciation amount in the revenue requirement corresponding to the capital asset is smaller than the cash outlay for the asset, capital-related costs ultimately result in greater expense to ratepayers due to the inclusion of the rate of return on the capital asset as part of capital-related revenue requirement. For more information, including an example that illustrates this concept, see Chapter 2.

[96] The data included in Table 6 shows that over the 6 year period 2019 – 2024, approximately $4.4 billion per year on average of wildfire-related revenue requirement was in rates at year-end. Year-end cost data that goes into rates may not represent costs over the full course of the year. For example, costs implemented in rates after January 1 will not reflect a full year of being in rates.

[97] Figure 1 in Chapter 2 shows on a simplified basis a comparison of the timing of a $1 billion cost recovery: at the end of a capital asset's life, there is an additional $2 billion added to the total cost recovery of the capital asset compared to operating expense cost recovery. Year-end revenue requirement data may not represent revenue requirement over the full course of the year. For example, revenue requirement implemented after January 1 will not reflect a full year of being in rates.

Table 6: Total Wildfire-Related Revenue Requirement
(2019 – 2024, Year-End, $ billions)

Utility	2019 – 2024 Total Wildfire-Related Revenue Requirement (sum of columns to right)	2019 – 2024 Total Wildfire Mitigation Revenue Requirement	2019 – 2024 Total Wildfire Insurance / Catastrophic Events Revenue Requirement
PG&E	$15.3	$9.6	$5.7
SCE	$9.4	$3.9	$5.5
SDG&E	$2.1	$0.7	$1.4
Total	$26.8	$14.2	$12.6

Tables 7-9, below, show the year-by-year incremental revenue requirement reflected in 2019 - 2024 rates at year-end corresponding to each IOU's wildfire-related revenue requirement by CPUC and FERC jurisdiction, broken out by operating expense (OpEx) revenue requirement and capital expense (CapEx) revenue requirement.[98] CPUC-jurisdictional costs for both wildfire mitigation and wildfire liability are generally recovered through the distribution rate component; however, starting in the fourth quarter of 2020, all IOUs recovered Wildfire Fund costs through a dedicated, non-bypassable wildfire fund rate component generally known as the Wildfire Fund Non-Bypassable Charge (NBC).[99] Similarly, starting in 2021, PG&E and SCE began recovering securitized wildfire mitigation costs through a dedicated, non-bypassable securitization rate component generally known as the Wildfire Hardening Fixed Recovery Charge (FRC) NBC.[100] The data underlying Tables 7 - 9 is also aggregated in Figure 10, below, at the OpEx and CapEx level.

[98] CapEx here includes return on capital. *See* Chapter 2 for more background information on operating expense and capital-related expense revenue requirements.

[99] The actual name varies by IOU; *see* AB 1054 discussion earlier in this section for more information. Residential customers enrolled in the California Alternate Rates for Energy CARE) program are exempt from paying the Wildfire Fund NBC.

[100] The actual name varies by IOU; *see* AB 1054 discussion earlier in this section for more information.

Table 7: PG&E Wildfire-Related Revenue Requirement by Distribution, Transmission, and Non-Bypassable Charge Rate Components, by Operating Expense and Capital Expense (Year-End, $ millions)

		Wildfire-Related Distribution	Wildfire Fund NBC	Wildfire Hardening FRC NBC	Wildfire-Related Transmission	Subtotal Wildfire-Related Rev Req (See Figure 10)	Total Wildfire-Related Rev Req	Total Rev Req	% Wildfire-Related Rev Req to Total Rev Req
2019	OpEx	$68.9	-	-	-	$68.9	**$73.6**	**$13,561.6**	**0.5%**
	CapEx	$4.7	-	-	-	$4.7			
2020	OpEx	$275.5	$427.3	-	$16.0	$718.8	**$743.2**	**$14,145.9**	**5.3%**
	CapEx	$22.9	-	-	$1.5	$24.4			
2021	OpEx	$1,985.3	$403.4	-	$138.4	$2,527.1	**$2,610.2**	**$14,381.7**	**18.1%**
	CapEx	-$14.6	-	$82.3	$15.4	$83.1			
2022	OpEx	$2,223.2	$457.0	-	$381.9	$3,062.1	**$3,263.4**	**$15,105.9**	**21.6%**
	CapEx	$45.9	-	$81.7	$73.7	$201.3			
2023	OpEx	$1,970.4	$378.3	-	$414.4	$2,763.1	**$3,211.0**	**$17,759.2**	**18.1%**
	CapEx	$142.6	-	$148.8	$156.5	$447.9			
2024	OpEx	$4,198.2	$393.1	-	$263.0	$4,854.3	**$5,404.4**	**$20,341.2**	**26.6%**
	CapEx	$199.8	-	$296.3	$54.0	$550.1			

Table 8: SCE Wildfire-Related Revenue Requirement by Distribution, Transmission, and Non-Bypassable Charge Rate Components, by Operating Expense and Capital Expense (Year-End, $ millions)

		Wildfire-Related Distribution	Wildfire Fund NBC	Wildfire Hardening FRC NBC	Wildfire-Related Transmission	Subtotal Wildfire-Related Rev Req (See Figure 10)	Total Wildfire-Related Rev Req	Total Rev Req	% Wildfire-Related Rev Req to Total Rev Req
2019	OpEx	$287.5	-	-	$1.0	$288.5	**$288.5**	**$11,120.6**	**2.6%**
	CapEx	-	-	-	-	-			
2020	OpEx	$409.6	$428.1	-	$168.1	$1,005.8	**$1,006.4**	**$12,665.3**	**7.9%**
	CapEx	-	-	-	$0.6	$0.6			
2021	OpEx	$1,047.2	$393.1	-	$57.2	$1,497.5	**$1,547.6**	**$14,294.4**	**10.8%**
	CapEx	$28.4	-	$19.3	$2.4	$50.1			
2022	OpEx	$888.7	$447.0	-	$146.8	$1,482.5	**$1,634.6**	**$15,170.3**	**10.8%**
	CapEx	$101.0	-	$51.0	$0.1	$152.1			
2023	OpEx	$1,170.3	$402.3	$55.3	$119.1	$1,747.0	**$1,995.8**	**$17,429.14**	**11.5%**
	CapEx	$197.7	-	$51.0	$0.1	$248.8			
2024	OpEx	$1,719.8	$408.9	$55.3	$127.5	$2,311.5	**$2,907.3**	**$17,449.9**	**16.7%**
	CapEx	$544.7	-	$51.0	$0.1	$595.8			

Table 9: SDG&E Wildfire-Related Revenue Requirement by Distribution, Transmission, and Non-Bypassable Charge Rate Components, by Operating Expense and Capital Expense (Year-End, $ millions)

		Wildfire-Related Distribution	Wildfire Fund NBC	Wildfire Hardening FRC NBC	Wildfire-Related Transmission	Subtotal Wildfire-Related Rev Req (See Figure 10)	Total Wildfire-Related Rev Req	Total Rev Req	% Wildfire-Related Rev Req to Total Rev Req
2019	OpEx	$99.7	-	-	$14.7	$114.4	**$126.2**	**$4,211.7**	**3.0%**
	CapEx	$11.8	-	-	-	11.8			
2020	OpEx	$104.2	$22.6	-	$18.3	$145.1	**$182.5**	**$4,142.0**	**4.4%**
	CapEx	$37.4	-	-	-	$37.4			
2021	OpEx	$162.9	$90.2	-	$23.6	$276.7	**$321.4**	**$4,334.8**	**7.4%**
	CapEx	$44.7	-	-	-	$44.7			
2022	OpEx	$212.0	$84.7	-	$30.0	$326.7	**$376.1**	**$4,215.5**	**8.9%**
	CapEx	$49.4	-	-	-	$49.4			
2023	OpEx	$204.5	$75.5	-	$38.7	$318.7	**$371.8**	**$4,376.5**	**8.5%**
	CapEx	$53.1	-	-	-	$53.1			
2024	OpEx	$427.9	$84.7	-	$41.6	$554.2	**$684.7**	**$4,135.5**	**16.6%**
	CapEx	$130.5	-	-	-	$130.5			

Revenue requirements in the first column of Tables 7 – 9, Wildfire-Related Distribution, include wildfire-related revenue requirements from GRC implementations as well as implementations of cost recovery authorized outside the GRC process such as WMP-related memorandum account revenue requirements. Table 10 shows the Wildfire-Related Distribution data in Tables 7 - 9 by authorization on a forecasted basis through the GRC process and on a historical, recorded basis such as for memorandum account cost recovery. Columns have been added to indicate applications for which cost recovery has not been implemented at year-end 2024 due to: (1) authorization in 2024 but not implemented at year-end 2024; (2) authorization pending for amount above that previously authorized for interim rate recovery (IRR);[101] or (3) authorization was pending at year-end 2024.

[101] IRR is granted pending a final decision on what permanent cost increase, if any, is reasonable and is subject to refund.

Table 10: Wildfire-Related Distribution Revenue Requirement In Rates and For Future Implementation, by Basis of Cost Recovery
(2019 – 2024, Year-End, $ billions)

IOU	Wildfire-Related Distribution Revenue Requirement In Rates Year-End 2019 – 2024			Applications at Year-End 2024 For Future Implementation		
	Forecasted Basis (GRC Process)	Historical Basis (Recorded)	Total	Proceeding	Amount Requested or to be Implemented	Basis and Reason*
PG&E	$4.3	$6.8	$11.1	2021 WMCE A.21-09-008	$0.4	Historical – 1) & 2)
				2022 WMCE A.22-12-009	$0.2	Historical – 2)
				Wildfire Gas & Safety Costs A.23-06-008	$0.2	Historical – 2)
				2023 WMCE A.23-12-001	$1.0	Historical – 2)
				2024 WMCE A.24-11-009	$0.2	Historical – 3)
SCE	$3.3	$3.1	$6.4	2025 GRC WM A.23-05-010	$6.3102	Forecasted – 3)
				Thomas Fire & Montecito Debris Flow WEMA & CEMA A.23-08-013	$1.7103	Historical – 3)
				2022 WM/VM A.23-10-001	$0.2	Historical – 2)
				WMCE A.24-04-005	$0.3	Historical – 3)
				Woolsey Fire WEMA & CEMA A.24-10-002	$5.5104	Historical – 3)
SDG&E	$0.9	$0.6	$1.2	2024 GRC WM A.22-05-016	Not Available105	Forecasted – 1)
				WMPBA Track 2 in 2024 GRC A.22-05-026	$0.1	Historical – 1)

[102] Total amount requested, not incremental over authorized amount, over 2025 – 2028 GRC cycle.

[103] Authorized in early 2025. Recovers 60 percent of the amounts recorded in WEMA through May 31, 2024 (about $1.627 billion of the approximately $2.712 billion total), and 85 percent of the amounts recorded in CEMA (about $55.228 million of the $64.974 million), for a permanent disallowance of about $1.094 billion.

[104] Approximately $5.4 billion in claims costs paid and legal costs incurred as of August 2024 to resolve third-party claims arising from the 2018 Woolsey Fire and associated financing costs (the WEMA costs) and approximately $84 million in restoration-related costs (the CEMA costs).

[105] Breakout of the wildfire mitigation (WM) portion authorized in SDG&E's 2024 decision in revenue requirement is not available.

IOU	Wildfire-Related Distribution Revenue Requirement In Rates Year-End 2019 – 2024			Applications at Year-End 2024 For Future Implementation		
	Forecasted Basis (GRC Process)	Historical Basis (Recorded)	Total	Proceeding	Amount Requested or to be Implemented	Basis and Reason*
				WMPMA Track 2 in 2024 GRC A.22-05-016	$0.8	Historical – 2)
				WMPMA Track 3 in 2024 GRC A.22-05-016	$0.6	Historical – 3)

*Reason Codes:
1) authorized in 2024 but not implemented at year-end 2024
2) authorization pending for amount above amount previously authorized for interim rate recovery
3) no authorizations at year-end 2024

For PG&E and SCE, significant wildfire-related operating expenses, including vegetation management efforts and wildfire insurance coverage, began to appear in revenue requirement in rates relative to total revenue requirement starting in 2021, as shown in the blue bars in Figure 10.[106] Wildfire-related capital expenditures (the red slivers on top of the blue bars), such as system hardening e.g. installing covered conductor or undergrounding portions of a distribution system, have continued to gradually increase over the 2021 – 2024 period but are not yet a significant portion of the total revenue requirement in rates. PG&E and SCE have collected a significant portion of historical wildfire mitigation costs incurred to implement WMPs prior to the first GRC each filed with forecasted WMP costs (PG&E's 2023 GRC and SCE's 2021 GRC).[107]

SDG&E shows a lower percentage of wildfire-related revenue requirement to total revenue requirement;[108] however, SDG&E has been revamping and enhancing its wildfire prevention and mitigation measures since 2007, well before the other IOUs, and cost figures reflect a more mature wildfire safety program than those of PG&E and SCE.[109] Further, PG&E and SCE generally began collecting historical wildfire mitigation costs booked in memorandum accounts earlier than SDG&E. SDG&E's recovery of historical wildfire mitigation costs is being determined primarily through its 2024 GRC–its first GRC filing with forecasted WMP costs–delaying recovery of a greater proportion of its historical wildfire mitigation costs compared to PG&E and SCE. The CPUC approved SDG&E's recovery of some 2019 - 2022 wildfire mitigation costs,

[106] The data included in Figure 10 shows that over the 6 year period 2019 – 2024, wildfire-related revenue requirement comprised approximately 15 percent and 10 percent per year on average of total revenue requirement in rates at year-end for PG&E and SCE, respectively.

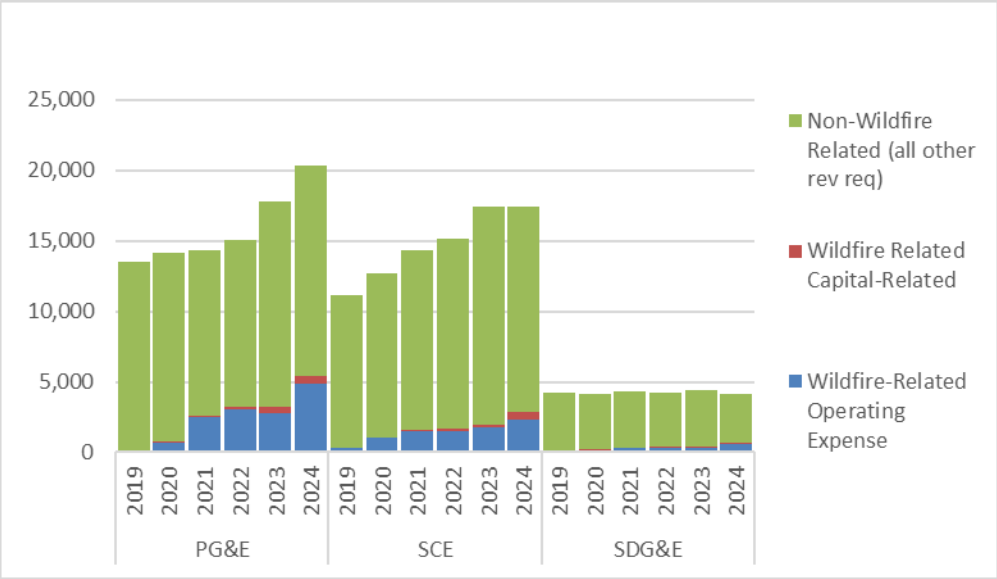
[107] The IOUs may be recording Energy Safety-approved WMP costs over currently authorized GRC costs in memorandum accounts.

[108] The data included in Figure 10 shows that over the 6 year period 2019 – 2024, wildfire-related revenue requirement comprised approximately 8 percent per year on average of total revenue requirement in rates at year-end for SDG&E.

[109] *See* the 2021 SB 695 Report for additional detail about SDG&E operating expenses and capital costs incurred for wildfire prevention over the period 2007 – 2018.

on an interim basis subject to refund, which entered rates in early 2024 and is reflected in the revenue requirement for 2024 in Figure 10.[110] Additional amounts of wildfire mitigation cost recovery related to its requests are expected to be reflected in future reports.[111]

Figure 10: Wildfire-Related Revenue Requirement
Relative to Total Revenue Requirement (Year-End, $ millions)



The year-end 2024 wildfire-related revenue requirement amount is shown in Figure 10 for each IOU.[112]

- PG&E: $5.4 billion, or about 27 percent of total revenue requirement
- SCE: $2.9 billion, or about 17 percent of total revenue requirement
- SDG&E: $685 million, or about 17 percent of total revenue requirement

These wildfire-related revenue requirements, particularly the operating expense revenue requirement, are driving some of the increase in overall utility distribution revenue requirement seen in Figure 2 earlier in this report.[113] However, starting in 2024 and continuing through subsequent years, substantial wildfire-related

[110] D.24-02-010 approved interim cost recovery of 50 percent of SDG&E's request for recovery of $1.188 billion of capital expenditures and $284 million of operating expense recorded 2019 through 2022 in its WMPMA, resulting in authorization to recover a revenue requirement of about $290 million. $194 million of the $290 million entered rates in March 2024 ($194 million over a 10-month period is adjusted to an annual revenue requirement of $233 million).

[111] A final decision on the reasonableness and recovery of SDG&E's 2019 through 2022 WMPMA balance granted partial interim rate recovery is pending in Track 2 of SDG&E's TY 2024 GRC A.22-05-016. In early 2025, SDG&E filed an additional revenue requirement request of $669 million for recovery of 2023 wildfire mitigation costs as part of Track 3 of its TY 2024 GRC A.22-05-016.

[112] Year-end cost and corresponding revenue requirement data may not be captured over the full course of the year. For this reason and also due to regulatory accounting mechanisms, year-end revenue requirement may not reflect amounts actually collected from customers.

[113] CPUC-jurisdictional wildfire-related costs are generally recovered through the distribution rate component; other rate components are the Wildfire Fund Charge (all IOUs) and a wildfire hardening Fixed Recovery Charge (PG&E and SCE).

revenue requirements began to be removed from rates or will be removed from rates because the recovery period for these collections ended or will end, as shown in Table 11.[114]

Table 11: Electric Proceedings Wildfire-Related Revenue Requirement Removed from Rates, By Amortization End Date (Removal Excludes Ongoing Capital-Related Revenue Requirement)

Proceeding (For full proceeding name, click on Decision link in the next column)	Decision	Amortization End Date	Revenue Requirement Impact ($ millions)	Typical Residential Non-CARE Monthly Bill Impact
PG&E				
2022 WMCE	D.23-06-004	7/1/2024	-$1,104	-$9
2021 WMCE Non-VMBA	D.23-08-027	9/1/2025	-$364	-$3
Wildfire and Gas Safety Cost	D.24-03-006	9/1/2025	-$155	-$1
2021 WMCE VMBA	D.24-12-075	3/1/2026	-$503	-$3
2023 WMCE	D.24-09-003	3/1/2026	-$752	-$6
SCE				
WEMA 2	D.23-05-033	6/1/2024	-$214	-$2
2021 CEMA/WEMA	D.23-11-089	1/1/2025	-$137	-$1
2021 GRC Track 2	D.21-01-012	3/1/2025	-$135	-$1
2021 WM/VM	D.24-03-008	6/1/2025	-$379	-$3
2021 GRC Track 3	D.22-06-032	10/1/2025	-$135	-$1
2022 CEMA	D.24-05-037	10/1/2025	-$288	-$3
2022 WM/VM	D.24-07-012	3/1/2026	-$150	-$1
SDG&E				
2024 GRC Track 2	D.24-02-010	2/1/2025	-$241	-$7
CEMA	D.24-07-013	10/1/2025	-$30	-$1

[114] Amortization end date of capital-related revenue requirements not shown; ongoing capital-related revenue requirements are transferred to other cost recovery mechanisms. In addition to amounts shown in Table 11, other generally smaller wildfire-related revenue requirements may have been removed from rates as the result of advice letter dispositions.

Proceeding (For full proceeding name, click on Decision link in the next column)	Decision	Amortization End Date	Revenue Requirement Impact ($ millions)	Typical Residential Non-CARE Monthly Bill Impact
2024 GRC Track 2	D.24-02-010	1/1/2026	-$100	-$3
TTBA	D.24-06-003	2/1/2027	-$36	-$1

These removals reduced the 2024 wildfire-related operating expense represented in Figure 10 (blue bars). However, no capital-related revenue requirements are removed as all capital-related revenue requirements continue to accrue over the life of the underlying assets (red bars). New wildfire-related revenue requirements will also be added over this period as pending proceedings conclude. Furthermore, the IOUs will continue to file new wildfire-related cost recovery applications for costs recorded in wildfire-related memorandum and balancing accounts.

Wildfire-Related Portion of Monthly Bill

Table 12 shows the wildfire-related portion of a bundled residential non-CARE[115] customer average monthly bill resulting from the year-end 2024 wildfire-related revenue requirement (blue and red bars) represented in Figure 10.[116]

Table 12: PG&E, SCE, and SDG&E Wildfire-Related Portion of Average Monthly Bill, Bundled Residential Non-CARE Customers (Year-End 2024)

	Total Monthly Bill	Wildfire Mitigation	Wildfire Liability	Total Wildfire-Related Portion (%)
PG&E	$212	$31	$10	19%
SCE	$159	$17	$10	17%
SDG&E	$153	$11	$10	14%

[115] Residential customers not enrolled in the California Alternate Rates for Energy (CARE) program. Lower-income residential customers enrolled in the CARE program receive up to a 35 percent discount on bills.

