

2026 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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California Public Utilities Commission

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Cover Photo: Conceptual Representation of the Clean Energy Transition

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I. Executive Summary

The California Public Utilities Commission (CPUC) issues this 2026 Senate Bill (SB) 695 Report pursuant to Public Utilities Code Section 913.1. The large electric and natural gas Investor-Owned Utilities (IOU) that fall under the reporting requirements of Public Utilities Code Section 913.1 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).[1] The same statute requires the IOUs to propose measures to control costs and rate increases.[2] This report outlines primary cost drivers of IOU electric rates and cost containment actions that are underway.[3]

The CPUC's mission is to ensure that California IOU customers receive safe, reliable, and clean utility service at just and reasonable rates. Electric rates reflect policy choices and investments made to provide electric service to Californians. 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.

Starting in 2021, bundled[4] system average rate (SAR) increases began to outpace inflation for the three large electric IOUs. Between January 2017 and January 2026, electric bundled residential average rate (RAR) increased by an average of approximately 8 percent, 10 percent, and 8 percent per year for PG&E, SCE, and SDG&E, respectively, compared to an inflation rate of 3.6 percent over the same period. In 2026, all three IOUs' bundled SARs remained substantially higher than the assumed rate of inflation.

This report finds that there are two primary cost drivers for the increases in electric rates: 1) wildfire related investments costs and 2) subsidies for rooftop solar. Over the last ten years, these costs have become increasingly visible on customer bills. Subsidies for rooftop solar account for between 12 and 20 percent of the monthly bill of residential customers without rooftop solar, depending on the IOU. Wildfire-related revenue requirements account for between 10 and 14 percent of residential customers' monthly electricity bills, depending on the IOU. Together, these two cost drivers represent between 25 and 30 percent, or $45 to $60 of the monthly bill of residential customers without rooftop solar, depending on the IOU.

PG&E, SCE and SDG&E collected approximately $37 billion from customers in authorized revenue requirement related to wildfire costs from 2020 through the end of 2025. In the last two years, electric rates for PG&E and SCE customers have remained relatively stable compared to the significant increases

[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 Section 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.

[3] Public Utilities Code Section 913.1(a) requires the CPUC to publish recommendations that can be undertaken over the succeeding 12 months to limit California IOU cost and rate increases consistent with the state's energy and environmental goals.

[4] Bundled IOU customers take all services–generation, transmission, and distribution services–from the IOU; unbundled customers take transmission and distribution services from the IOU, with generation service provided by a separate load serving entity.

observed between 2021-2024. This may be a result of those electric utilities fully recovering certain approved wildfire-related costs. However, new wildfire-related revenue requirements may be added as pending proceedings conclude.

In regard to solar subsidies, customers without rooftop solar currently pay an estimated $8.3 billion each year to subsidize customers with rooftop solar. Under current rules, the size of this subsidy is largely determined by the shared electricity costs of the grid that rooftop solar customers avoid paying, and the overpayments Net Energy Metering (NEM) customers receive for the exported energy they send to the grid.

While rooftop solar subsidies and wildfire-related costs are the primary cost drivers, there are other drivers of costs that continue to be monitored: 1) non-wildfire related transmission and distribution upgrades, and 2) generation costs for bundled customers. Transmission and distribution rates corresponding to revenue requirement for power lines, poles, transformers, and repair crews, whether for replacement or new infrastructure, have almost doubled since 2017. The IOUs estimate that the cost of upgrading the primary and secondary distribution grid to meet electrification needs through 2040 will grow over time to accommodate new sources of demand such as electric vehicles, data centers, and building electrification. However, as load growth increases over time, there is potential for downward pressure on electric rates as fixed costs can be spread over more kilowatt-hour sales.

While generation costs to serve bundled customers have grown faster than inflation over the past decade, they have decreased since 2023-2024, when capacity was limited, which drove up California Independent System Operator (CAISO) market prices. Recent decreases are due to new capacity coming online and mild weather years. However, generation rates could increase in the future if California experiences weather years that are less mild and load growth outpaces new generation coming online.

Regarding trends in natural gas system revenue requirements, the combined 2026 gas revenue requirement of California's three largest gas utilities[5] has increased by 74 percent since 2016. The combined revenue requirements support the operation of seven gas storage facilities and approximately 10,000 miles of large diameter, high pressure gas transmission pipelines, which connect to approximately 105,000 miles of smaller diameter, lower pressure gas distribution pipelines serving approximately 11.6 million natural gas meters.[6]

Cost containment is critical for both the natural gas and electric system revenue requirements. The CPUC requires the large IOUs to file a general rate case (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 CPUC 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

[5] PG&E, SDG&E, and SoCalGas.

[6] Sources: Exhibit PG&E-3 (Volume 1, Chapter 2, page 14-15) of Application 25-05-009 (PG&E 2027 GRC); 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).

achieving safe, reliable, affordable, and clean gas and electric service.[7] The CPUC then oversees the implementation of the GRC through many proceedings and programs, striving for cost containment wherever possible.[8] In addition to the GRCs, the CPUC has the opportunity to include cost containment measures in rulemakings.