[116] Year-end 2024 rates in effect. Typical non-CARE customer using 500 kWh (PG&E climate zone X, SCE climate zone 9) and 400 kWh (SDG&E Inland climate zone). Bills are for illustrative purposes only.

Wildfire-Related Revenue Requirement Projected Growth

Forecasted operations expense and capital-related funding to implement measures directed at reducing wildfire risk are presented in each's IOU's approved WMP. All wildfire-mitigation spend should be captured in the WMP, including wildfire-mitigation cost recovery that may be accruing in SB 901-related or AB 1054-related memorandum accounts. Table 13, below, compares each IOU's wildfire-mitigation cost as shown in the most recently approved WMP, currently the 2025 WMP Update, to each IOU's recently submitted 2026- 2028 Base WMP.[117] The amounts shown are based on the year the cost was incurred (2023 and 2024 actual costs) or is expected to be incurred (2025 - 2028 projected costs) and do not reflect if and when the cost will be authorized for recovery in rates. Accordingly, the data presented here is directional only in terms of the impact on future authorized costs and resulting revenue requirements.[118]

Table 13: 2023 - 2025 WMP and 2026 – 2028 Wildfire Mitigation Cost by Operating Expense (OpEx) and Capital Expense (CapEx)
($ billions)

	2023 – 2025 WMP OpEx	2023 – 2025 WMP CapEx	2023 – 2025 WMP Total Wildfire Mitigation Cost	2026 – 2028 WMP OpEx	2026 – 2028 WMP CapEx	2026 – 2028 WMP Total Wildfire Mitigation Cost
PG&E	$7.2	$9.8	$17.0	$6.3	$12.4	$18.7
SCE	$2.7	$3.4	$6.1	$3.0	$4.0	$7.0
SDG&E	$0.6	$1.6	$2.2	$0.5	$0.5	$1.0

PG&E's 2026 - 2028 WMP cycle projected expenditure data is about 10 percent higher than its 2023 - 2025 cycle data. Immediate impact to PG&E's rates is expected to be less this cycle than the previous cycle, as 2026 - 2028 projected operating expenditures are less than in the previous cycle, with the overall increase in WMP costs attributed to capital expenditures, which enter rates gradually over a longer period of time. Two years of PG&E's 2026 - 2028 WMP cycle, 2027 and 2028, overlap with PG&E's 2027 - 2030 GRC cycle, the application for which was filed May 15, 2025.[119] PG&E states in the 2026 - 2028 WMP that its proposed wildfire mitigations are consistent with those that will be proposed in the 2027 GRC. PG&E also states that

[117] Cost is expenditure and is not stated in equivalent revenue requirement. The 2025 WMP Updates corresponding to the 2023 – 2025 Base WMP for PG&E, SCE, and SDG&E were all approved in 2024 and do not reflect changes in expenditures over those reported in the Base WMP. 2023 – 2025 WMP data is sourced from Table 11 of each IOU's Q4-2024 and Q4-2023 Quarterly Data Response submitted to Energy Safety; 2023 and 2024 is actual data. 2025 – 2028 is projected data. 2026 – 2028 WMP data is sourced from each IOU's Q1-2025 Energy Safety Quarterly Data Response. CapEx is capital expenditure only (i.e. does not include return on rate base).

[118] Projected wildfire liability costs are not captured in WMPs: wildfire insurance is authorized in each IOU's GRC and catastrophic events costs are not projected. *See* "Wildfire Self-Insurance" in the CPUC and IOU "Actions to Limit Cost and Rate Increases" sub-sections later in this section for more information.

[119] *See* A.25-05-009. PG&E's 2027 GRC wildfire mitigation testimony has not been reviewed at time of writing.

is planning to file a 10-Year Electric Undergrounding Plan with Energy Safety in 2025 and that depending on when the plan is approved, PG&E's forecast number of underground miles for 2028 may change from the amount currently included in its 2026 - 2028 WMP. Between PG&E's higher planned spending for the 2026 - 2028 cycle than the approved spend in the previous cycle and the possibility of electric undergrounding spend pursuant to SB 884, PG&E's wildfire mitigation costs, particularly capital expenditures, are expected to continue to grow.

SCE's 2026 - 2028 WMP cycle projected expenditure data is about 15 percent higher than its 2023 - 2025 cycle data, with a proportionately larger increase in projected capital expenditures than in operating expenditures. SCE's 2026 - 2028 WMP cycle is wholly contained within it 2025 - 2028 GRC cycle, the decision for which is currently pending; SCE's 2026 - 2028 WMP may undergo further updates to align it with the requirements and amounts authorized in its final 2025 GRC decision.

While SDG&E's 2026 - 2028 WMP cycle projected expenditure data is almost half of its 2023 - 2025 WMP cycle data, this reduction reflects SDG&E's statement in its 2026 - 2028 WMP that due to reduced funding for strategic undergrounding as a result of the recent decision in its 2024 GRC, SDG&E plans to scale down or suspend ongoing projects in the 2026 - 2028 WMP cycle. SDG&E further states that it is exploring the submission of an Electric Undergrounding Plan in accordance with Senate Bill 884, which could provide funding to resume these projects prior to 2028.

While PG&E and SDG&E have signaled intent to file Electric Undergrounding Plans, none have been filed to date. This means there could be wildfire mitigation related expenditures approved in an Electric Undergrounding Plan that are incremental to the costs shown in the 2026 - 2028 WMPs. For this reason, and for the overall increasing trend in expenditures shown in the WMPs, wildfire mitigation costs are projected to continue their upward trend.

Net Energy Metering and Net Billing Tariffs Cost Impacts

Net energy metering (NEM) tariffs and net billing tariffs[120] (NBT) are available to IOU customers with behind-the-meter renewable electrical generation facilities, such as rooftop solar photovoltaic (PV) systems, with or without energy storage systems. They allow customers who install eligible renewable electrical generation facilities to serve onsite energy and receive credits on their electric bills for surplus energy sent to the electric grid. Almost all customer-sited, grid-interconnected solar PV is interconnected through NEM/NBT tariffs.

Since first implementing NEM tariffs over 25 years ago, California has witnessed the rapid growth of the customer-sited rooftop solar industry, resulting in the installation of over 16.2 gigawatts of clean distributed energy resources.[121]

[120] Includes subtariffs.

[121] As of December 31, 2024. *See* California Distributed Generation Statistics.

Legislative and Regulatory Background

California established the first NEM tariffs in 1997, directed by SB 656 (Alquist, 1995). The first NEM design, now known colloquially as "NEM 1.0," was revised in 2016 per AB 327 (Perea, 2013) when the CPUC adopted the NEM successor tariff now referred to as "NEM 2.0."[122] The CPUC was required by statute to ensure that the NEM successor tariff is based on the costs and benefits of the distributed generation systems, that it achieves various equity-related aims, and that customer-sited renewable distributed generation continues to grow sustainably.[123] In 2022, the CPUC adopted a successor NBT design that balances multiple statutory requirements and the needs of the electric grid, the environment, NEM participants, and all other ratepayers.[124] The NBT also implements higher incentives for customers in low-income households than for other customers.

Table 14 shows the number of bundled residential customers and total customers (bundled and unbundled)[125] on NEM 1.0/NEM 2.0 tariffs and NBT at year-end 2024, with PG&E and SDG&E bundled residential customers on a NEM tariff or NBT representing about one quarter of those IOUs' bundled residential customers.

Table 14: PG&E, SCE, and SDG&E Residential NEM and NBT Customer Counts, Year-End 2024 (rounded to the nearest thousand)

	Bundled Residential			Total Residential (Bundled + Unbundled)		
	Number of Customers on NEM Tariff/NBT	Number of Customers	Percentage of Customers on NEM Tariff/NBT	Number of Customers on NEM Tariff/NBT	Number of Customers	Percentage of Customers on NEM Tariff/NBT
PG&E	463,000	1,815,000	26%	897,000	4,946,000	18%
SCE	536,000	3,255,000	17%	686,000	4,618,000	15%
SDG&E	77,000	283,000	27%	320,000	1,366,000	23%

[122] *See* D.16-01-044.

[123] *See* Public Utilities Code §2827.1(b)(1), §2827.1(b)(3), and §2827.1(b)(4). Customers on NEM 2.0 pay for their cost to connect to the grid, take service on a time-of-use (TOU) rate plan with energy prices based on when and how much energy is used, and pay certain non-bypassable charges that cannot be offset with energy export credits.

[124] *See* D.22-12-056.

[125] Unbundled customers take from the IOU distribution and transmission service only, with generation service provided by a separate entity, usually a Community Choice Aggregator (CCA) or Direct Access (DA) service provider. Figures are combined non-CARE and CARE residential customers.

NEM Program Costs

Under NEM tariffs, customers with on-site generation (primarily rooftop solar photovoltaic (PV) equipment) receive a retail-based credit for the energy they send out to the grid, which offsets the cost of their consumption within the month and within an annual true-up period. The rate, which includes generation, transmission and distribution rates but excludes certain public purpose program and other non-by-passable charges, compensates residential NEM customers at about $0.45/kWh[126] for electricity that, according to the CPUC's 2024 Avoided Cost Calculator (ACC), is worth approximately $0.05/kWh.[127]

The legislature sought to reform NEM because its structure allows rooftop solar customers to avoid paying for their share of the fixed costs that the utility incurs to serve all customers, including rooftop solar customers. When NEM customers self-supply, they avoid paying some of the fixed costs to maintain the electric grid, since these costs are embedded in the volumetric portion of the retail rate. The NEM program results in utility fixed costs being spread across fewer units of usage, that is, fixed costs are absorbed more by customers without rooftop solar, resulting in higher bills for these customers.[128] The NEM design also overpays NEM customers for their exported energy, since NEM customers receive bill credits for their exports at the retail rate, instead of at the price other customers could pay to purchase clean electricity from other sources.

NEM program costs are one of the largest contributors to rising electricity rates for customers that do not have rooftop solar. The NEM program cost shift is currently estimated by the IOUs using a Distributed Energy Resource (DER) cost effectiveness model.[129] This model compares NEM customer bill savings due to self-consumption[130] and netting[131] to the costs the utility avoids due to the operation of the customer's NEM system, such as infrastructure upgrades that the utility should avoid incurring as a result of the distributed generation.

Table 15 shows the IOUs' estimate of the NEM 1.0 and NEM 2.0 cost shift (collectively, the NEM cost shift) and NBT cost shift for all customers[132] (i.e. residential and non-residential) and residential customers only, as of year-end 2024.[133] The NBT is an improvement to the NEM structure and reduces the cost shift

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[126] PG&E E-TOU-C: $0.50/kWh; SCE TOU-D-4-9: $0.37/kWh; SDG&E TOU-DR1: $0.47/kWh. All rates in effect March 1, 2025, and are off-peak and above baseline usage. Figure cited is rounded average of these rates.

[127] ACC costs are modeled based on the following components: generation energy, generation capacity, ancillary services, transmission and distribution capacity, and decarbonization policy compliance. 2024 ACC values for 2025 locked-in export rates (average of generation and delivery rates across all hours). Figure cited is rounded average for PG&E, SCE, and SDG&E.

[128] This occurs because in California, the fixed costs of electricity services are primarily collected through the volumetric distribution rate component of customer bills.

[129] The NEM cost shift is an arithmetic (subtraction) equation based on the Ratepayer Impact Measure ratio in the CPUC's Standard Practice Manual.

[130] Behind-the-meter (BTM) solar generation.

[131] Netting of imports (customer purchase of electricity from the utility) and exports (customer sale of electricity to the utility).

[132] The NEM/NBT cost shift also applies to NEM/NBT customers, although most of this cost burden is shifted to non-NEM customers since much of NEM customers' bills are offset by the NEM systems.

[133] IOU estimates provided in data responses. Data includes a proxy generation rate for unbundled customers that is the same as for bundled customers. PG&E, SCE, and SDG&E modeling includes updated capacity factors from previous modeling.

compared to NEM, since exports are paid at the avoided cost to the utility to buy clean electricity elsewhere. However, a cost shift still remains due to NEM customer's ability to self-supply and avoid paying for some fixed costs to maintain the electric grid as well as programs other customers pay for.

The IOUs estimate NEM/NBT customers shifted approximately $7 billion in costs onto non-participant customers in 2024. This is about 20 percent lower than the 2024 NEM cost shift of $8.5 billion calculated by the Public Advocates Office (Cal Advocates).[134] The difference of about $1.5 billion between the IOUs' and Cal Advocates' cost shifts is due in part to differences in updated capacity factor modeling aligned with what the California Energy Commission (CEC) reported as part of the 2024 Integrated Energy Policy Report (IEPR); this data was not available at the time the Cal Advocates cost shift data was prepared .[135]

Table 15: PG&E, SCE, and SDG&E NEM and NBT Cost Shift, Year-End 2024 ($ Billions)

	All Customers				Residential Customers			
	NEM 1	NEM 2	NBT	Total	NEM 1	NEM 2	NBT	Total
PG&E	$1.2	$2.5	$0.1	**$3.8**	$0.8	$1.9	$0.1	**$2.8**
SCE	$0.7	$1.4	$0.1	**$2.2**	$0.5	$1.3	$0.1	**$1.9**
SDG&E	$0.3	$0.7	$0.0	**$1.0**	$0.3	$0.6	$0.0	**$0.9**
Total	**$2.2**	**$4.6**	**$0.2**	**$7.0**	**$1.6**	**$3.8**	**$0.2**	**$5.6**

NEM costs have increased over the past several years, driven by:

- Higher IOU rates starting in 2021, coincident with higher wildfire-related costs. This results in NEM customers receiving **higher compensation** for the excess energy their systems generate, as they are credited at the retail rate for their generation (which exceeds the cost of other available generation).
- Continuing NEM 2.0 capacity growth from the completion of installations whose interconnection applications were submitted prior to the April 2023 deadline. **Record numbers of NEM 2.0 applications were received from customers during the period from late 2021 to 2023** when the CPUC publicly considered and then set a date for closing enrollment in NEM 2.0. Approximately 2,194 MW and 724 MW of NEM 2.0 capacity came online in 2023 and 2024, respectively.[136] As costs

[134] *See* Cal Advocates' Fact Sheet, "The Rooftop Solar Dilemma" (December 2024).

[135] The IOUs were asked via SB 695 Report data request to submit their NEM cost shift models with capacity factors updated from the 2013 factors contained in the models; the updated capacity factors are aligned with what the CEC has reported as part of the 2024 IEPR process. Other factors that may produce a significant difference between the two analyses are: (1) effective retail rates may be based on different dates and (2) the SB 695 Report numbers calculate cost shifts separately for NEM 1.0 and NEM 2.0 grandfathered customers and non-grandfathered customers, whereas the Cal Advocates numbers are calculated based on all customers being non-grandfathered customers (NEM 1.0 and NEM 2.0 have different compositions of grandfathered customers and tariffs).

[136] California Distributed Generation Statistics, Interconnected Project Sites Data Set; Installations on multi-tenant and multi-property NEM 2.0 tariff variations (Virtual Net Energy Metering and Net Energy Metering Aggregation) are omitted here as these had a later NEM 2.0 sunset date.

associated with legacy NEM 1.0 and 2.0 installations can remain in rates for twenty years, these costs will remain a cost burden to customers without rooftop solar for many years to come.[137]

Starting in April 2023, new rooftop solar customers or prior NEM customers at the end of their 20-year legacy interconnection periods receive compensation through the new NBT. This compensation is more aligned with the value of the generation the systems provide to the grid and includes more favorable price signals for systems with battery storage compared to rooftop solar alone. Existing customers who remain on NEM 1.0 and NEM 2.0 tariffs will continue to receive the full NEM benefits for the remainder of their individual 20-year legacy periods.[138] The costs NEM customers shift onto non-participants will gradually decline as individual legacy periods expire, but the decline will be lengthy and gradual. The last customers to enroll in NEM 1.0 in 2017 will receive that tariff's benefits through 2037, and the last to enroll in NEM 2.0 in 2023 will do so through 2043 (assuming they install in 2023).

The residential NEM/NBT cost shift data in Table 15 is presented in Figures 13 - 15 using a TOU rate that is the rate that most residential NEM customers are on.[139] Cost shift by TOU period is shown as the difference between bill savings (solid areas above the x-axis) and avoided cost (patterned areas below the x-axis) for the TOU period.[140] Bill savings are greatest in the Summer and Winter Off Peak periods (lighter orange and blue colors, respectively), as expected as these hours reflect the highest percentage of NEM system solar generation.[141]

[137] For example, costs associated with NEM 2.0 installations in 2024 will remain in rates until 2044. The majority of NEM customers connected within the last 6 years and about half have 15 or more years of this legacy period remaining, per California Distributed Generation Statistics.

[138] These legacy periods remain in effect when a property with a NEM system changes hands.

[139] While there are modest differences in $/kWh cost shift by TOU period among TOU rates, the primary driver is the proportion of PV generation in each TOU period. Percentage allocations for the representative TOU rate period were calculated for avoided cost, bill savings, and cost shift. TOU periods that are not on-peak are classified off-peak. Electrification TOU rates are insignificant for purposes of this analysis due to the relatively small NBT cost shift, resulting in NBT data being incorporated with NEM data for purposes of the TOU representative rate.

[140] Patterned areas include dotted and diagonal areas for off-peak and on-peak avoided costs, respectively. Diagonal area for on-peak avoided costs amounts may be too small to be graphically represented.

[141] For example, summer off-peak hours generally include the daytime hours prior to 4 pm.

Figure 13: PG&E Residential Bill Savings and Avoided Costs by TOU Period (E-TOU-C, $ Millions)

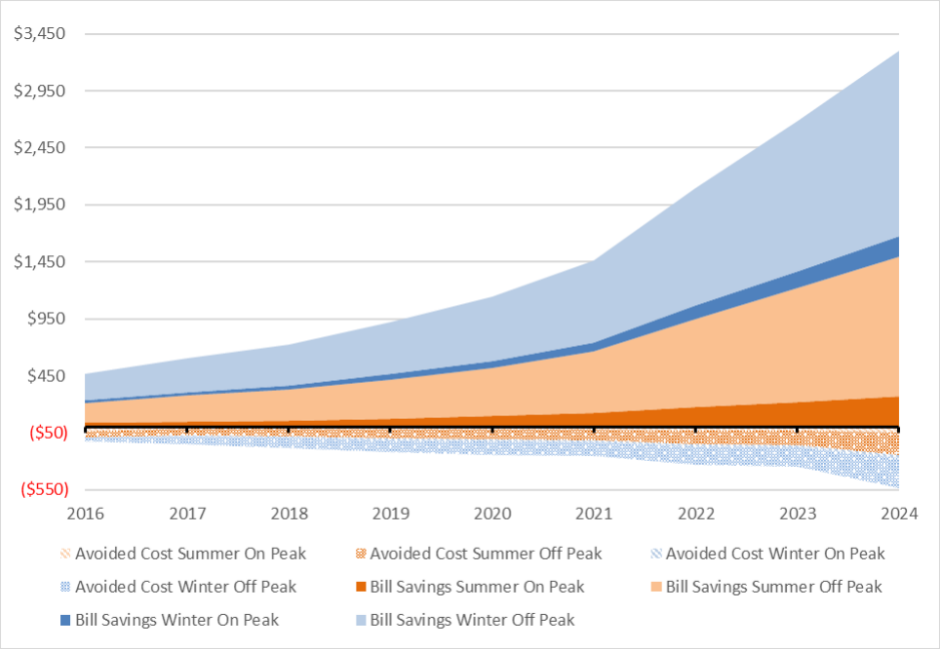


Figure 14: SCE Residential Bill Savings and Avoided Costs by TOU Period (TOU-D-4-9, $ Millions)

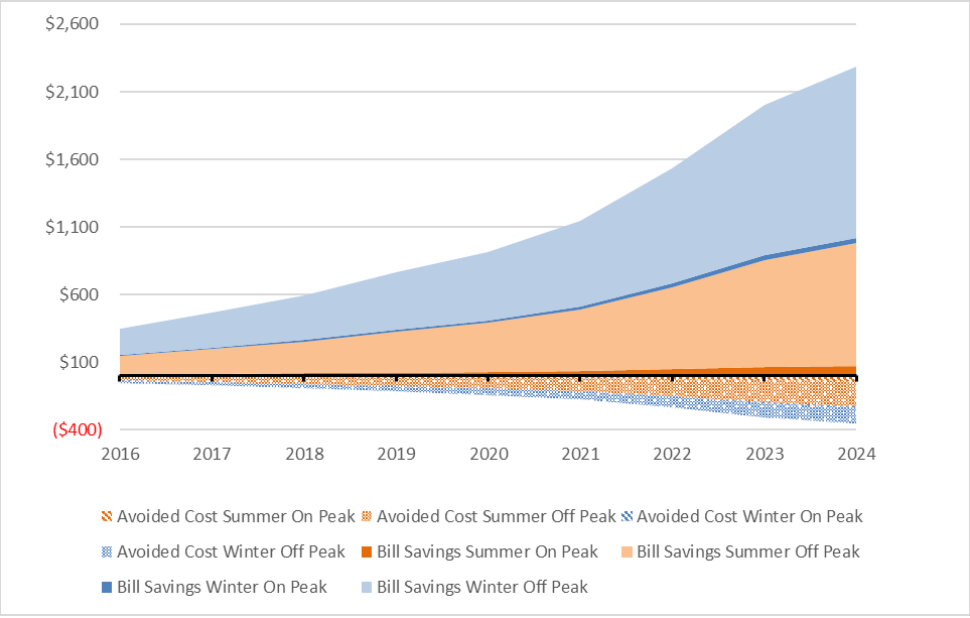
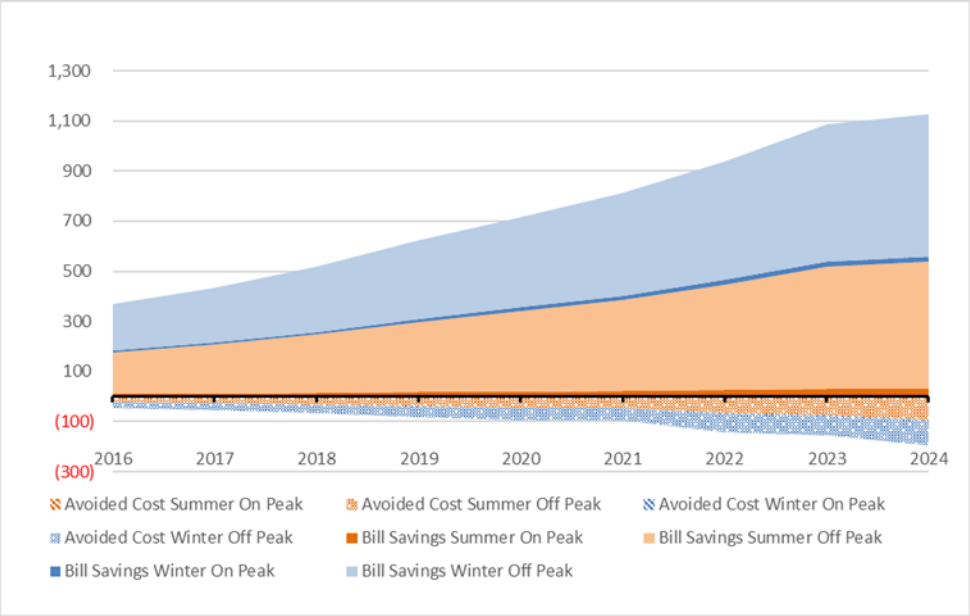


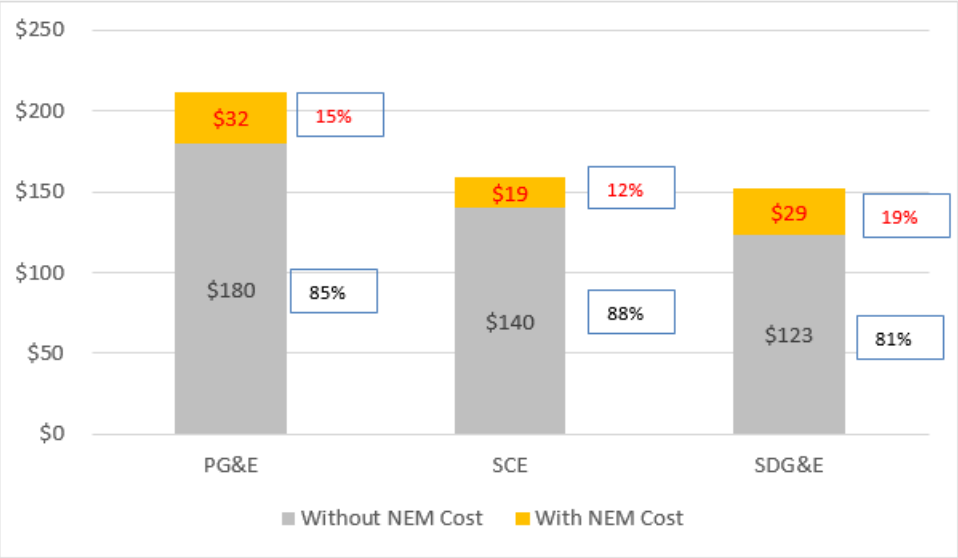
Figure 15: SDG&E Residential Bill Savings and Avoided Costs by TOU Period (TOU-DR1, $ Millions)



The IOUs' NEM cost shift modeling of the estimated NEM cost portion of a typical non-NEM residential customer's bill is shown in Figure 16.[142] The estimated NEM cost portion is shown in yellow as the difference between existing bills and what counterfactual bills would have been if there were no NEM cost shift.

[142] Bill portion modeling is done in each IOU's Cost and Rate Tracker for Q4-2024 with the generation value adjusted as if all customers were bundled, for a typical customer using 500 kWh (PG&E climate zone X, SCE climate zone 9) and 400 kWh (SDG&E Inland climate zone). Usage data primarily reflects non-NEM customers usage data bill data as much of NEM participants' bills are offset by the systems themselves. Results are for a typical IOU bundled residential customer. Unbundled residential customers, such as those who take generation service from a Community Choice Aggregator (CCA), may have different results. NEM cost shift modeling using cost-of-service modeling for a separate NEM-class could result in significantly different results.

Figure 16: NEM Cost Portion of a Typical Non-NEM Residential Customer Monthly Bill (2024)



Bundled Residential Generation Rate

Unlike other utility cost categories, generation costs are only collected from bundled customers and not from unbundled customers served by Community Choice Aggregators (CCA) or Direct Access (DA).[143] This means trends in generation costs should be viewed in the context of declining sales to bundled residential customers, which are highly correlated with load defection by incumbent IOU customers who switch to CCA or DA suppliers. PG&E saw significant bundled load departure to CCAs from 2016 to 2022.[144] SCE experienced significant reductions in bundled load for the period 2019 – 2022, and SDG&E began to experience this effect in 2022 through present. However, departed load is only one factor that can change bundled sales; other factors are the same factors that can change overall retail load such as weather.[145]

Bundled Residential Generation Rate Trends

Changes in the bundled residential generation rate are a function of: 1) the cost variability of the underlying generation **revenue requirement** allocated to the bundled residential class and 2) shifts in bundled

[143] Most residential customers depart from incumbent IOU service to CCA service as opposed to DA service, which tends to be taken up by non-residential customers. A small portion of the generation revenue requirement is recovered from CCA and DA customers through the Power Charge Indifference Adjustment rate, to cover the legacy cost of generation that was secured while the customers were served by the IOU.

[144] *See* 2024 SB 695 Report, p. 33.

[145] Not all changes in bundled sales load are the result of departed load and may not necessarily reflect decreases in load. For example, increased electricity consumption from climate-driven increasing cooling degree days and increased transportation electrification may drive increases in bundled sales load. The change in bundled sales load will thus reflect departed load and other increases or decreases.

residential **forecasted sales**, e.g. load defection to unbundled energy service providers which is usually a CCA. In theory, if a utility is no longer procuring energy for unbundled customers at the same rate as their departure from the IOU (i.e. ,perfectly matched), then the generation rate would remain constant, meaning the effect on rates of load departing to other energy service providers should theoretically be a "wash," or zero.[146] After normalizing for this effect, rising generation rates may result if: 1) the generation revenue requirement is rising due to rising procurement or other costs or 2) forecasted sales are declining due to reasons other than departed load, for example, weather-related causes.[147] The red arrows in Table 16 indicate these possible cases.[148]

Table 16: Combined Effects of Changes in Revenue Requirement and Forecasted Sales on Rates

Case	Combination	Effect on Rates
1	Revenue Requirement ↓ Forecasted Sales ↑	↓
2	Revenue Requirement ↑ Forecasted Sales ↑	Depends on which effect is stronger: If revenue % growth is stronger than sales % growth: ↑ If sales % growth is stronger than revenue % growth: ↓
3	Revenue Requirement ↓ Forecasted Sales ↓	Depends on which effect is stronger: If revenue % decline is stronger than sales % decline: ↓ If sales % decline is stronger than revenue % decline: ↑
4	Revenue Requirement ↑ Forecasted Sales ↓	↑

Figures 17 – 19 show trends in the bundled residential generation rate (blue bars) compared to bundled residential forecasted sales (black line).[149]

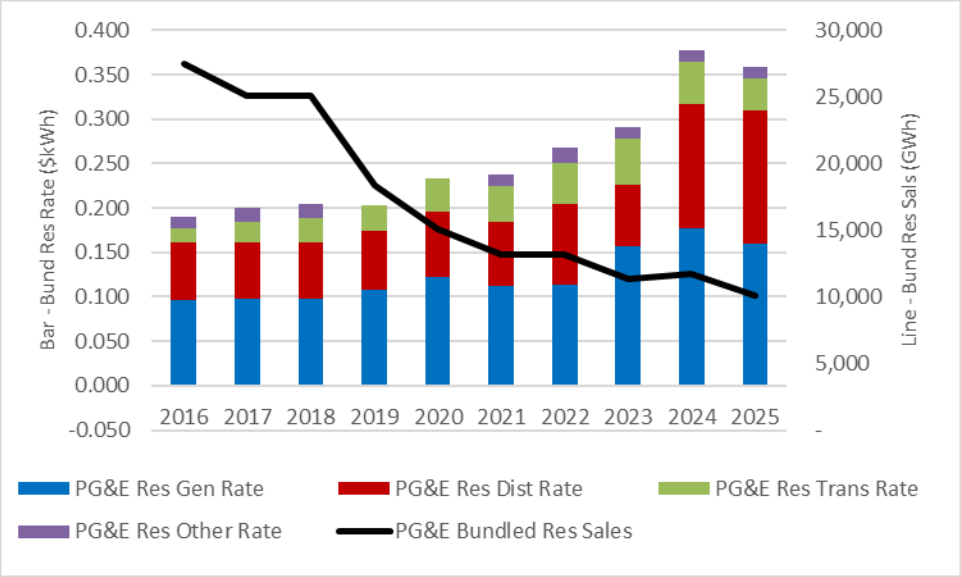
[146] Similar to the effect of departed load, behind-the-meter generation i.e. rooftop solar, would also theoretically result in a "wash" for the generation part of the revenue requirement as the IOU is no longer procuring energy for the behind-the-meter (BTM) generator-customer. Depending on the net metering program structure, BTM solar generation typically represents a one-for-one displacement of retail electricity sales.

[147] Normalization is assumed to reflect the theoretical "wash" case of departed load on procurement costs and rates; this assumption may not be accurate given timing and other differences.

[148] Case 4 shows the case where 1) the generation revenue requirement is rising due to rising procurement or other costs and 2) forecasted sales are declining due to reasons other than departed load, for example, weather-related causes. Cases 2 and 3 apply depending on whether the revenue growth (in percentage terms) or sales decline (in percentage terms) is stronger.

[149] Generation rate includes the Power Charge Indifference Adjustment (PCIA), a rate component intended to equalize certain cost sharing between departed load and bundled load. Bundled residential forecasted sales are calculated as bundled residential revenue requirement divided by the bundled residential rate.

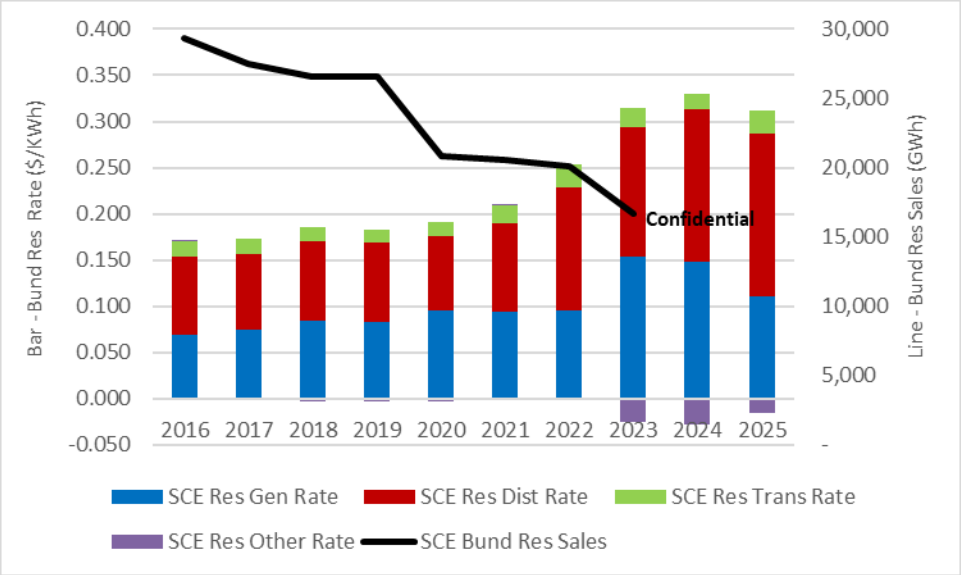
Figure 17: PG&E January 1 Bundled Residential Rates by Generation, Distribution, Transmission, and Other with Bundled Residential Forecasted Sales



For PG&E, the bundled residential generation rate (blue bars) fluctuated slightly from 2016 to 2022 but after that, shows an overall increasing trend.[150] Drilling down into the changes between 2022 and 2025, the generation rates for these years reflect a revenue requirement increase of 7 percent and a forecasted sales decrease of 23 percent (Case 4 in Table 16). This means that after taking into consideration that revenue requirement commensurately declined with departed load, revenue requirement and rates rose for remaining bundled customers.

[150] PG&E's 2023 GRC did not implement until 2024, meaning that primarily the red bars for 2023 and 2024 would have been sized differently if it had implemented on January 1, 2023, i.e. 2023 bars would have been larger and 2024 bars would have been smaller.

Figure 18: SCE January 1 Bundled Residential Rates by Generation, Distribution, Transmission, and Other with Bundled Residential Forecasted Sales

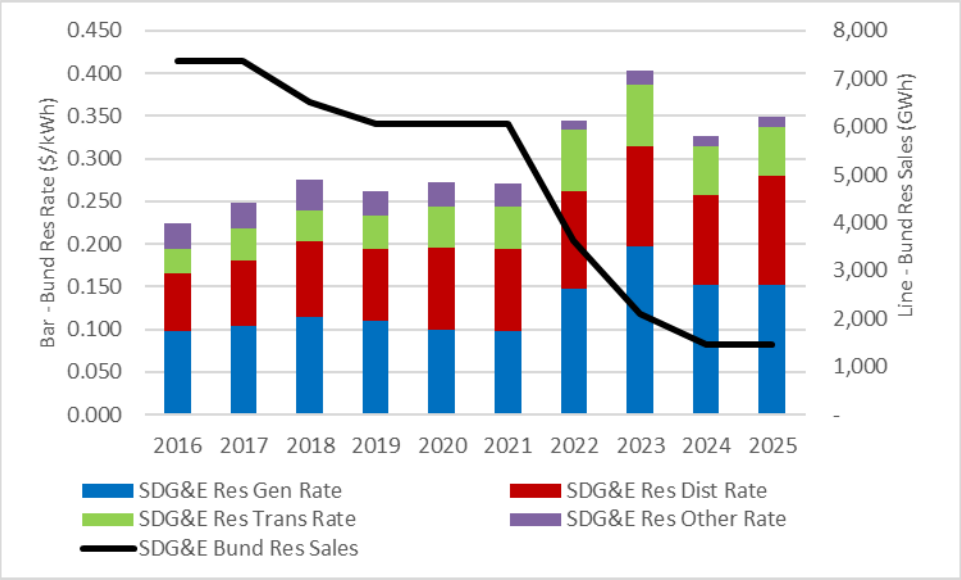


For SCE, the bundled residential generation rate fluctuated slightly from 2016 to 2022 but after that shows an overall increasing trend.[151] Drilling down into the changes between 2022 and 2025 cannot be done as 2024 and 2025 forecasted sales are confidential because of their market sensitive nature;[152] however, the graph reflects Case 4 in Table 16. This means that after taking into consideration that revenue requirement commensurately declined with departed load, revenue requirement and rates rose for remaining bundled customers.

[151] The negative Other Rate (purple bars) primarily reflects the forecasted CARE surcharge amounts that non-participating CARE customers contribute to CARE participating customers i.e. nonresidential revenues that are allocated to residential revenues.

[152] SCE claims confidentiality for its ERRA Forecast proceeding bundled load forecasts for the forecast year and one previous year under D.06-06-066, Matrix section V.C.

Figure 19: SDG&E January 1 Bundled Residential Rates by Generation, Distribution, Transmission, and Other with Bundled Residential Forecasted Sales



For SDG&E the bundled residential generation rate fluctuated slightly from 2016 to 2021 but after that, shows an overall increasing trend. Drilling down into the changes between 2021 and 2025, the generation rates for these years reflect a revenue requirement decrease of 63 percent and a forecasted sales decrease of 76 percent (Case 3 in Table 16). This means that after taking into consideration that revenue requirement commensurately declined with departed load, the decrease in revenue requirement for remaining customers was insufficient to counteract the effect of the decrease in sales and rates rose for remaining bundled customers.

The increase in bundled generation revenue requirement over the 2021 – 2025 period shown in Figures 17 - 19 is significantly influenced by pricing in the wholesale electricity market and by long-term contracts with private generators that reflected market expectations at the time of contract execution.[153] Fluctuations in the generation revenue requirement are driven by factors such as market costs for natural gas and renewables that are largely outside the control of the utilities. However, the bundled generation revenue requirement underlying the bundled generation rate shown in these figures may be rising despite the lowering effect of departed load due, in part, to potential cost sharing imbalances between bundled and unbundled customers.

[153] As the data shown in Figures 17 – 19 is anchored to January 1 each year, timing issues related to late implementation of ERRA Forecast decisions–generally to be implemented on January 1–may be reflected in the data. Other timing issues such as implementation and removal of ERRA Trigger revenue requirement amounts may also distort the data.

Generation Cost Sharing Between Bundled and Unbundled Customers

Long-term clean energy contracts have been essential to meeting reliability needs and have also functioned as a hedge against market volatility. However, older renewables contracts, like those executed in the early 2000s, reflect higher prices than current market prices for renewables, as the immense growth in California's renewables market since the creation of the Renewable Portfolio Standard (RPS) program has helped drive broad decreases in the cost of wind and solar.[154]

Certain long-term generation-related resource costs such as those for RPS are recorded to accounts established to ensure that bundled and unbundled load share these costs equally through the Power Charge Indifference Adjustment (PCIA) mechanism. PCIA-related revenue requirements recover from both bundled and unbundled customers the difference between the actual portfolio cost at the time a contract was executed[155] and current market value–measured using a market price benchmark.

In recent years Resource Adequacy (RA) contracts that the utility must buy to meet its reliability requirements have become more expensive exhibiting extreme increases in the price for system RA, specifically during peak summer months. This has led to rapid increases in the RA market price benchmarks in the past few years, which has increased the market value of IOU portfolios, sometimes leading the calculated portfolio market value to exceed the utility's RA costs. This results in higher generation costs for bundled customers overall and a credit for departed load customers' bills created by a negative PCIA rate, which is paid for by increased rates for bundled customers.

Other Topics of Interest

Rate Base

Rate base primarily reflects the costs of the physical infrastructure needed to deliver electricity to customers. These long-term investments make the system stronger, more resilient, and better able to facilitate electrification of end uses, but infrastructure investments represent sunk costs[156] that must be repaid and therefore limit California's options to reduce rates.

Rate base grows as new authorized capital expenditures are brought into service and layered onto existing capital expenditures.[157] Increases in rate base have a direct relationship with increases in the capital-related revenue requirement as a result of the new capital expenditures' depreciation expense and return on rate

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[154] *See* Figure 5, "Historical Trends of RPS Contract Costs by Technology from 2003 to 2023" in the 2024 Padilla Report for more information on declining RPS contract cost trends.

[155] In the case of utility-owned generation, this may be the cost at the time the asset was placed in service.

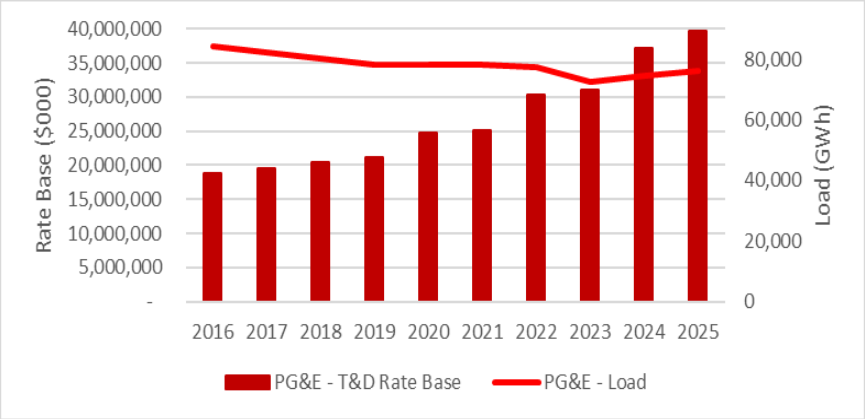
[156] These sunk costs include both depreciation of the asset over time and payment of a rate of return for use of the asset.

[157] *See* Chapter I2 section "Electric Costs, Revenue Requirement, and Rates" for rate base formula. If no new capital expenditures were added, rate base would decline as the underlying investment depreciates over its useful life.

base revenue requirements. If electricity usage does not increase as well, the increased rate base causes higher rates and a corresponding increase in customer bills. The direct relationship between expanding rate base and capital-related revenue requirements has a compounding impact on overall revenue requirement in rates.

Figures 20 - 22 show combined distribution and transmission rate base and retail load delivered by each IOU over the 2016 – 2025 period, with actual load delivered data through 2023 and project load for 2024 and 2025.[158] The year 2023 is the most recent year for which actual load delivered data is available.

Figure 20: PG&E Distribution and Transmission Rate Base (January 1, $000) and Retail Energy Delivered (GWh, 2024 – 2025 Projected)



[158] Rate base shown for net plant/capital additions only, i.e., "other" non-plant/capital additions rate base is not included. Retail load delivered data is from the California Energy Commission (CEC) 2024 Integrated Energy Policy Report (IEPR), California Energy Demand 2023-2040 Planning Forecast, Load Serving Entity (LSE) tables (Mid-Demand); 2016 – 2023 actual data, 2024 – 2025 forecasted data. Retail load delivered may be affected by weather and customer generation, among other factors.

Figure 21: SCE Distribution and Transmission Rate Base (January 1, $000) and Retail Energy Delivered (GWh, 2024 – 2025 Projected)

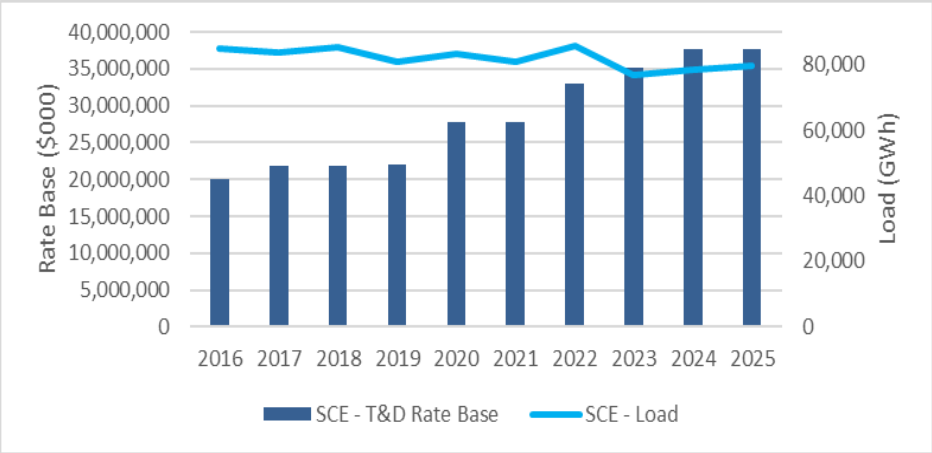
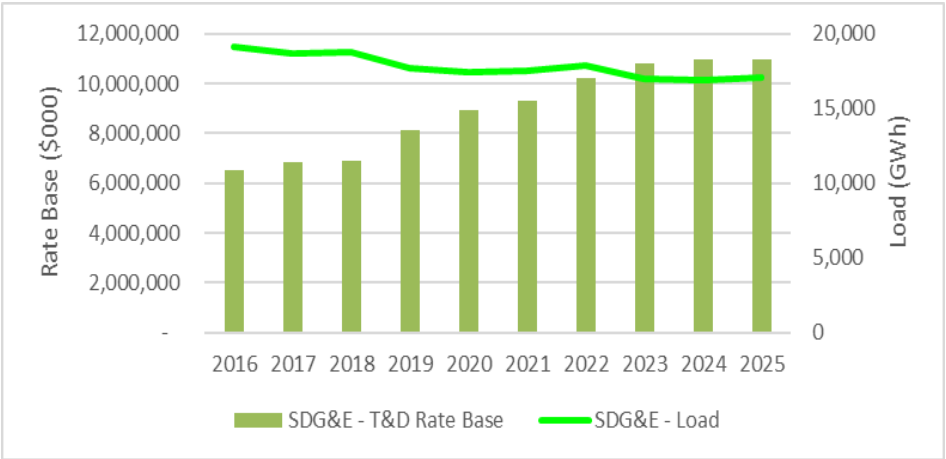


Figure 22: SDG&E Distribution and Transmission Rate Base (January 1, $000) and Retail Energy Delivered (GWh, 2024 – 2025 Projected)



Combined distribution and transmission rate base has been increasing on an average annual percent change basis of approximately 12 percent for PG&E, 10 percent for SCE and 8 percent for SDG&E since 2016.[159] For actual load delivered through 2023, **distribution and transmission rate base growth shows an inverse relationship with volume of load served, with rate base continuing to increase since 2016 while total energy delivered has declined overall since 2016.** The declining load delivered trend is projected to reverse starting in 2024 for PG&E and SCE, with SDG&E load delivered projected to remain

[159] Simplified/smoothing average annual percent calculation of: (end of period value – beginning of period value)/number of periods where periods is a range of years.

relatively flat. Consequently, until rate base growth is matched or outpaced by kWh sales, bundled rates will continue to climb.[160]

Decarbonization through Electrification

To promote California's building-related greenhouse gas (GHG) emissions reduction goals, SB 1477 (Stern 2018) made available $50 million annually for four years, for a total of $200 million, to establish two new building electrification pilot programs: the Building Initiative for Low-Emissions Development (BUILD) Program and the Technology and Equipment for Clean Heating (TECH) Initiative. In response to the passage of SB 1477, the CPUC initiated the Building Decarbonization rulemaking.[161]

In a July 2024 Building Decarbonization Ruling, stakeholders were asked whether measures should be adopted to prevent unnecessary electric service line upsizing. This would include authorizing expansion of existing electric utility testing processes to evaluate non-isolating behind-the-meter devices, such as Meter Socket Adapters, that attach to the utility meter and enable adding load to an existing service line without need for electric service line upsizing. Once evaluated and approved, such technologies would potentially result in significant ratepayer savings and customer savings, in addition to eliminating wait-times for utilities to install new infrastructure. On June 12, 2025, the CPUC adopted D.25-06-034, which established a pathway for the evaluation and eventual deployment of non-isolating behind-the-meter devices.

Electrifying the transportation and building sectors and other new loads are critical decarbonization strategies. To support electrification efforts, the large IOUs forecast substantial investments to upgrade electrical distribution and/or transmission capacity to provide adequate capacity to new and existing electricity customers. Assembly Bill (AB) 50 (Wood, 2023) established criteria for customers to receive timely energization and potential remedies to expedite energization. Senate Bill (SB) 410 (Becker, 2023) requires the establishment of reasonable average and maximum target energization time periods in order to connect new customers and upgrade the service of existing customers to the electrical grid. In response to AB 50 and SB 410, the CPUC launched a rulemaking to establish energization timing targets and data reporting processes.[162]

PG&E is the first utility to request a ratemaking mechanism under SB 410.[163] Pursuant to SB 410's mandate, the CPUC authorized PG&E to record approximately $2.3 billion in capital additions to support

[160] While PG&E and SCE load delivered is projected to increase about 1 percent for each utility over the 2023 – 2025 period, rate base grew at a higher rate than 1 percent, meaning rate base growth continues to outpace kWh sales and bundled rates will continue to climb despite projected load growth.

[161] *See* R.19-01-011.

[162] *See* R.24-01-018.

[163] D.24-07-008 in A.21-06-021 authorized PG&E to establish the ECNBIMA to record and track costs related to energization projects completed between January 1, 2024, and December 31, 2026. Cost recovery of ECNBIMA amounts are on an interim rate recovery basis, subject to reasonableness review in PG&E's next general rate case.

energization-related distribution upgrades for the period 2024 to 2026.[164] In August 2025, PG&E received approval to track an additional $1.5 billion above the previously authorized capital additions amount to complete energization-related customer requests between 2025 and 2026.[165] Equivalent revenue requirements for these approved costs have not yet entered rates. SDG&E has filed an application requesting a ratemaking mechanism under SB 410 to record up to $310 million of incremental energization-related capital additions between 2024-2026.[166] SCE in its 2025 GRC requested approximately $2.6 billion in capital expenditures for 2025 through 2028 for load growth purposes. Load growth covers work needed to support customer load growth, including transportation electrification load and distributed energy resources (DER) growth throughout SCE's electric grid.[167] SDG&E's additional funding request pursuant to SB 410 and SCE's GRC load growth funding request are currently being reviewed in each respective proceeding and the costs, at their approved revenue requirement equivalent, will be in rates at a future date.

An important consideration regarding the affordability of electrification is a household's full energy portfolio, which seeks to capture the totality of energy costs a consumer bears, inclusive of electricity, natural gas, and fuel for transportation. Tracking only household electric or gas bills can miss contributors to customers' monthly energy expenditures. For example, switching to an electric vehicle means saving at the gasoline pump that would not be revealed by tracking electricity usage–and billing–alone. SB 3264 (Petrie-Norris, 2024) and AB 2462 (Calderon, 2024) require the CPUC develop a framework for assessing, tracking, and analyzing total annual energy costs paid by residential households in California by December 31, 2026 and to include in the SB 695 report consideration of how the adoption of decarbonization policies, including electrification, may impact household total energy costs. Bill impact scenarios resulting from the total energy cost framework that will be developed will be included in a future SB 695 report.

Transmission Buildout Capital Expenditures

To meet California's clean energy goals, the California Independent System Operator (CAISO) has begun approving unprecedented levels of transmission investment.[168] Between 2022 and 2024 the CAISO approved over $16 billion in new transmission expansion projects, consisting of new lines and substations, reconductoring, other upgrades, and some grid enhancing technologies. The costs of such high voltage transmission projects are allocated throughout California, with the greatest share attributed to the transmission assets of PG&E, SCE, and SDG&E. To the extent that these projects support increasing load, however, they could put downward pressure on rates by allowing costs to be spread out among a greater

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[164] D.24-07-008 capped PG&E's annual revenue requirements associated with its energization projects at $144.310 million in 2024, $91.568 million in 2025, and $99.071 million in 2026. These revenue requirement figures correspond to capital expenditures of $975 million in 2024, $618 million in 2025, and $669 million in 2026, for a total of $2.262 billion.

[165] PG&E energization-related distribution upgrades are not broken down into categories such as transportation electrification-related.

[166] *See* A.25-04-015.

[167] SCE's Transportation Electrification Grid Readiness (TEGR) request, included in this request, comprises over one-third of the work SCE identified.

[168] *See* the 2024 AB 67 Report available here for more information regarding transmission costs that comprise the transmission revenue requirement, as well as more information on how the CPUC intervenes in TO rate cases at FERC on behalf of California ratepayers. Ratepayer savings from this intervention are estimated to exceed $5.4 billion since 2017.

number of customers and units of electricity, although the rate impacts depend on how quickly anticipated new loads materialize.

As has been the case for years, the majority of capital spending on transmission projects has been on utility self-approved repair and replacement projects, which are used for maintaining the grid but receive no formal review and approval by the CAISO. Only those projects that are approved in CAISO's Transmission Planning Process (TPP) for grid expansion or included in large generator interconnection agreements (LGIA) in CAISO's generator interconnection process receive CAISO review. According to the most recent data in the CPUC's Transmission Project Review (TPR) Process, between 2020 and 2024, of the total $11.7 billion in transmission capital expenditures by the three IOUs, $8.7 billion (about 75 percent) was invested in self-approved projects that received no formal review and approval in their planning by the CAISO.

In 2024, the CPUC began the TPR Process to provide transparency to all specific projects, as well as programmatic buckets or blanket program categories (collectively "Projects"), that are Utility Self-Approved, CAISO TPP-approved, or included in LGIAs in CAISO's generator interconnections process.[169] Projects are included if they are expected to total $1 million or more in capital costs. The TPR Process requires that the IOUs semi-annually submit system-wide transmission data for projects with capital additions to rate base in the last five years and forecasted or actual capital expenditures in the current year and future four years, to enable understanding of project planning, prioritization, and implementation. The TPR Process is modeled after stakeholder processes negotiated in previous transmission owner rate case settlements at FERC. While not always quantifiable, savings from those FERC-derived processes and the TPR Process between 2020 and 2024 resulted in long-term savings to ratepayers of between $500 million and $1 billion.[170]

The decades-long recovery timeframe for capital investments results in the related revenue requirement in any given year being a fraction of a capital project's total cost. However, over the depreciable life of a capital investment, the depreciation expense[171] and corresponding rate of return (including return on equity for shareholders) result in long-term costs to ratepayers that can be multiple times higher than the initial project cost.[172] In July 2024, CAISO updated its 20 Year Transmission Outlook, estimating that in the next two decades, between $45.8 and $63.2 billion[173] of investment in new transmission capacity on the high voltage transmission system will be needed to meet reliability needs and the state's clean energy goals. This amount does not include ongoing self-approved projects and capacity build out of lower-voltage transmission. Together, this investment in transmission buildout is expected to lead to continuously mounting capital-related transmission revenue requirements.

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[169] *See* Resolution E-5252 and the Transmission Project Review Process webpage.

[170] A conservative estimate is that for every dollar added to rate base, it costs ratepayers $3.50 over the depreciable life of an asset. If a dollar is expensed rather than capitalized, that one-for-one pass through saves ratepayers approximately $2.50 of that $3.50 in long-term costs. For every dollar of capital costs fully removed from rates, ratepayers would receive the full $3.50 in benefits. Various adjustments and removal of costs resulting from these stakeholder processes have yielded these estimated long-term savings.

[171] Net of related tax effect.

[172] *See* Figure 1 for an example of how a $1 billion capital expenditure cost over 40 years can balloon to 3.5x the original $1 billion investment.

[173] *See* California ISO, 20 Year Transmission Outlook, July 2024.

V. Bundled Residential Electric Rates Forecast

Projected Rate and Bill Impacts

As part of the Affordability proceeding, the CPUC ordered PG&E, SCE, and SDG&E to each submit a quarterly cost and rate tracker (CRT) tool to Energy Division for evaluating the inputs of the affordability metrics.[174] Each IOU's CRT may be used to produce a four-year–current year plus three years–rate forecast[175] to show overall bundled residential average rate trends and estimated bills at IOU climate zone level.[176]

Bundled Residential Rate Forecasts

PG&E's, SCE's, and SDG&E's current electric CRTs were used to produce rate forecasts.[177] Projected rates in this report are forecasts, including assumptions related to those forecasts, and are therefore subject to material change as assumptions change. Further, forecasts are based on forward-looking estimates that are not historical facts. Forecasts are for illustrative purposes only and solely for use in this report. Bundled residential average rate forecasts for year-end 2025 – 2028 are shown in Table 17.[178]

[174] *See* D.20-07-032 in R.18-07-006, Ordering Paragraph (OP) 1. CRTs are available on the CPUC's Affordability webpage. SCE's CRT has certain information labeled confidential.

[175] Energy Division staff may modify the rate forecasts as submitted by the IOUs to reflect estimates for cost recovery applications not yet filed and account for historical trends in revenue requirement and rates. Forecasts do not take into account future natural gas price spikes, which are difficult to predict. Forecasts also do not take into account future NEM/NBT cost shifts, except to the extent that they may be reflected in historical trends in revenue requirement and rates.

[176] Climate zones are drawn in each IOU's service territory based on climactic variation and are also known as baseline territories as defined by each IOU in its Preliminary Statements.

[177] Current CRTs are for first quarter 2025 (Q1-2025) with current rates effective March 1, 2025 for all IOUs. Rates include the California Climate Credit (CCC) which functions as a revenue requirement reduction. PG&E and SDG&E CRT sales forecasts held at currently authorized sales forecasts; SCE CRT sales forecasts are estimated 2025-2028 sales forecasts.

[178] Projected rates do not reflect rate design such as changes resulting from the Base Services Charge Decision (D).24-05-028. Under current rate design, PG&E and SDG&E forecasted residential rates have no fixed charge; SCE has an approximately $1/month fixed charge.

Table 17: PG&E, SCE, and SDG&E Forecasted Bundled Residential Average Rates (nominal $/kWh)

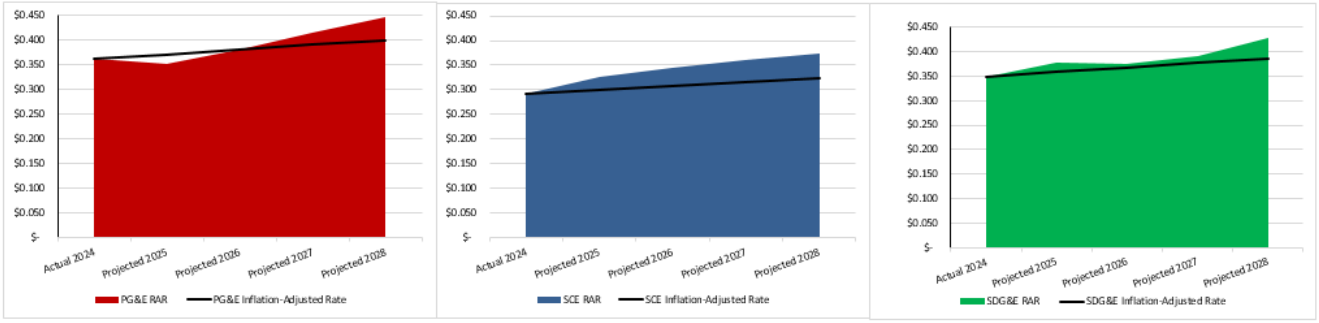
Bundled Residential Average Rate	Year-End				
	Actual 2024	Projected 2025	Projected 2026	Projected 2027	Projected 2028
PG&E Nominal Rate	$ 0.361	$ 0.350	$ 0.380	$ 0.414	$ 0.445
SCE Nominal Rate	$ 0.293	$ 0.325	$ 0.344	$ 0.361	$ 0.374
SDG&E Nominal Rate	$ 0.349	$ 0.378	$ 0.375	$ 0.390	$ 0.427

The percentage change in forecasted year-end 2028 bundled residential rates over actual year-end 2024 rates for each IOU are shown below. The average annual increase is a simplified average whereby the total percentage change is divided by the number of years in the forecast period.

- PG&E: about 23 percent through 2028 for an average annual increase of about 6 percent
- SCE: about 28 percent through 2028 for an average annual increase of about 7 percent
- SDG&E: about 22 percent through 2028 for an average annual increase of about 6 percent

Rate trends allow comparison of how an IOU's rates track another metric, inflation, over time. Inflation is typically used as a benchmark for electric rate growth because it has traditionally been assumed that household incomes rise at about the rate of inflation, thus if electric rates increase at the same rate then the affordability of electric service should remain unchanged for the average household. However, while inflation generally affects the costs underlying the utility's revenue requirement, rates and bills are impacted by other factors, such as wholesale natural gas prices, high interest rates, and supply chain challenges. The average annual percentage change in forecasted year-end 2028 rates over actual year-end 2024 rates for each IOU is greater than the assumed average annual rate of inflation of 2.6 percent as shown in Figure 23.[179]

Figure 23: PG&E, SCE, and SDG&E Electric Bundled Residential Average Rates ($/kWh)

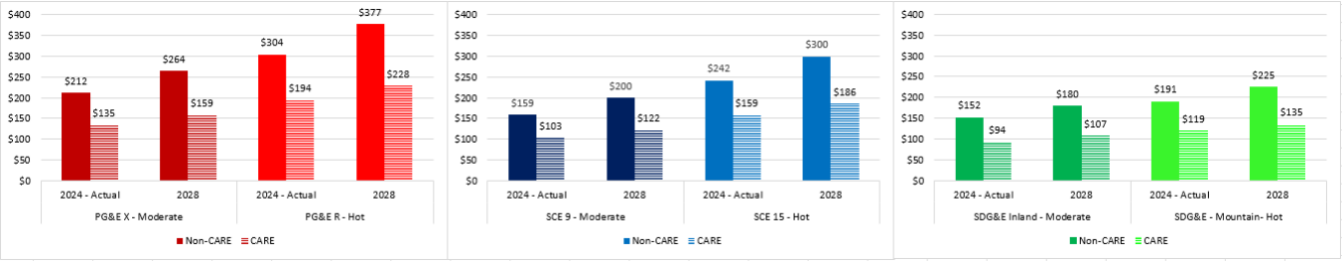


Bundled Residential Bill Forecasts

[179] Inflation rate is based on the Consumer Price Index (CPI), California Region, All Items, All Urban Consumers, reported by the California Department of Finance (DOF), available here (CPI Forecast Data published November 2024).

Figure 24 shows the projected monthly bill increase resulting from the Table 17 rates forecast based on: (1) the usage amounts the IOUs use in their legal bill inserts[180] for a typical customer living in a *moderate* climate zone[181] – 500 kWh per month for PG&E and SCE, and 400 kWh per month for SDG&E and (2) a usage amount for a typical customer living in a *hot* climate zone[182]–700 kWh per month for PG&E and SCE, and 500 kWh/month for SDG&E.[183] Average[184] electricity bills for a customer living in one of these two climate zones are shown below. All projected bill increases are greater than the assumed average annual rate of inflation of 2.6 percent.[185]

Figure 24: PG&E, SCE, and SDG&E Current and Projected Residential Average Monthly Bills, Year-End 2024 – Year-End 2028 Typical Customer Living in a Moderate and Hot Climate Zone



Electric Bill Affordability

Affordability of utility services cannot be measured based on the magnitude of utility bills alone. Electricity and natural gas are essential services; consumers require them to maintain a healthy living standard and meaningfully participate in society. Unlike products or services that customers are able to forego if prices rise too high, essential utility services will generally continue to be consumed regardless of price.

[180] In compliance with Rule 3.2(d) of the CPUC's Rules of Practice and Procedure, the IOUs are to provide notice of, among other things, proposed residential rate changes addressed in a utility's application. Bill impacts for a typical residential customer usually accompany these rate changes in a bill insert sent to customers known as the "legal bill insert." *See* monthly usage data in legal bill inserts for PG&E's 2023 General Rate Case (GRC), SCE's 2025 GRC, and SDG&E's 2024 GRC.

[181] "Moderate" climate zones are also sometimes referred to as "warm" climate zones, as opposed to "cool" or "hot." Bills for a typical customer living in a moderate climate zone are calculated based on PG&E climate zone X, SCE climate zone 9, and SDG&E Inland climate zone.

[182] Hot climate zones are as defined in D.17-09-036, Decision Adopting Findings Required Pursuant to Public Utilities Code § 745 for Implementing Residential Time-of-Use Rates. Bills for a typical customer living in a hot climate zone are calculated based on PG&E climate zone R, SCE climate zone 15, and SDG&E Mountain climate zone. PG&E climate zone R includes Fresno County and other areas in the San Joaquin Valley; SCE climate zone 15 includes Riverside County and other areas in the Coachella Valley; and SDG&E Mountain climate zone includes the mountainous area of San Diego County, commonly referred to as East County.

[183] Bills are for illustrative purposes only.

[184] Bill is averaged over the calendar year.

[185] Inflation rate 2024 base year to 2028 is 2.6 percent/year, based on Consumer Price Index (CPI), California Region, All Items, All Urban Consumers, reported by the California Department of Finance (DOF), available here (CPI Forecast Data published November 2024).

The CPUC has developed effective tools for measuring current and future affordability by geographic location and considering the cost of utility services in relation to the socioeconomic condition of different households. One key metric is the Affordability Ratio (AR) which quantifies the percentage of a representative household's income used to pay for an essential utility service after non-discretionary expenses, such as housing and other essential utility services, are removed from the household's income. The higher an AR, the less affordable the utility service. The AR metric is sensitive to geographic variations in cost-of-living[186] and can be calculated for any of the four essential services individually (electricity, natural gas, water, and communications) or for the combined bundle of essential services. AR may also be calculated for any income level in an area, with AR_{20} (the AR for a household at the 20th percentile income level) and AR_{50} (the AR for a household at the median, or 50th percentile, of income) used as the standard representations.[187]

The AR_{20} provides an additional means of tracking affordability to supplement data tracking rate and bill trends, by considering customer income and certain cost-of-living data to highlight affordability issues for the most disadvantaged customers. The CPUC has been generating AR_{20} data since 2019; data is available on the CPUC's Affordability webpage.[188] Figure 25 shows each IOU's electricity service AR_{20} time series data for selected moderate and hot climate zones.[189]

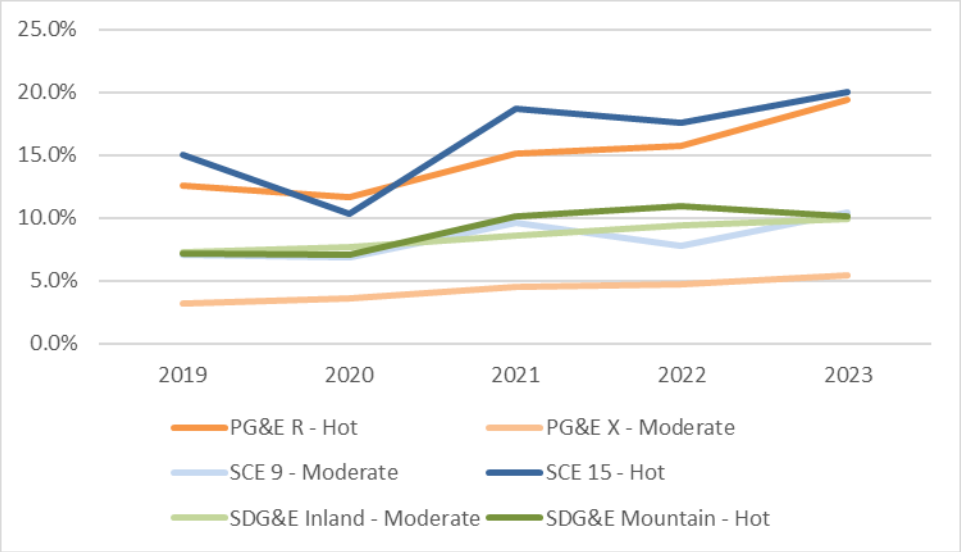
[186] The AR calculation uses income and housing cost data form the Census Bureau's American Community Survey (ACS)that is estimated for geographic areas known as Public Use Microdata Areas (PUMA). PUMAs are non-overlapping, statistical geographic areas that partition each state or equivalent entity into geographic areas containing no fewer than 100,000 people each. There are currently 265 PUMAs in the state of California.

[187] The 20th percentile represents households that are low-income but may not necessarily qualify for an assistance program such as California Alternate Rates for Energy (CARE). AR_{20} data does not account for the impact of low-income programs such as CARE and FERA, thus characterizing the affordability of electricity service for low-income customers who do not necessarily qualify for or seek assistance.

[188] For the most recently published data, *see* the 2021 and 2022 Annual Affordability Refresh. 2023 data represented in Figure 25 was in draft form at time of report preparation; 2023 data is subject to change when published.

[189] AR_{20} in annual Affordability Reports is produced using an Affordability Ratio Calculator (ARC) vintaged to each annual Affordability Report year, except for 2019 data which was re-stated in the 2020 annual Affordability Report due to a change in methodology. *See* individual annual Affordability Reports for this change and other changes in methodology for other years, available on the CPUC's Affordability webpage.

Figure 25: PG&E, SCE, and SDG&E Electric AR20
Selected Moderate and Hot Climate Zones



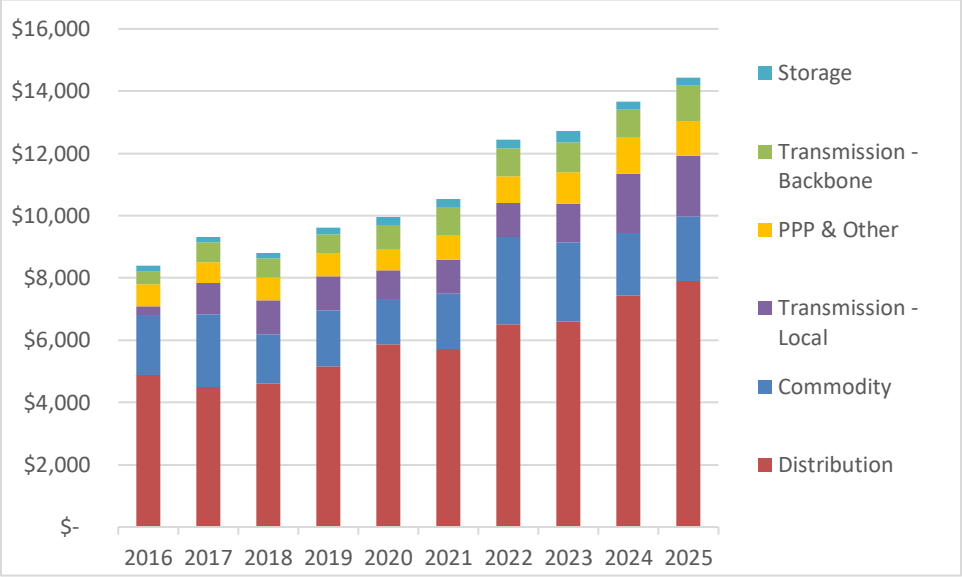
VI. Natural Gas Revenue Requirements and Rate Trends

Changes to Utilities' Revenue Requirements

Overview

Historical revenue requirement trends provide insight into the revenue-drivers impacting gas utility service. Figure 26 below illustrates the major gas utilities' combined yearly revenue requirements dating back to 2016. The revenue requirements illustrated in Figure 26 are graphed by gas rate categories.[190] The largest revenue driver is the gas distribution revenue requirement rate category. The second largest revenue driver has typically been the commodity revenue requirement rate category, which varies annually based on wholesale gas market conditions. The combined gas revenue requirement of California's three largest gas utilities has increased by 72 percent this past decade.

Figure 26: SoCalGas, PG&E, and SDG&E Combined Gas Revenue Requirement by Rate Category (January 1, $ millions)



[190] Storage, transmission (backbone and local) and distribution revenue requirements adopted in general rate cases include operating costs, annualized capital depreciation costs, taxes, and authored return on rate base. The annualized capital depreciation costs are amortized over an assets' useful life and therefore represent a fraction of the total capital costs that are adopted in General Rate Cases and other cost-recovery proceedings.

Gas customers are divided into two categories: core and noncore. Core customers receive gas procurement and delivery services from the utilities. Noncore customers receive gas delivery services from the utilities but purchase their gas separately from third-party suppliers, such as producers (extract gas from wells), marketers (buy and sell gas), and brokers (intermediate between buyers and sellers of gas). Residential and small commercial customers generally fall into the core category. While some core customers choose to have a third-party CTA procure their gas, utilities are responsible for procuring and delivering natural gas to most core customers. Noncore customers are large commercial and industrial customers, including electric generators, refineries, hospitals, and manufacturers.

The sections below examine the changes to each utility's revenue requirement between 2016 and 2025.[191] They are broken down to show changes for different components of the utilities' gas delivery systems as well as commodity and PPP costs. Broadly speaking, the gas system includes backbone transmission, local transmission, distribution, and storage. The utilities' backbone transmission system consists of large diameter, high pressure pipelines that connect to the interstate pipeline system, bringing gas from receipt points at the California border to the local transmission and distribution system. Local transmission pipelines transport gas from the backbone system and storage fields to the distribution system. Distribution pipelines are smaller diameter, lower pressure pipelines that bring gas from the local transmission system to customers. Transmission pipelines are more expensive to build and operate than distribution pipelines, but there are far more miles of distribution pipelines. Based on PG&E's 2023 Gas Safety Plan and Sempra's 2024 GRC testimony, there are 10,100 miles of intrastate transmission pipeline and 103,617 miles of natural gas distribution pipelines in California.[192] Distribution costs are borne primarily by core customers, as large noncore customers more often receive their gas directly from transmission pipelines.[193]

Storage is part of the gas infrastructure system, but it also impacts gas commodity costs. Storage is essentially a form of insurance and supply, providing a local source of gas that can be accessed when demand exceeds pipeline supply, when there are disruptions on the pipeline system, or when gas prices are high. Thus, discussions of national and international gas price trends often focus on gas storage levels and whether they are above or below the five-year average. The CPUC requires gas utilities to hold set amounts of storage for core customers to provide reliability, resiliency, and price protection. Noncore customers make their own choices about whether to procure storage.

In the sections below, recent revenue requirement trends for the following categories are included for each utility: commodity,[194] backbone transmission, local transmission, distribution, storage, and PPP and other costs.

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[191] The source of these data is the utilities' January through February 2025 responses to the Energy Division's data requests. The core procurement revenue is based on annualized estimates; all other revenues are based on authorized revenue requirements.

[192] Sources: PG&E's 2023 Gas Safety Plan; Exhibits SCG-04-R-E, SCG-06-2R-E, SCG-10-R, SDGE-04 and SDGE-06 of Application 22-05-015/-016 (Sempra 2024 GRC).

[193] Noncore customers consume about 65 percent of the natural gas delivered by California's natural gas utilities.

[194] The core procurement revenue is based on annualized estimates.

Commodity revenues cover the costs incurred by the utilities for procurement activities undertaken on behalf of core gas customers which include the gas commodity costs, net hedging costs, interstate capacity costs, and brokerage fees.

Backbone transmission revenues include depreciated capital expenditures, operations and maintenance (O&M) costs, and administrative and general (A&G) costs. These costs include the federally mandated Transmission Integrity Management Program (TIMP)[195] and state-mandated Pipeline Safety Enhancement Plan (PSEP) costs.

Local transmission revenues include depreciated capital expenditures, O&M costs, and A&G costs recovered for local transmission pipelines, including TIMP and PSEP costs.

Distribution revenues cover costs related to service lines, regulators, meters, meter reading, and billing as well as the costs for maintaining and operating high and medium pressure distribution pipelines, which include the cost associated with the Distribution Integrity Management Program (DIMP).[196]

Storage costs include depreciated capital expenditures and O&M costs of operating natural gas storage facilities, including well testing in accordance with CalGEM regulations and other aspects of the utilities' Storage Integrity Management Program (SIMP).[197]

The PPP and "Other" costs include the costs for the California Alternate Rates for Energy (CARE) program, energy efficiency (EE) and low-income EE, and the gas public interest research and development program, which is administered by the California Energy Commission (CEC).

PG&E Revenue Requirement by Rate Category

PG&E's 2025 gas operations revenue requirement consists of various rate categories whose year-over-year changes and service functions are explained below. The revenue requirement collected through these categories fund the operation of approximately 6,500 miles of gas transmission pipelines, 43,700 miles of gas distribution pipelines, and three gas storage facilities that serve approximately 4.7 million gas meters from Bakersfield to the Oregon border.[198] PG&E's distribution and local transmission costs are collected via gas transportation rates. Core customers pay for an allocated share of backbone transmission and storage costs

[195] TIMP requires operators to create and implement a plan to continually evaluate threats to their transmission pipelines, rank those threats, and take appropriate action to mitigate them as outlined in the Code of Federal Regulations (CFR) Title 49, Subpart O, §192. The plan must identify High and Medium Consequence Areas and use assessment methods such as inline inspection, hydrostatic testing, or direct assessment to monitor the integrity of pipelines in those areas.

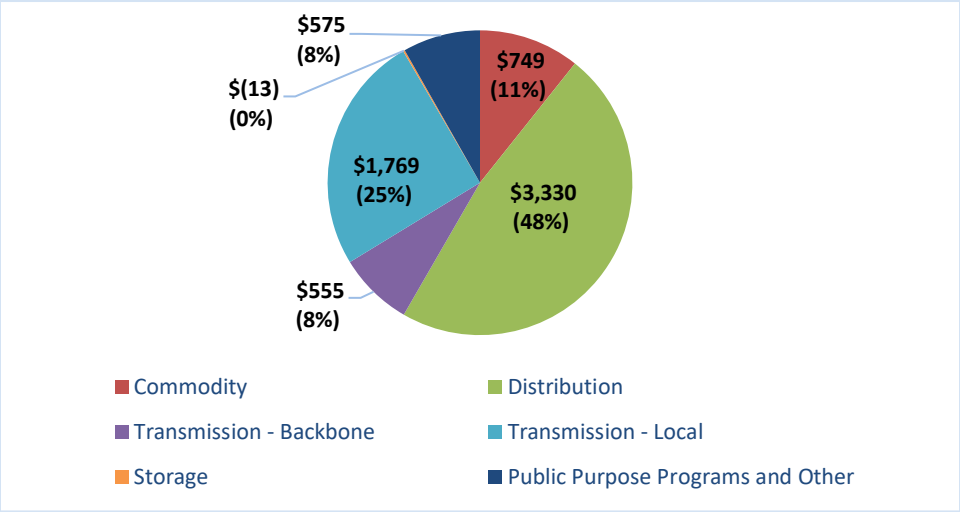
[196] The DIMP program helps identify threats to the system's distribution pipeline integrity, ranks the relative risk of each threat, and implements regulations over and above regulatory minimum requirements, if justified by the degree of risk. The DIMP program also tracks performance measures to determine if the additional actions are effectively reducing risks. Unlike TIMP, no specific integrity assessment methods are required.

[197] SIMP requirements are set by PHMSA and CalGEM under 49 CFR, Part 192.12 and Title 14, Chapter 4, §1726 of the California Code of Regulations (CCR) respectively and are intended to identify and manage threats to the functional integrity of storage wells and reservoirs. Operators must periodically reassess storage wells using proscribed methods, identify existing and potential threats, and remediate them.

[198] Source: PG&E's 2023 Gas Safety Plan.

in the core gas procurement rate. PG&E core customers also pay for storage obtained from independent storage operators through the core gas procurement rate.

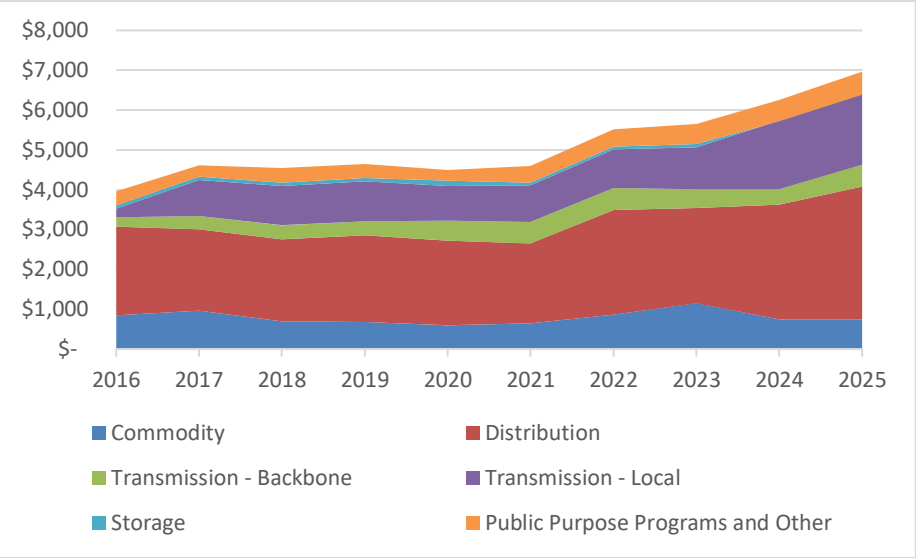
Figure 27: PG&E 2025 Revenue Requirement by Rate Category
($ millions/percentages)[199]



PG&E's 2025 total gas operations revenue requirement is $6,966 million, representing a 76 percent increase since 2016. This 10-year increase is largely attributed to funding work necessary to keep PG&E's gas infrastructure operating reliably and the need to comply with state and federal pipeline safety regulations. From 2024 to 2025, PG&E's total gas operations revenue requirement increased by 11.3 percent. See Figure 28.

[199] Data is from IOU responses to Energy Division SB 695 Report data requests, submitted to CPUC in January through March of 2025.

Figure 28: 2016–2025 PG&E January 1 Revenue Requirement by Rate Category ($ millions)[200]



Year-Over-Year Changes In PG&E's Gas Operations Revenue Requirement Rate Categories

In 2025, PG&E projects a year-over-year increase to its total gas operations revenue requirement due to the following drivers. First, the 2023 General Rate Case (GRC) Decision (D.23-11-069) adopted gas operations revenues that cover O&M expenses, depreciated capital costs, taxes, and a rate of return on invested capital – these revenues are impacted by the 2025 "post-test year" revenue escalation factor[201] also adopted in D.23-11-069. Second, the 2025 gas operations revenue requirement includes the under-collection of the 2023 revenue requirement resulting from the late adoption of D.23-11-069 which will be collected over 24 months, through December 31, 2025. Third, the gas operations revenue requirement includes separately funded programs such as Wildfire Mitigation and Catastrophic Events, Wildfire Gas and Safety Costs, and the Oakland General Office Purchase. Fourth, year-end balances from various regulatory accounts[202] are included in the 2025 gas operations revenue requirement.

Commodity (+0.2 percent): PG&E's 2025 commodity-related revenue requirement forecast is projected to remain relatively flat compared to 2024. The forecast includes the weighted average cost of gas PG&E will purchase for core customers and associated interstate capacity costs, gas hedging costs, and brokerage fees.

[200] Data is from IOU responses to Energy Division SB 695 Report data requests, submitted to CPUC in January through March of 2025 .

[201] The post-test year revenue escalation factor incorporates expected cost increases driven by inflation, capital additions or replacements, and changes in operation. Post-test year revenue escalation factors were adopted for 2024 through 2026.

[202] Include regulatory accounts such as the Core and Noncore Fixed Cost Accounts, Residential Uncollectibles Balancing Account, and the Mobilehome Park Balancing Account.

Backbone Transmission (+40.3 percent): The year-over-year increase to the 2025 backbone transmission revenue requirement rate category is driven by forecasted backbone transmission pipeline integrity work, which includes in-line inspections, strength testing, valve automation, and pipeline replacement. The backbone transmission system (BTS) includes Lines 2, 300, 400 and 401. It is used to transport gas from interstate pipelines, other local distribution companies, and California gas fields to PG&E's local transmission and distribution system.

Local Transmission (+3.6 percent): PG&E's local transmission revenue requirement rate category will increase due to the implementation of D.23-11-069, which adopted an increase in transmission pipeline integrity work such as inspections, assessments, and strength testing. The local transmission system consists of pipelines that accept gas from the BTS and transport it to the distribution system**.**

Distribution (+15.8 percent): The primary drivers of the increase in the distribution revenue requirement rate category are the Alternative Energy Program, Gas Service Customer Response, and Leak Management and Corrosion Control Program. Additional drivers are the Wildfire Gas and Safety Costs Interim Rate Relief, which recovers recorded costs in memorandum and balancing accounts related to wildfire and gas safety; the under-collection in the Core Fixed Cost Account (CFCA), which was primarily driven by the late implementation of PG&E's Gas Cost Allocation and rate Design Proceeding (D.24-03-002); and warmer than average weather during the winter months, which lowered PG&E's gas sales. Transportation rates are based on forecasted gas sales; lower than forecasted sales results in revenue under-collections which are recovered via higher rates the following year.

Storage (+21.7 percent): The main driver of PG&E' storage revenue requirement rate category increase – from a negative $16.3 million in 2024 to a negative $12.7 million in 2025 – is the late implementation of D.23-11-069, resulting in a revenue requirement under-collection amortized from January 1, 2024, through December 31, 2025.[203] The net negative $12.7 million storage revenue requirement rate category in 2025 results from PG&E's decision not to sell the Los Medanos storage field.[204] Storage services include customer gas storage and carrying cost of working gas in storage for core customers.

Public Purpose Programs and Other (+4.5 percent): The total PPP revenue requirement rate category increase was driven by Energy Efficiency revenues authorized in Decision 23-06-055, the forecasted CARE shortfall,[205] and PPP balancing account under-collections. A tabulation of the various PPP revenue requirement components and their year-over-year differences and changes are included below. (**Note:** In 2025, the difference between the total $469.8 million PPP revenue requirement in the table below and the

[203] The 2024 SB 695 Report indicated that the revenue requirement for storage facilities negatively affected PG&E's total 2024 revenue requirement, mainly due to a decline in work at the McDonald Island storage facility. However, in 2025, PG&E clarified that although revenue associated with the work performed at the McDonald Island facility was lower, it was not the main reason for the decrease in storage-related revenue. The primary factors driving the decrease in the 2024 storage revenue requirement were the same as those reported for 2025.

[204] PG&E planned to sell the Los Medanos storage field, which resulted in the collection of depreciation and decommissioning revenues per D.19-09-025. However, PG&E decided to retain the Los Medanos storage field and refund the associated depreciation and decommissioning revenues to core customers through December 31, 2025.

[205] The forecasted CARE shortfall represents the forecasted revenues collected from non-CARE customers necessary to fund the 20 percent discount provided to CARE customers.

$575.2 million "PPP and Other" revenue requirement included in Figure 28 is the PPP "Other" component. The PPP "Other" revenue requirement component includes revenue categories such as greenhouse gas debits and credits, the hazardous substance balance, and the GT&S revenue sharing mechanism.)

Public Purpose Program Revenue Requirements ($000s)	2024	2025	Percentage Change
California Alternate Rates for Energy (CARE)	$ 213,143	$224,810[206]	5.5%
Energy Savings Assistance (ESA) Programs[207]	$70,669	$85,631[208]	21.2%
Energy Efficiency (EE)	$104,648	$145,745[209]	39.3%
School Energy Efficiency Stimulus Program (SEESP)	$0	$0	N/A
Market Transformation Administrator (MTA)	$0	$1,784	N/A
Research, Development and Demonstration (RD&D) Programs[210]	$10,659	$11,409	7.0%
California Department of Tax and Fee Administration (CDTFA)	$417	$429	2.9%
Total	**$399,536**	**$469,808**	**17.6%**

SoCalGas Revenue Requirement by Rate Category

SoCalGas' 2025 revenue requirement consists of various rate categories whose year-over-year changes and service functions are explained below. The revenue requirement collected through these rate categories fund the operation of approximately 3,385 miles of gas transmission pipelines, 51,670 miles of gas distribution pipelines, and four storage facilities that serve approximately 5.9 million meters in an area of roughly 24,000 square miles, stretching from Visalia in the north to the Mexico-U.S. border, and as far east as the California-Nevada border. [211]

[206] The 2025 gas CARE revenue requirement of $224.8 million includes the forecast of the gas CARE discount to be provided to low-income customers in 2025, gas CARE administrative costs, and the recovery of the recorded 2024 CARE balancing account balance.

[207] The ESA program is a no-cost energy efficiency program that provides home weatherization services and energy efficiency measures to help low-income households conserve energy and improve the health, comfort, and safety (HCS) of the home.

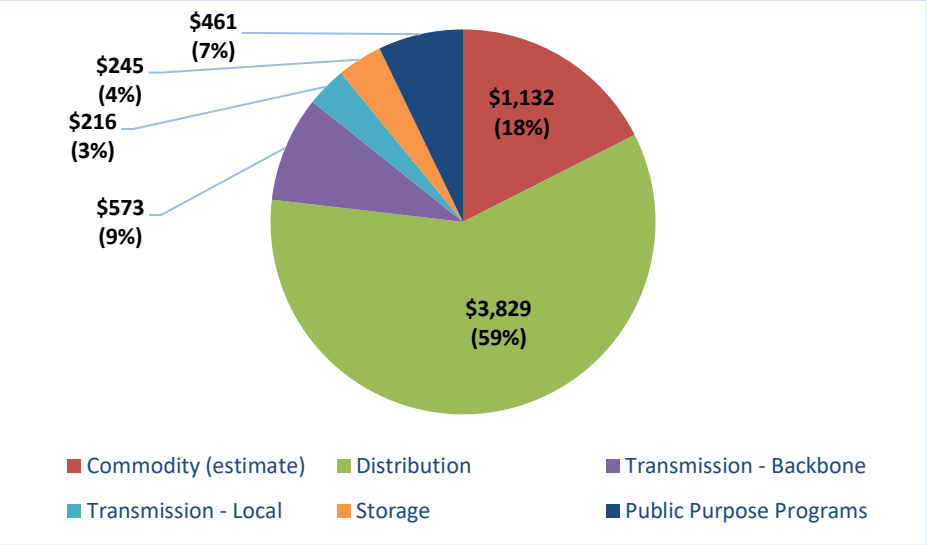
[208] The 2025 gas ESA revenue requirement of $85.6 million includes the 2025 ESA program revenue requirement and the recovery of the recorded 2024 ESA balancing account balance.

[209] The 2025 gas EE revenue requirement of $145.7 million includes the 2025 EE revenue requirement, including the Market Transformation Administrator (MTA), and the recovery of the recorded 2024 EE balancing account balance.

[210] The gas RD&D program was established by the CPUC in 2004, pursuant to Assembly Bill 1002, and is administered by the California Energy Commission's Energy Research and Development Division.

[211] Source: Exhibit SCG-04-R-E, SCG-06-2R-E, and SCG-10-R of Application 22-05-015/-016 (Sempra 2024 GRC).

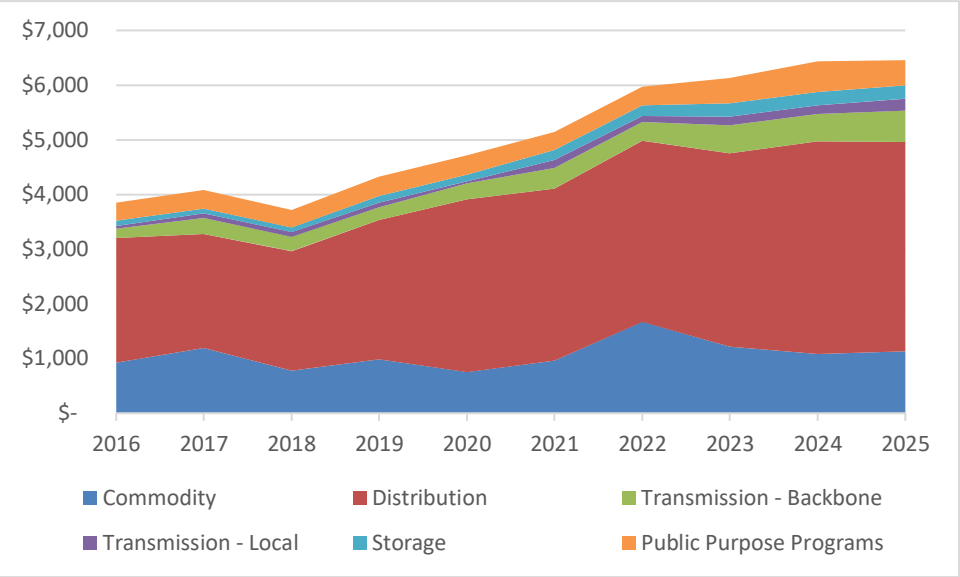
Figure 29: SoCalGas 2025 Revenue Requirement by Rate Category ($ millions/percentages)[212]



SoCalGas' 2025 revenue requirement is $6,456 million, representing a 67.6 percent increase since 2016. From 2024 to 2025, SoCalGas' total revenue requirement increased slightly, by 0.2 percent. See Figure 30.

[212] Data is from IOU responses to Energy Division SB 695 Report data requests, submitted to CPUC in January through March of 2025.

Figure 30: 2016–2025 SoCalGas January 1 Gas Revenue Requirement by Rate Category ($ millions)[213]



Year-Over-Year Changes In SoCalGas' Operations Revenue Requirement Rate Categories

In 2025, SoCalGas projects a slight year-over-year increase to its total revenue requirement[214] due to the net impact of the following drivers. First, net changes in revenues recorded in the regulatory balancing accounts result in a $192.9 million revenue requirement decrease.[215] Second, a reduced California Alternate Rates for Energy (CARE) subsidy lowered the total 2025 Public Purpose Program revenue requirement by $100 million. Third, Decision 24-10-008 modified SoCalGas' Cost of Capital Mechanism (CCM) adjustment ratio to 20 percent, resulting in a $28.9 million revenue requirement decrease.

Commodity (+4.0 percent): SoCalGas' procurement department projects a year-over-year increase to its commodity-related revenue requirement due to an increase in the forecasted weighted average cost of gas it will purchase on behalf of core customers in 2025.

Backbone Transmission (+14.8 percent): SoCalGas' backbone transmission revenue requirement rate category will increase due to the Transmission Integrity Management Program Balancing Account (TIMPBA) and the Safety Enhancement Capital Cost Balancing Account (SECCBA) balances, which are

[213] Data is from IOU responses to Energy Division SB 695 Report data requests, submitted to CPUC in January through March of 2025.

[214] The 2024 GRC Decision (D.) 24-12-074 and the Cost Allocation Proceeding, D.24-07-009, were implemented on February 1, 2025, via Advice Letter (AL) 6430-G-A. The revenue requirement impacts resulting from these decisions are not reflected in SoCalGas' 2025 total revenue requirements included in Figure 29 and Figure 30. SoCalGas AL 6430-G-A reflects a total 2025 revenue requirement increase of $636.7 million.

[215] Per SoCalGas Advice Letter 384-G-A, the balancing accounts driving the net change were Backbone Transmission Balancing Account, Residential Uncollectible Balancing Account, Greenhouse gas balancing account, and Core Fixed Cost Account.

partly offset by a decrease in the Backbone Transmission Balancing Account (BTBA) balance. SoCalGas' pipelines are classified as backbone transmission if they receive gas from receipt points mainly along the California-Arizona border and transport it to SoCalGas' storage fields and local transmission system.

Local Transmission (+35.9 percent): SoCalGas' local transmission revenue requirement rate category will increase due to the TIMPBA balance. Local transmission pipelines transport gas from backbone pipelines and storage fields to the SoCalGas' distribution system. SoCalGas does not plan to derate transmission pipelines in 2025.[216]

Distribution (-1.5 percent): SoCalGas' distribution revenue requirement rate category decreased slightly, from $3,886 million in 2024 to $3,829 million in 2025. SoCalGas' distribution revenue requirement covers customer-related meter and billing costs, medium and high-pressure distribution pipelines costs, and costs related to balancing accounts.

Storage (0 percent): SoCalGas' storage revenue requirement rate category remained unchanged.[217] SoCalGas' natural gas storage facilities include gas wells, compressors, pipelines and various buildings and ancillary equipment.

Public Purpose Programs (-17.9 percent): SoCalGas' PPP revenue requirement rate category decreased by $100 million. Lower forecasted CARE customer sales volumes and lower, per therm, commodity costs reduced the CARE subsidy, lowering the total PPP revenue requirement relative to 2024. A tabulation of the various PPP revenue requirement components and their year-over-year differences and changes are included below.

Public Purpose Program Revenue Requirements ($000s)	2024	2025	Difference	Percentage Change
California Alternate Rates for Energy[218]	$ 272,251	$172,217	-$100,034	-36.7%
Energy Efficiency (DSM)	$165,867	$166,376	$509	0.3%
Low Income Energy Efficiency	$111,508	$107,550	-$3,958	-3.6%
RD&D – Common Good	$11,380	$12,882	$1,501	13.2%
Bureau of Equalization	$476	$488	$12	2.52%

[216] SoCalGas indicated it will derate transmission pipelines when operating conditions permit, within the guidance provided by D.23-12-003.

[217] SoCalGas' $245 million storage revenue requirement has been constant from 2023 to 2025. It changes when SoCalGas conducts embedded costs studies.

[218] The CARE revenue requirement is collected from non-CARE customers to fund the CARE customer discount.

Public Purpose Program Revenue Requirements ($000s)	2024	2025	Difference	Percentage Change
SJVDACBA[219] – BTM balance	$0	$1,778	$1,778	N/A
SJVDGPMA[220]	$91	-$62	-$153	-168.1%
Total	$561,574	$461,229	-$100,345	-17.9%

SDG&E Revenue Requirement by Rate Category

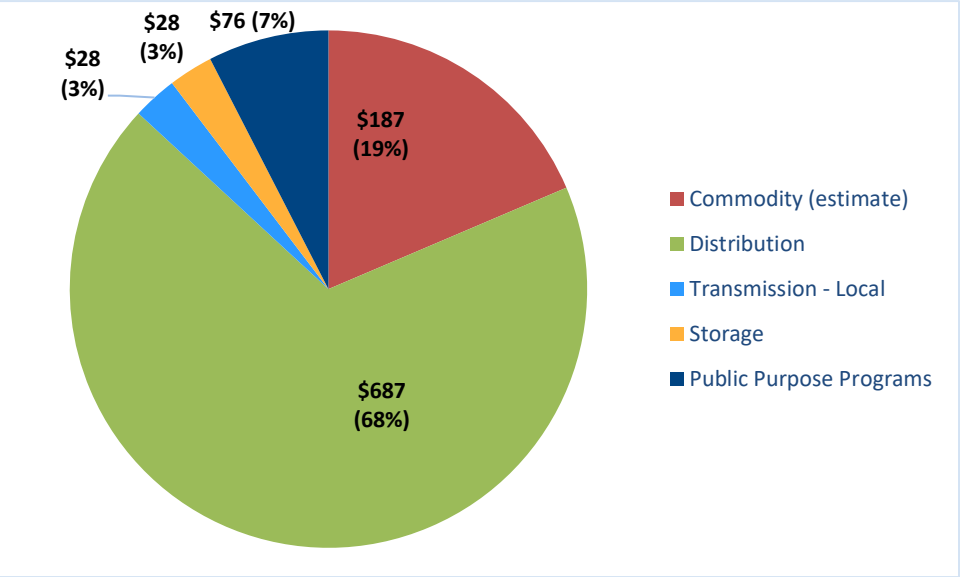
SDG&E's 2025 revenue requirement consists of various rate categories whose year-over-year changes and service functions are explained below. The revenue requirement collected through these rate categories fund the operation of approximately 215 miles of gas transmission pipelines and 8,247 miles of gas mains serving approximately 900,000 meters in an area of over 1,400 square miles, stretching from Orange County in the north to the Mexico-U.S. border in the south.[221]

[219] The San Joaquin Valley Disadvantaged Communities Balancing Account tracks beyond-the-meter pilot costs authorized in D.18-12-015.

[220] The San Joaquin Valley Data Gathering Plan Memorandum Account.

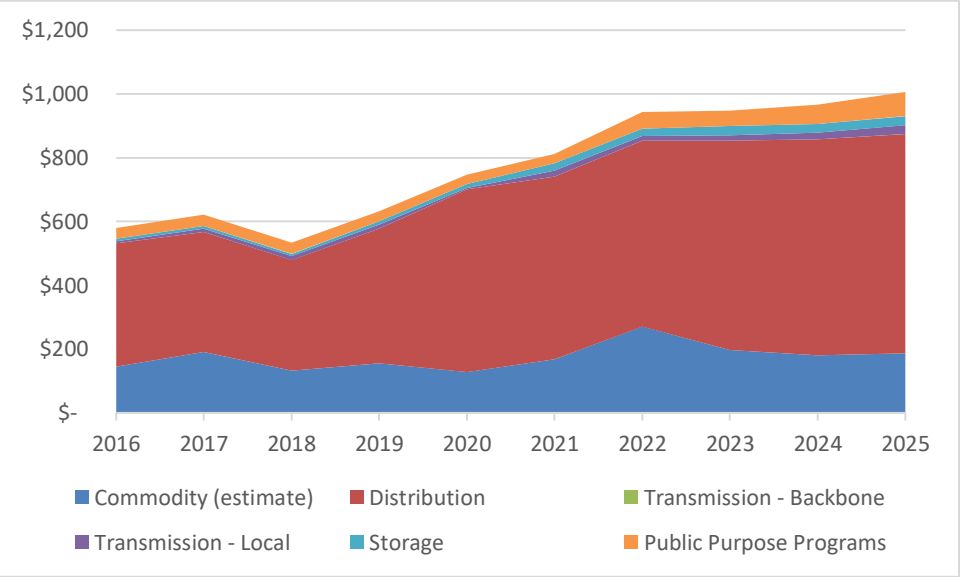
[221] Source: Exhibits SDGE-04 and SDGE-06 of Application 22-05-015/-016 (Sempra 2024 GRC).

Figure 31: SDG&E 2025 Revenue Requirement by Rate Category
($ millions/percentages)



SDG&E's 2025 gas operations revenue requirement is $1,006 million, representing a 74 percent increase since 2016. From 2024 to 2025, SDG&E's total gas operations revenue requirement increased by 4 percent. See Figure 32.

Figure 32: 2016-2025 SDG&E January 1 Gas Revenue Requirement by Rate Category
($ millions)



Year-Over-Year Changes In SDG&E's Operations Revenue Requirement Rate Categories

In 2025, SDG&E projects a year-over-year increase to its total gas operations revenue requirement primarily due to the net impact of the following drivers. First, the net revenue requirement under-collections recorded in regulatory balancing accounts increased the revenue requirement by $39.2 million.[222] Second, the net changes to the Public Purpose Program (PPP) revenue requirement increased the total 2025 revenue requirement by $14 million. Third, Decision 24-10-008 modified SDG&E's Cost of Capital Mechanism Adjustment ratio to 20 percent and Return on Equity to 10.23 percent, resulting in a $4.5 million revenue requirement decrease.[223]

Commodity (+3.9 percent): SDG&E's projects a year-over-year increase to its commodity-related revenue requirement due to an increase in the forecasted weighted average cost of gas purchased on behalf of core customers.

Local Transmission (+33.3 percent): SDG&E's local transmission revenue requirement rate category increased by $7 million due to work associated with the Transmission Integrity Management Program (TIMP) described in SDG&E Advice Letter 3312-G[224]. Local transmission pipelines transport gas from backbone pipelines and storage fields to the SDG&E's distribution system. SDG&E does not plan to derate transmission pipelines in 2025.[225]

Distribution (+1.5 percent): SDG&E forecasts a slight increase in the distribution revenue requirement rate category. The distribution revenue requirement covers customer-related meter and billing costs, medium and high-pressure distribution pipelines costs, and the amortization of balancing account balances.

Storage (0 percent): SDG&E's storage-related revenue requirement rate category remained unchanged. Natural gas storage facilities include gas wells, compressors, pipelines and various buildings and ancillary equipment.

Public Purpose Programs and Other (+24.6 percent): SDG&E's PPP revenue requirement rate category increased by $14.7 million in 2025. A lower CARE subsidy[226] partially offset the higher revenue requirements associated with the Energy Efficiency and Energy Savings Assistance programs. A tabulation of the various PPP revenue requirement components and their year-over-year differences and changes are included below.

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[222] The net $39.2 million revenue requirement increase is primarily due to the total net under-collection recorded in SDG&E's Core Fixed Cost Account (CFCA), Master Meter Balancing Account (MMBA), and the Residential Uncollectible Balancing Account (RUBA).

[223] *See* SDG&E AL 3383-G, page 2.

[224] SDG&E AL 3312-G implemented a functionalized allocation of the TIMP Balance Account amount into SDG&E's gas transportation rates.

[225] SDG&E indicated it will derate transmission pipelines when operating conditions permit, within the guidance provided by D.23-12-003.

[226] Lower 2025 forecasted CARE customer sales volumes and lower, per therm, commodity costs reduced the CARE subsidy.

Public Purpose Program Revenue Requirements ($000s)	2024	2025	Difference	Percentage Change
California Alternate Rates for Energy (CARE)227	$ 29,155	$19,834	-$9,321	-32.0%
Energy Efficiency	$22,596	$40,192	$17,596	77.9%
Energy Savings Assistance (ESA/LIEE/DAP)	$7,006	$14,341	$7,335	104.7%
RD&D – Common Good	$2,184	$1,276	-$907	-41.53%
Bureau of Equalization	$47	$52	$5	10.64%
CPUC	$0	$0	$0	0%
Total	$60,987	$75,696	$14,709	24.1%

Average Rates by Customer Class

Broadly speaking, gas customers are divided into core and noncore customers. The utility purchases gas for core customers, who consist of mostly residential and small or medium commercial customers. Noncore customers are large commercial and industrial customers such as electric generators, hospitals, and refineries, who purchase their own gas or use a third-party to purchase it for them. Noncore customers pay the utility to transport their gas and often take gas directly off the backbone transmission system, bypassing the need to pay for the costs of the distribution system.

These two large customer categories are further subdivided into customer classes with varying rates. A breakdown of average rates by core customer classes is shown for SoCalGas, SDG&E, and PG&E in Figures 33–35.

Core customers pay higher rates than noncore customers because they are more expensive to serve, require greater reliability, and take gas off the distribution system.[228] The fixed costs of serving larger customers are recovered over a larger number of therms due to their higher usage, which results in lower transportation rates per therm. Core bundled service includes a fixed or minimum monthly charge,[229] per-therm

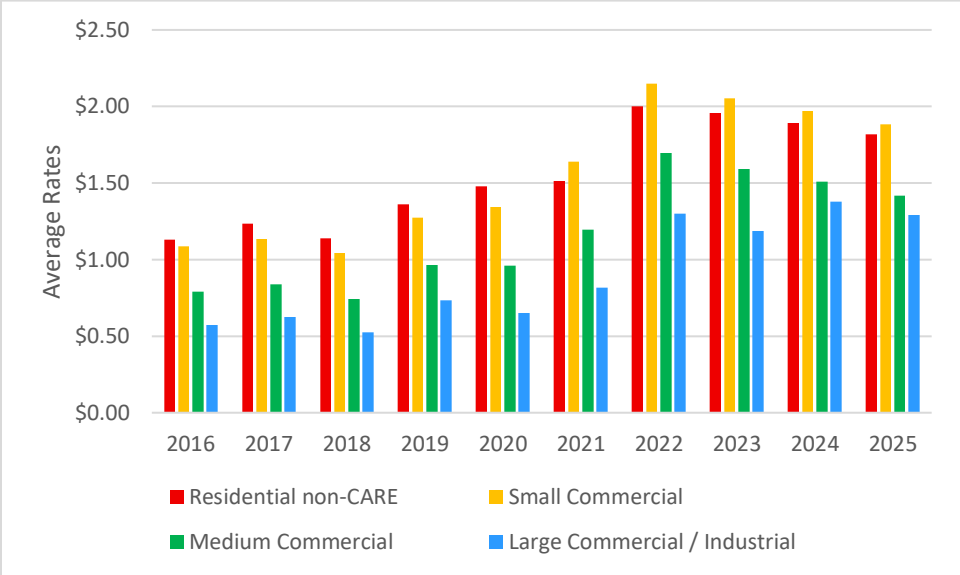
[227] The CARE revenue requirement is collected from non-CARE customers to fund the 20 percent discount provided to CARE customers.

[228] Noncore customer rates include an access charge, a transportation rate (levels often based on volume of service), and the gas PPP surcharge (Electric Generation customers do not pay the gas PPP surcharge).

[229] For residential customers, SoCalGas applies a $5 fixed non-CARE monthly charge and a $4 fixed CARE month charge; SDG&E applies a $4 minimum non-CARE transportation charge and a $3.20 minimum CARE transportation charge; PG&E applies a $4 minimum transportation charge applicable to non-CARE customers only.

procurement and transportation charges, and the PPP surcharge. CARE residential gas customers receive a 20 percent discount on their natural gas bill.

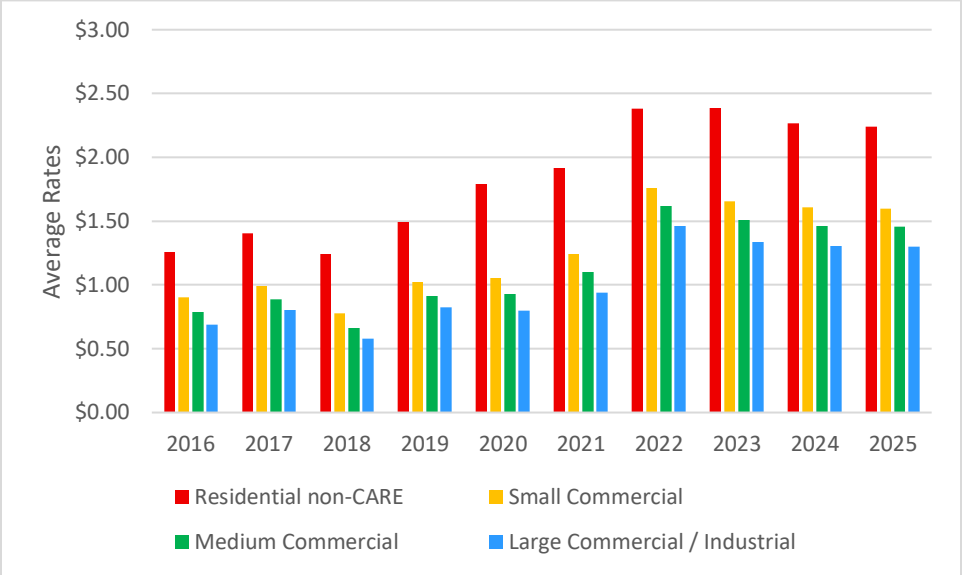
Figure 33: SoCalGas' Average per Therm Rates[230] by Customer Class in Effect January 1 (2016-2025)



SoCalGas' large commercial/industrial customer class has generally experienced upward-treading average rates since 2016. SoCalGas' other customer classes experienced mostly upward-trending average rates from 2016 to 2022, but downward-trending average rates since 2022 due to a decreasing average procurement rate.

[230] Consists of an average transportation rate, procurement rate, and PPP surcharge and taxes. For illustrative purposes, the core procurement rate is applied to SoCalGas' average per-therm rates by customer class. In practice, the gas utilities do not purchase gas supplies for noncore customers.

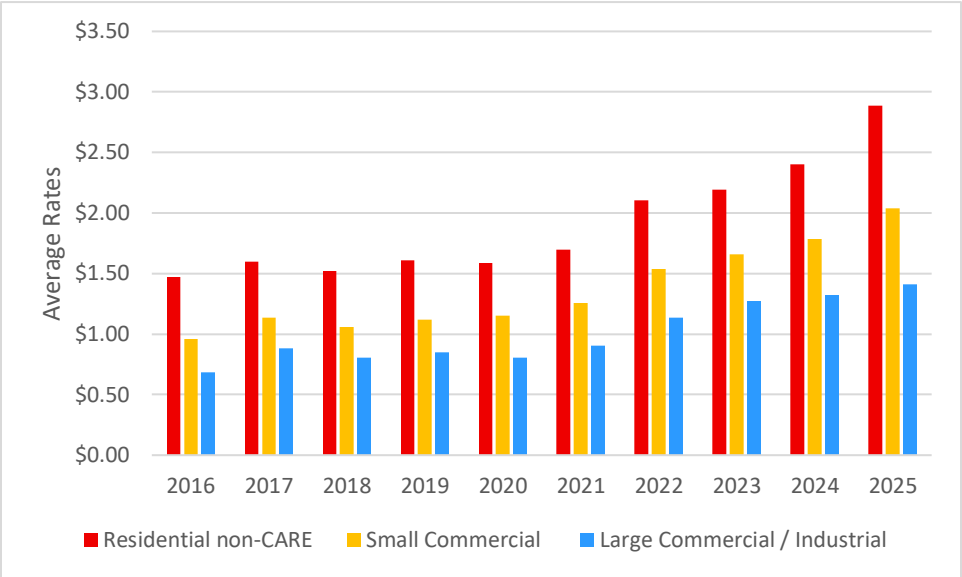
Figure 34: SDG&E's Average per Therm Rates[231] by Customer Class in Effect January 1 (2016-2025)



SDG&E's customer classes experienced mostly upward-trending average rates from 2016 to 2022, but downward-trending average gas rates since 2022 due to a decreasing average procurement rate.

[231] Consists of an average transportation rate, procurement rate, and PPP surcharge and taxes. For illustrative purposes, the core procurement rate is applied to SDG&E's average per-therm rates by customer class. In practice, the gas utilities do not purchase gas supplies for noncore customers.

Figure 35: PG&E' Average per Therm Rates[232] by Customer Class in Effect January 1 (2016-2025)



PG&E's customer classes experienced mostly upward-trending average rates since 2016.

Costs and Rates Containment

The CPUC has undertaken actions in the preceding 12 months (May 1, 2024, to April 30, 2025) and is taking actions in the succeeding 12 months (May 1, 2025, to April 30, 2026) to limit utility costs and rate increases through continued scrutiny of gas utility revenue requirements in various proceedings. This section presents CPUC decisions made in the past 12 months and pending proceedings in which utilities have made requests for cost recovery that could increase rates.

PG&E

Gas Cost Allocation and Rate Design Proceeding

PG&E's 2023 GT&S Cost Allocation and Rate Design (CARD) Application determines cost allocation and rate design for the transmission and the unbundled gas marketplace, including storage. Filed in September 2021, the proceeding addressed PG&E's gas marketplace and sales forecasting for unbundled services for the years 2023-2026.

[232] Consists of an average transportation rate, procurement rate, and PPP surcharge and taxes. For illustrative purposes, the core procurement rate is applied to PG&E's average per-therm rates by customer class. In practice, the gas utilities do not purchase gas supplies for noncore customers.

In Decision 24-03-002 the CPUC approved the All-Party Settlement, without modification, that resolved three broad issues: (1) All-Customer Group Settlement (ACG Settlement), (2) Baja-Redwood Differential Settlement (Baja-Redwood Settlement), and (3) Undisputed Issues Stipulation (Stipulation). Parties agreed on a Local Transmission cost allocation of 65.5 percent for core customers and 34.5 percent for noncore customers, prior to the impact of forecast discounted volumes. Rates implemented pursuant to the decision will recover the GT&S revenue requirement approved in the GRC decision, D.23-11-069.

Gas Procurement Costs Incentives

The Core Procurement Incentive Mechanism (CPIM) provides PG&E with a financial incentive to purchase and transport gas for core ratepayers at a cost that is equal to, or less than, prevailing market prices. The CPIM compares actual monthly purchased gas costs (commodity and transportation) to monthly benchmarks over a 12-month (November to October) period. Cal Advocates' audit of PG&E's 2023 performance report (covering the period November 1, 2020, though October 31, 2021, Year 28) found PG&E's core gas costs and reservation charges were $105.1 million below the CPIM benchmark. Applying the CPIM mechanism, Cal Advocates recommended $94.8 million of the savings go to ratepayers and $10.2 million to shareholders.[233] The Energy Division approved PG&E's advice letter requesting approval of this shareholder reward on October 4, 2024.[234]

SoCalGas and SDG&E

2024 GRC

On December 23, 2024, the CPUC adopted D.24-12-074 authorizing the revenue requirement for SoCalGas and SDG&E service operations for the years 2024 through 2027. The decision adopts a 2024 Test Year revenue requirement of $3.806 billion for SoCalGas, which is $628.7 million lower than the $4.434 billion that SoCalGas requested. The adopted revenue requirement represents an increase of $323.6 million, or a 9.3 percent increase, over the 2023 revenue requirement of $3.482 billion. This resulted in an estimated increase in bills of 3.5 percent for SoCalGas non-CARE residential gas customers in 2024 compared to 2023.[235] For the period 2025 to 2027, while SoCalGas requested a revenue requirement increase of 5.5 to 7.6 percent, the decision adopts a 3 percent annual increase. Overall, SoCalGas requested $19.5 billion in total revenue requirement over the four-year rate case cycle (2024-2027), while the decision reduced it to $16.2 billion, a $3.3 billion reduction.

For SDG&E, the decision adopts a 2024 Test Year revenue requirement of $2.699 billion for combined operations ($2.193 billion for electric and $506 million for natural gas operations), which is $308.3 million lower than the $3.007 billion that SDG&E requested. The adopted combined operations' revenue

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[234] PG&E Advice Letter 4957-G: https://www.pge.com/tariffs/assets/pdf/adviceletter/GAS_4957-G.pdf.

[234] PG&E Advice Letter 4957-G: https://www.pge.com/tariffs/assets/pdf/adviceletter/GAS_4957-G.pdf.

[235] Based on average gas usage of 37 therms per month.

requirement represents an increase of $188.6 million, or a 7.5 percent increase, over the 2023 current combined revenue requirement of $2.510 billion. This resulted in an estimated bill impact of 2.6 percent for SDG&E electric residential customers and 1.8 percent for gas residential customers[236] in 2024 compared to 2023. For the period 2025-2027, SDG&E requested revenue requirement increases of 8.2 to 11.5 percent. For combined electric and natural gas operations, the decision approves an increase of a 3 percent annual increase plus 1 percent additional capital exceptions for wildfire mitigation work. Overall, SDG&E requested $14.03 billion in total revenue requirement over the four-year rate case cycle (2024-2027) for gas and electric combined. The decision reduced it by $2.43 billion to $11.6 billion.

Gas Cost Incentives

The Gas Cost Incentive Mechanism (GCIM) provides SoCalGas with a financial incentive to purchase and transport gas for SoCalGas and SDG&E core ratepayers at a cost that is equal to, or less than, prevailing market prices. The GCIM compares actual monthly purchased gas costs (commodity and transportation) to monthly benchmarks over a 12-month (April to March) period.

SoCalGas's 2023 GCIM application claimed $417.6 million in core procurement cost savings below the benchmark (for the period April 1, 2022-March 31, 2023, Year 29). Using the standard GCIM calculation would have resulted in a ratepayer benefit of $354.8 million in lower gas costs and a shareholder reward of $62.8 million. Ultimately, the CPUC approved a shareholder reward of $22.7 million in, D.24-10-007,[237] resulting in ratepayer savings of $395.0 million.

On June 17, 2024, SoCalGas filed A.24-06-005 for GCIM Year 30, covering April 1, 2023, through March 31, 2024. Cal Advocates issued its Monitoring and Evaluation report on January 17, 2025,[238] acknowledging SoCalGas's recorded gas costs of $74.3 million below the benchmark, resulting in ratepayer savings of $60.4 million and a calculated shareholder reward of $13.9 million that is pending approval by the CPUC.

Cost Allocation Proceeding

For SoCalGas and SDG&E, the Cost Allocation Proceeding (CAP) is the second phase of a GRC where costs approved in the GRC proceeding are allocated among the various customer classes to determine their respective rates.

These utilities filed the application on September 30, 2022, to revise rates for gas services and to implement gas storage related proposals effective January 1, 2024, through December 31, 2027. SoCalGas and SDG&E also propose to move the CAP from a three-year to a four-year cycle to match the cycle now used for the GRC.

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[236] Based on average gas usage of 25 therms per month.

[237] D.24-10-007: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M544/K267/544267180.PDF.

[238] Cal Advocates Year 30 GCIM Monitoring and Evaluation Report: Microsoft Word - A2406005 Public Advocates Office Monitoring and Evaluation Report on SoCalGas Application - CA-01 crk 011725.

The CAP proposes an allocation of costs of providing natural gas service among core and noncore customer classes. The CAP also proposes gas storage-related changes for managing the reliability of the natural gas system operated by SoCalGas on behalf of both SoCalGas and SDG&E. This includes proposals for storage capacity functions and allocations considering factors such as reduced capacities at storage fields, planned and unplanned transmission pipeline outages, impacts of weather, and the availability of intrastate and interstate gas supply for reliably serving customers.

In D.24-07-009, the CPUC approved a settlement resolving a majority of disputed issues between parties. For SoCalGas in 2024, Transmission costs of $601.317million (with FFU) were split into Backbone Transmission ($410.135 million) and Local Transmission ($191.182 million). Storage Costs of $330.849 million were allocated to Injection services (38.1 percent), Withdrawal (36.3 percent), and Inventory (25.6 percent). For SDG&E, Backbone Transmission costs were $75.347 million. D.24-07-009 also denied two other settlements addressing the Fixed Customer Charge and Hydrogen Refueling.

Aliso Canyon Order Instituting Investigation

On February 9, 2017, the CPUC opened the Aliso Canyon proceeding, Investigation (I.) 17-02-002, as directed by SB 380 (Pavley, 2016). SB 380 required the CPUC to "determine the feasibility of minimizing or eliminating the use of the SoCalGas Aliso Canyon Natural Gas Storage Facility (Aliso Canyon) while still maintaining energy and electric reliability for the region."

On December 19, 2024, the CPUC approved D.24-12-076 and closed the proceeding. While the Decision finds that the Aliso Canyon facility is currently necessary for natural gas and electric reliability and cost containment, it also creates a pathway to reassess the need for the facility as demand for natural gas declines.

The Decision establishes a natural gas peak day demand target, which is the level at which Southern California peak day gas demand can be served without Aliso Canyon. As demand declines toward that target, the CPUC may incrementally reduce the maximum inventory allowed at Aliso Canyon. A proceeding to consider closure of Aliso Canyon will open when: 1) forecasted peak day demand for two years in the future decreases to the target level and 2) a staff assessment shows that Aliso Canyon could be closed without jeopardizing reliability or just and reasonable rates.

Customer choice in pursuing building decarbonization can play a role in determining how fast Southern California reaches the target level, since residents and small businesses make up the majority of demand on peak winter days. While natural gas demand is on a downward trajectory[239] due to California's climate policies, gas demand for homes and small businesses has increased in Southern California since the leak.[240]

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[239] EIA, *California Natural Gas Consumption by End Use*, 2025. *See* https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SCA_a.htm.

[240] CPUC, *CPUC Sets Concrete Path to Consider Reducing and Eliminating Reliance on Aliso Canyon Natural Gas Storage Facility*, December 19, 2024. *See* https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-and-enforcement-division/documents/fact-sheets/ac-fact-sheet-121924.pdf. Joint gas utilities, 2024 California Gas Report, p. 162, for 2019-2023 data. *See* https://www.socalgas.com/sites/default/files/2024-08/2024-California-Gas-Report-Final.pdf. Joint gas utilities, 2022 California Gas Report, p. 184, for 2017-2019 data. *See* https://www.socalgas.com/sites/default/files/Joint_Utility_Biennial_Comprehensive_California_Gas_Report_2022.pdf.

There are currently over a dozen building decarbonization programs available to customers in Southern California that provide different types of incentives for customers to replace natural gas appliances with electric ones.

All Investor-Owned Utilities

Long-Term Gas Planning Rulemaking

The CPUC is developing long-term gas planning and related procedures to ensure safe, reliable, and affordable service as natural gas consumption declines in response to California's climate policies. In 2024, the CPUC opened a new rulemaking[241] to consider ongoing gas transition issues.[242] The new rulemaking seeks to develop and implement long-term gas transition planning approaches to help inform and operationalize the gas transition and to identify opportunities to reduce system and ratepayer costs and facilitate decarbonization in the near-term.

In November 2024, the CPUC issued questions to the parties on potential interim actions, including potential changes to rate calculation methods and non-pipeline alternatives that are cheaper than traditional gas expenditures. Reducing gas demand does not automatically reduce the cost of gas infrastructure because customers require gas connections as long as they have any demand. If utility infrastructure costs remain constant as demand declines, rates per therm increase. Achieving cost containment in an era of declining fossil gas use will require strategic planning to reduce the need for and cost to maintain gas infrastructure.

The rulemaking is also implementing the mapping requirements of SB 1221 (Min 2024). SB 1221 creates several new requirements related to the establishment of priority neighborhood decarbonization zones, including that gas utilities provide maps of their foreseeable gas distribution line replacement projects and other information. Designing decarbonization projects to avoid planned gas infrastructure upgrade costs holds the potential to reduce utility ratepayer costs.

In 2022, the previous long-term gas planning rulemaking adopted General Order 177, which requires utilities to report annually on their plans for large gas infrastructure investments 10 years out and on costs and non-pipeline alternatives for projects five years out.[243] Following workshops on these plans in 2025, parties will provide comments and utilities may propose changes to the general order.[244]

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[241] *See* R.24-09-012.

[242] *See 2024 Joint Agency Staff Paper: Progress Towards a Gas Transition. See* https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M526/K067/526067752.PDF.

[243] General Order 177. *See* https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M499/K705/499705854.PDF. Adopted in D.22-12-021, *see* next footnote.

[244] D. 22-12-021. *See* https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M499/K705/499705675.PDF.

High Gas and Electric Prices Investigation

The CPUC's Investigation (I.) 23-03-009 continues fact-gathering efforts on the causes of the extraordinarily high gas prices in the winter of 2022-2023. Energy Division Staff issued its first White Paper in this investigation in July 2024 and a version updated to incorporate party comments on February 10, 2025,[245] followed by a second White Paper on June 5, 2025.[246]

White Paper I found that key causes of the high winter 2022-2023 natural gas prices included pipeline constraints, reduced gas flows, cold weather, and low storage levels. U.S. liquified natural gas (LNG) exports increased due to geopolitical shifts, while pipeline outages and noncore customer storage decisions worsened supply issues. The White Paper I also included analysis of the differences between PG&E and SoCalGas' gas commodity purchasing decisions. It found that the PG&E citygate market was more liquid than the SoCalGas citygate market all winter and that PG&E relied more heavily on spot market purchases in January 2023. In contrast, SoCalGas faced greater exposure to pipeline constraints and relied more heavily on monthly contracts in January 2023 than PG&E. These differences in circumstance and strategy played a significant role in the variations of their gas purchasing costs during the winter of 2022-2023.

Part II of the White Paper mailed on June 5, 2025 for party comment. The second White Paper examined storage injections and withdrawals in more detail, looked into the role of independent gas storage providers, and analyzed the impact of high gas prices on electric prices. A third White Paper on gas procurement incentive mechanisms and hedging is expected in 2025. The proceeding is ongoing.

Dairy Biomethane Pilot Projects

Pursuant to SB 1383 (Lara, 2016), the CPUC opened a rulemaking[247] to establish dairy biomethane natural gas pipeline injection demonstration projects. In 2018, the CPUC along with the Air Resources Board and the Department of Food and Agriculture, put forth a pilot solicitation and selected six projects for construction. Contracts between utilities and developers of the six pilot projects were signed, and the new dairy biomethane facilities started converting biogas from dairy digesters into renewable natural gas (RNG) for heating and transportation purposes in an effort to move California closer to its goal of reducing methane emissions by 40 percent below 2013 levels by 2030. The pilots will undergo evaluation processes to determine GHG reduction levels and project goal attainment. Forecasted costs associated with the six pilot projects are estimated to be approximately $133 million, and utilities are required to seek prior authorization from the CPUC for any deviation from the original cost estimates. Due to delays experienced as a result of the COVID-19 pandemic, the first of these projects was adjusted to come online in 2021 and the last of these projects was anticipated to come online in the third quarter of 2023. As of March 2025, five out of the

[245] *High Natural Gas Prices in Winter 2022-23: Part I*: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M556/K897/556897251.PDF.

[246] *High Natural Gas Prices in Winter 2022-23: Part II*: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M567/K955/567955443.PDF.

[247] *See* R.17-06-015.

six dairy pilots are operational and only one of the six projects–JG Weststeyn–failed to reach operational status.

PG&E initiated A.23-04-005 in April of 2023 to consider approval of cost overruns specific to the Merced California Energy Exchange (CEE) project developed by Maas Energy Works, Inc. (MEW). On October 17, 2024, the CPUC approved $4,848,720 of the $8,517,000 requested by PG&E in cost overruns above the bid amount of $10,183,855 to recover in rates and allowed PG&E to reimburse MEW in D.24-10-004. The authorized amount of $4,848,720 represents approximately 57 percent of MEW's requested overage of $8,517,000. Similar cost overruns were reported separately by SoCalGas for four dairy biomethane pilot projects: (1) CalBioGas Buttonwillow LLC, (2) CalBioGas North Visalia LLC, (3) CalBioGas South Tulare LLC, and (4) Lakeside Pipeline LLC. Sempra sought to recover costs for the four projects through its latest General Rate Case. The CPUC rejected this proposal and instead ordered SEMPRA to file reasonableness review applications for their dairy pilots cost overruns.

Biomethane Procurement Considerations (SB 1440 Implementation)

In response to SB 1440 (Hueso, 2018), on February 24, 2022, the CPUC adopted a biomethane procurement standard in D.22-02-025. The decision established biomethane procurement targets crafted to help achieve the state's goals for 40 percent reduction in methane and other Short-Lived Climate Pollutants by 2030. Biomethane procurement will reduce otherwise uncontrolled methane and black carbon emissions in California's waste, landfill, agricultural, and forest management sectors. The short-term 2025 biomethane procurement target is 17.6 billion cubic feet of biomethane, which corresponds to 8 million tons of organic waste diverted annually from landfills, in part to support requirements imposed on CalRecycle pursuant to implementation of SB 1383 (Lara, 2016). Each utility will be responsible for procuring a percentage of the total biomethane procurement obligation in accordance with its proportionate share of natural gas deliveries. The medium-term 2030 target is a Renewable Gas Standard (RGS) that requires biomethane procurement at 12.2 percent of current residential and small business (i.e., "core") gas usage in 2020, which equates to 72.8 billion cubic feet per year for California's four largest gas IOUs, collectively.

Various other requirements in the procurement program are designed for environmental and social justice, public safety, and methane leak reduction. D.22-02-025 required the IOUs to submit a standard biomethane procurement methodology to establish a consistent bid scoring criteria for procurement solicitations, which was approved by the CPUC in late 2022. D.22-02-025 also required the gas IOUs to submit Renewable Gas Procurement Plans for the CPUC to vet program adherence to decision language. PG&E, SoCalGas, SDG&E, and Southwest Gas filed their respective plans on December 28, 2022.

The CPUC issued a ruling on July 20, 2023, requesting estimated program procurement costs and proposed program cost caps from the gas IOUs to help determine potential program impacts and enhance ratepayer protections. Another ruling was issued on June 10, 2024, to inform the review of the pending Renewable Gas Procurement Plans and work toward identifying improvements to the Renewable Gas Standard program structure. A proposed decision recommending adoption of some version of the procurement plans

is expected sometime before the end of 2025. In the meantime, procurement solicitations from all of the large gas IOUs are ongoing, as directed by D.22-02-025.[248]

Line Extension Subsidy Phase-outs for Mixed-Fuel New Construction in Phase III of Building Decarbonization Proceeding

Following the elimination of gas line extension subsidies by D.22-09-026, a subsequent staff report recommended eliminating electric line extension subsidies for mixed-fuel new construction (i.e., new construction that using both electricity and gas and/propane as a fuel source instead of electricity alone). The staff report estimated annual electric ratepayer savings potentially as high as $486,524,443 if mixed-fuel new construction stayed at 2022 levels.[249] In D.23-12-037 the CPUC adopted staff's recommendations with minor modifications, meaning electric line extension subsidies no longer available for new mixed-fuel building projects as of July 1, 2024, unless a project is otherwise exempted.[250]

IOU Perspectives on Gas Rate Containment

The following represents IOUs' perspectives on gas rate containment, as reported to the CPUC. [251] Sempra states that an appropriately set monthly fixed charge would allocate a fair share of fixed costs to customers who choose to partially electrify (e.g., appliance electrification) their home, but who maintain their gas service at lower consumption levels. PG&E did not provide specific ideas on gas rate containment as its comments were entirely electric-focused.

Non-CPUC Regulations that Impact Rates

CalGem Storage Regulations

In the aftermath of the 2015 Aliso Canyon gas leak, CalGEM developed more stringent regulations for California's natural gas storage fields that went into effect October 1, 2018. These regulations require that all gas storage wells be converted to tubing-only flow within seven years and that storage providers conduct mechanical integrity and pressure testing on each well every 24 months unless a different testing schedule is proposed by the storage provider and approved by CalGEM.

There are significant costs associated with the work that the gas utilities must undertake to adhere to these regulations, including well construction requirements, additional inspections and surveys, integrity testing,

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[248] D.22-02-025 Ordering Paragraph 28.

[249] R.19-01-011 Phase 3B Staff Proposal.

[250] Mixed-fuel building projects with electric line extensions that were under contract with the IOU and fully paid for prior to July 1, 2024 can still receive subsidies so long as project energization is completed prior to July 1, 2025.

[251] From the IOUs' reports to limit cost and rate increases. Full IOU reports available here; *See* "2025 Electric and Gas Costs Utility Reports" bullet point under "Reports and White Papers" section of the webpage. Inclusion of IOU report elements in this report does not imply CPUC endorsement.

and continuous well monitoring. In addition, complying with the CalGEM rules also decreases storage injection and withdrawal capacity for two reasons: 1) wells are out of service during testing; and 2) less gas can be injected and withdrawn from each well using tubing-only flow. Reduced withdrawal capacity can also increase costs and may have market impacts. For example, in its last General Rate Case, PG&E received approval to drill 12 additional wells at a cost of $98 million to compensate for reduced withdrawal capacity.

PHMSA Mega Rule

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is an agency within the U.S. Department of Transportation that oversees the nation's pipeline and hazardous materials transportation infrastructure. Two major gas pipeline incidents caused PHMSA to issue a Notice of Proposed Rulemaking in April 2016 to clarify and enhance rules for the safe transportation of gas and hazardous liquids.[252] The 2010 San Bruno, California pipeline rupture revealed the dangers of "grandfather" clauses that did not require older transmission pipelines to meet modern testing standards.[253] The 2012 rupture of a pipeline near a highway in Sissonville, West Virginia demonstrated the limitations of the definition of High Consequence Areas (HCAs),[254] which did not include proximity to major roadways. PHMSA divided the rulemaking into three phases, issuing new rules in 2019,[255] 2021,[256] and 2022.[257] Together, these rules are often referred to as the PHMSA Mega Rule.

The final rule in the first phase was issued on October 1, 2019. It mandates that gas operators begin implementing the new procedures on July 1, 2021. The primary requirements of the new rule are that pipeline operators must 1) reconfirm the maximum allowable operating pressure (MAOP) of certain transmission pipelines by 2035, 2) verify pipeline material properties and attributes, and 3) identify and conduct inline inspections of "piggable" transmission pipelines in Moderate Consequence Areas (MCAs) by 2034 and reassess them every 10 years thereafter.[258] Previously, pipeline operators were only required to do inline inspections in High Consequence Areas.

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[252] Docket No. PHMSA-2011-0023: https://www.federalregister.gov/documents/2016/04/08/2016-06382/pipeline-safety-safety-of-gas-transmission-and-gathering-pipelines.

[253] Part 192 § 192.619(c) allowed pipeline operators to establish the Maximum Allowable Operating Pressure (MAOP) based upon the historical highest actual operating pressure records obtained during the five-year interval between July 1, 1965, to July 1, 1970, rather than using engineering design basis (design, material specification, construction, and testing) to establish the MAOP. Most of the pipeline operators that used the grandfather clause lacked either a post-construction hydrotest records and/or did not have pipe material property records.

[254] High consequence areas are "those segments of their pipeline systems that pose the greatest risk to human life, property, and the environment." Pipeline operators are required to take extra precautions in HCAs. Federal Register: Pipeline Safety: High Consequence Area Identification Methods for Gas Transmission Pipelines.

[255] 2019 gas transmission rule: https://www.federalregister.gov/documents/2019/10/01/2019-20306/pipeline-safety-safety-of-gas-transmission-pipelines-maop-reconfirmation-expansion-of-assessment.

[256] 2021 final rule: https://www.federalregister.gov/documents/2016/04/08/2016-06382/pipeline-safety-safety-of-gas-transmission-and-gathering-pipelines.

[257] 2022 final rule: https://www.federalregister.gov/documents/2022/08/24/2022-17031/pipeline-safety-safety-of-gas-transmission-pipelines-repair-criteria-integrity-management.

[258] In-line inspections are conducted using a tool that is inserted in the pipeline and conducts tests as it moves through the line. These tools are also known as "smart pigs." A pipeline is "piggable" if it is large enough to accommodate a pig and doesn't have any impediments such as sharp curves where the pig could get stuck.

Reconfirming MAOP

The Mega Rule states that MAOP must be reconfirmed for transmission lines in High Consequence Areas and Class 3 and 4 locations and piggable transmission lines in Moderate Consequence Areas that do not have verifiable records that they have met the modern standard.[259] Operators must reconfirm 50 percent of pipeline mileage by July 3, 2028, and 100 percent by July 2, 2035. The following methods can be used to reconfirm MAOP: pressure test; pressure reduction; Engineering Critical Assessment (ECA) using in-line inspection (ILI or pigging) tools; pipeline replacement; small Potential Impact Radius (PIR) pressure reduction; or other technology.

Verifying Pipeline Materials

Pipeline operators must document pipelines' physical characteristics and attributes, including diameter, wall thickness, seam type, and grade. These documents must be traceable, verifiable, complete, and maintained for the life of the pipeline. If an operator does not have complete records, it must develop and implement procedures for conducting assessments to verify pipeline properties. Where possible, these tests should be conducted when pipeline excavations occur during the normal course of business.

Assessment Outside High Consequence Areas

The Mega Rule requires integrity assessment of non-HCA pipelines in Class 3 or 4 locations and MCAs by 2034 and every 10 years thereafter. These integrity assessments must be capable of identifying anomalies and defects associated with the threats to which the pipeline is susceptible and be performed using one or more of the following methods: in-line assessment; pressure test; spike hydrostatic test; direct examination; guided wave ultrasonic testing; direct assessment; or other proven technology.

Comparison of Mega Rule and PSEP

Both the Mega Rule and PSEP both have origins in the San Bruno pipeline explosion and other pipeline explosions nationwide and seek to improve transmission pipeline safety, but they are not identical. The Mega Rule requires California utilities to make additional expenditures on pipeline safety beyond what they have made, or plan to make, on PSEP. Aligning the statutory requirements of PSEP with the federal Mega Rule has the potential to meet safety goals while saving money for California ratepayers. The table below provides a comparison of the two programs.

Table 18: Mega Rule vs. PSEP

[259] Class locations range from one to four and specify the number and type of buildings and facilities near a transmission pipeline. Higher classes indicate denser environments and require stricter testing protocols.

	Mega Rule	PSEP
MAOP Reconfirmation Required	Transmission lines operating at 30% SMYS and above without verifiable records	All transmission lines without record of post-construction pressure test
MAOP Reconfirmation Methods Allowed	Various, listed above	Pressure test or replace
Verification of Pipeline Materials and Properties?	Yes	No
Assessment in MCAs?	Yes	No
Requires Installation of Automatic and/or Remote Shut-off Valves?	No[260]	Yes
Requires Replacement Pipeline to Be Piggable?	No	Yes

PG&E, SoCalGas, and SDG&E provided updated estimates of the miles of pipeline that would be impacted by Phase 1 of the Mega Rule to the CPUC's Safety and Enforcement Division (SED). PG&E specified that these figures do not include work already completed.

[260] PHMSA released a new rule mandating the installation of remote control and/or automatic shut-off valves on newly constructed or entirely replaced pipelines that are six inches in diameter or greater on March 31, 2022.

Table 19: Miles of Pipeline Subject to PHMSA Mega Rule

	PG&E	SoCalGas	SDG&E
MAOP Reconfirmation	30	374	46
Materials Verification	10	405.9	31.4
Assessment Outside HCA	372.64	240.19	3.95

Source: Data request responses from PG&E and SoCalGas.

Mega Rule costs are embedded in the utilities' costs for their Transmission Integrity Management and Gas Safety Enhancement Programs.

CARB GHG Regulations

The Global Warming Solutions Act of 2006 (AB 32) charged CARB with creating a market-based mechanism to achieve the legislative goal of limiting California's greenhouse gas (GHG) emissions to 1990 levels by 2020 (later expanded in AB 398 and SB 32 to a GHG emissions target of 40 percent below 1990 levels by 2030).

Following AB 32, CARB promulgated regulations creating the Cap-and-Trade Program. Under CARB's regulations, large emitters of greenhouse gases must purchase and surrender compliance instruments (typically allowances or offsets) to CARB for each ton of GHG released. This includes electric and natural gas utilities, who must pay for GHG emissions that come from burning fuel for electricity generation or that occur when customers burn purchased fuel. Electric utilities began accruing Cap-and-Trade Program costs January 1, 2013, and 100 percent of GHG costs were incorporated into electric rates starting on January 1, 2014. Natural gas utilities began accruing Cap-and-Trade Program costs January 1, 2015 but costs were not introduced into rates until July 1, 2018. In 2024, natural gas utilities incorporated 70 percent of the GHG costs into rates; 100 percent of GHG costs must be fully incorporated into rates by 2030. GHG costs not incorporated into natural gas rates have been paid for by reducing the natural gas Climate Credit.

Similar to other procurement costs, Cap-and-Trade Program costs are passed on to customers in rates. For most California electric IOU customers, Cap-and-Trade Program costs are included in rates as part of generation costs. For natural gas IOU customers, Cap-and-Trade Program costs are included in rates as part of the transportation cost. Each year, the CPUC reviews and approves electric Cap-and-Trade Program costs as part of the annual Energy Resource Recovery Account (ERRA) or Energy Clause Adjustment Account (ECAC) Forecast Application and natural gas Cap-and-Trade Program costs as part of the annual end of year true-up advice letter process.

CARB also allocates some allowances for free to electric and natural gas utilities on behalf of their ratepayers. Electric IOUs are required to sell these allowances at auction each year and utilize the proceeds for the benefit of ratepayers. Natural gas IOUs may also use some allowances for compliance, reducing the

cost passed to customers in rates. Since 2014 (for electric customers) and 2018 (for most natural gas customers) residential customers have received the California Climate Credit as their share of the proceeds from the sale of allocated allowances. Although not part of rates, the California Climate Credit is delivered on-bill automatically to all residential ratepayers, including submetered customers and community choice aggregator (CCA) customers within the footprint of an IOU. For the decade 2014-2024, as a result of the Cap-and-Trade Program, the average residential electric customer received around $850 in California Climate Credits, while the average residential natural gas customer has received around $275.

Non-residential customers also pay Cap-and-Trade costs in rates. For electric customers, Public Utilities Code Section 748.5 requires that small business and emission-intensive trade-exposed industrial customers also receive a portion of the CARB allocated allowance proceeds. Small Business customers automatically receive the on-bill Small Business California Climate Credit, while qualifying industrial customers receive the California Industry Assistance Credit. For the decade 2014-2024, the assistance to small business customers has totaled $816 million while the California Industry Assistance Credit has totaled $811 million statewide. Natural gas non-residential customers do not receive on-bill assistance.

In total for the decade 2014-2024, California electric IOU customers (residential, small business, and industrial) have received over $11 billion in automatic electric on-bill assistance and California natural gas IOU residential customers have received over $3.5 billion in automatic on-bill assistance.

Appendices

Appendix A – 2025 Electric and Gas Utility Reports on Actions to Limit Cost and Rate Increases

The following weblink to the CPUC's Energy Division Retail Rates webpage contains links to the 2025 electric and gas utility reports submitted by PG&E, SCE, SDG&E, and SoCalGas, pursuant to Public Utilities Code Section 913.1: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-rates. See "2025 Electric and Gas Costs Utility Reports" bullet point under "Reports and White Papers" section of the webpage.

Appendix B – A Lexicon of Key Ratemaking Terms and Definitions

The following is a list of essential definitions used in this document and in the CPUC's rate-setting work in GRC Phase I, GRC Phase II proceedings, and other rate-setting proceedings:

- **Attrition Year:** In GRC proceedings, a year subsequent to the test year for which formulaic adjustments to the test year revenue requirement are made until the next GRC cycle commences.
- **Bundled Customers:** Customers who get all of their services - generation, transmission, and distribution services - from the Investor-Owned Utilities.
- **Bundled System Average Rate (Bundled SAR):** Bundled authorized revenue requirement divided by bundled forecasted kilowatt-hour sales.
- **Bundled Residential Average Rate (Bundled RAR):** Bundled residential class authorized revenue requirement divided by bundled residential forecasted kilowatt-hour sales.
- **Cost-of-Service (COS) Regulation:** A form of rate regulation where a regulated entity will be allowed to collect in rates its total cost of providing services plus a reasonable profit.
- **Demand Response (DR):** The reduction by end-use customers of electricity usage during peak periods (or shifting of usage to another time period), in response to a price signal, financial incentive, environmental condition, or reliability signal.
- **Depreciation:** Capital investments in facilities and assets are initially financed by the utilities' own funding sources and are returned to the utilities with ratepayer funding in the form of depreciation expense. Depreciation spreads the ratepayers' cost of the physical electric plant and systems over its useful life.
- **Distributed Energy Resources (DER):** Distribution-connected generation resources, including energy efficiency, storage, electric vehicles, and demand response technologies.
- **Energy Burden:** Actual home energy costs as a percentage of household income.

- **Energy Resource Recovery Account (ERRA):** ERRA balancing accounts are evaluated in annual proceedings and track authorized versus actual utility energy procurement costs e.g., fuel and purchased power. ERRA costs are pass-through expenses; the utility receives no mark up or profit on these costs.
- **Fixed Charge:** A charge assessed on customer bills to recover fixed costs.
- **Fixed Cost:** A cost that does not change as the quantity consumed (and produced) changes during some defined time increment. A utility's fixed costs may be difficult to allocate because some costs are customer-specific and some are systemwide.
- **General Rate Case (GRC):** A proceeding in which revenue requirements are approved based on the costs of operating and maintaining the utility system. GRCs are often "settled" based on overall agreement between advocacy groups and the utility, with the CPUC approving the settlement agreement if it is "reasonable in light of the whole record, consistent with the law, and in the public interest…"
- **Grid Services:** The utility's cost of providing grid services consists of the typical fixed costs associated with: (1) transmission, (2) distribution, (3) generation capacity, and (4) ancillary and balancing services that the grid provides throughout the day.
- **Load Serving Entities (LSE):** A company or organization that supplies load (electricity) to customers. For CPUC-jurisdictional LSEs, these are defined as Investor-Owned Utilities (IOU), Community Choice Aggregators (CCA), and Direct Access (DA) suppliers.
- **Non-Bypassable Charges (NBC):** Costs of public purpose programs (PPP) and certain other programs or costs that are paid by all customers who use the utility delivery system.
- **Non-Wires Alternatives (NWA):** Non-traditional solutions, such as DERs, which replace or defer traditional transmission and distribution investments, such as poles, wires, and transformers.
- **Power Charge Indifference Adjustment (PCIA):** A rate component intended to equalize cost sharing between departed load and bundled load.
- **Rate Base:** The book value, after depreciation, of the generation, distribution, and transmission infrastructure assets owned and operated by the utility for which they may earn a profit. Other things being equal, a larger rate base results in higher net income for utilities.
- **Rate Component**: The specific part of a utility rate corresponding to a functional area of utility operations (i.e., generation, distribution, transmission, etc.).
- **Rate of Return (ROR) on Rate Base:** The cost of paying back utility debtholders with interest, plus the Return on Equity (ROE) to shareholders, as a weighted average of all types of capital.
- **Return on Equity (ROE):** Return to utility shareholders, or profit, and the most controversial component of the ROR formula.
- **Rate Design:** Designing rate schedules and further allocating revenues to individual customers within a customer class. Rate design is also used to promote conservation or other desired outcomes.
- **Revenue Requirement or Utility Costs:** Total operating costs, depreciation, and a reasonable profit, as recovered in rates.

- **Revenue Allocation:** Allocating total revenue requirement to individual customer classes (residential, commercial, agricultural, industrial) based on the utility's cost to serve that class.
- **System-Level Revenue Requirement**: Includes the revenue requirement for all customer classes and all bundled and unbundled customers i.e., it is the total revenue requirement that the IOU collects.
- **Test Year:** In GRC proceedings, the first year of the GRC cycle for which the CPUC sets a pre-specified revenue requirement.
- **Time-of-Use (TOU) Rate Plan**: TOU rate plans are based on when and how much energy is used. TOU rates are lower during the day, when less expensive renewable energy sources like solar and wind are available.
- **Total Revenue Requirement:** Rate Base x Authorized Rate of Return + Expenses.
- **Total System Average Rate:** Total authorized revenue requirement divided by total forecasted kilowatt-hour sales.
- **Unbundled Customers**: Customers who take distribution and transmission service only, with generation service provided by a separate entity, usually a Community Choice Aggregator (CCA) or Direct Access (DA) service provider.
- **Utility Decoupling:** Decoupling refers to annual rate-making adjustments that ensure that utility revenues are separate and independent of actual kWh sales between rate cases, thus removing the disincentive for utilities to encourage energy conservation.