Key Highlights

Utility Rates Continue to Trend Above Inflation

- Electric bundled system average rates (SAR) for PG&E, SCE, and SDG&E have generally risen since 2017 and have outpaced inflation since 2021.
- Between 2017 – 2026, electric bundled residential average rates (RAR) increased on average about 8 percent, 10 percent, and 8 percent per year for PG&E, SCE, and SDG&E, respectively, compared to an inflation rate of 3.6 percent over the same period.
- Residential Average Rate is expected to continue increasing above inflation through 2029, although at a slower pace than previously: about 4 percent for PG&E and SCE, and about 6 percent for SDG&E on an average annual basis, compared to an assumed inflation rate of 3.2 percent over the same period.

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

Wildfire-Related Costs

- Wildfire-related costs authorized for recovery on January 1 for the years 2020—2026 were approximately $54 billion, resulting in an equivalent revenue requirement over this time period of about $37 billion.[9]
- Wildfire-related revenue requirement[10] on January 1, 2026[11] made up about 18 percent of PG&E's total revenue requirement and 14 percent respectively of SCE and SDG&E's total revenue requirements.

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[7] In each of the electric IOU's last rate cases, the CPUC approved revenues at lower amounts than that requested by the utilities, with cost savings totaling of billions of dollars.

[8] Certain aspects of GRC and other proceedings are not within the CPUC's cost containment purview, for example market costs for natural gas and renewables, inflation and other factors affecting the price of goods and services, such as import tariff policy, and high interest rates.

[9] 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. *See* Chapter 2 for more information about how capital-related costs are converted to revenue requirement.

[10] A revenue requirement is the total amount a utility is authorized to collect from customers at a given point in time to cover its costs.

[11] January 1 revenue requirement data may not represent revenue requirement over the full course of the year. For example, revenue requirement removed from rates after January 1 will not reflect a full year of collection.

These wildfire-related revenue requirements accounted for between 10 and 14 percent of residential customers' electricity bills, depending on the IOU, translating to an average annual cost per residential customer of roughly $288 to $348.[12]

- Wildfire mitigation costs, driven in part by climate change, are projected to continue their upward trend as indicated in the 2026 – 2028 wildfire mitigation plans (WMPs) filed by the IOUs with the Office of Energy Infrastructure Safety (Energy Safety).

Rooftop Solar-Related Costs

- Rooftop solar program costs in 2025 resulted in about $8.3 billion being shifted to customers without rooftop solar statewide.[13]
- This cost estimate accounts for between 12 and 20 percent of the electricity bill of non-participating residential customers, depending on the IOU, which translates to an average annual cost of roughly $264 to $492 for customers without rooftop solar.[14]

Distribution System Non-Wildfire Related Costs

- Across the IOUs, non-wildfire-related distribution system revenue requirement has risen at an annual average of approximately 11 percent since 2020.
- The cost of upgrading the primary and secondary distribution grid to meet electrification needs through 2040 is anticipated to grow, with new sources of demand such as electric vehicles, data centers, and building electrification expected to drive load growth.[15]

Generation System Costs

- Generation bundled rates are higher than if they would have grown at inflation but have decreased in recent years largely due to recent declines in CAISO market prices.
- These decreases have been driven largely by milder weather years and new capacity coming online, but rates could go up again if California experiences years that are less mild and increased demand outpaces new resources coming online.

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[12] Typical 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.

[13] The rooftop solar program cost shift analysis also applies to NEM/NBT customers, although the vast majority of this cost burden is shifted to non-NEM customers since much of NEM customers' bills are offset by the NEM systems.

[14] 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.

[15] IOU estimates are based on each utility's Electrification Impact Study report data; *see* Chapter 2 for more information.

Combined Natural Gas Revenue Requirements Maintain Upward Trend

- The combined 2026 gas revenue requirement of California's three largest gas utilities has increased by 74 percent since 2016.

CPUC Cost Containment Recommendations

General Rate Cases are a primary area where the CPUC aims to control costs, but it is not the only cost containment opportunity. The CPUC considers and aims to control costs in all proceedings and in informal venues such as Energy Division's resolution process. The list below provides examples of electrification-related rulemakings addressing cost containment; this list is not exhaustive.

Electrification-Related CPUC Rulemakings with Cost Containment
High Distributed Energy Resources (DER) Rulemaking R.21-06-017 • Electrification Impact Study Part 2 (EIS2) reports served by the three large electric IOUs to the High DER rulemaking service list in January 2026 assess distribution costs required to support California's electrification goals, including the potential of widespread electrification to improve long-term customer affordability.
Long-Term Gas Planning Rulemaking R.24-09-012 • In D.25-12-042, the CPUC designated initial priority neighborhood decarbonization zones, as required by SB 1221, in census tracts that have supportive local government or community partners and contain a concentration of gas distribution line replacement projects. These decarbonization zones are opportunities to pilot electrification projects that are comparatively less costly than traditional gas line replacement projects.
California Climate Credit (CCC) Rulemaking R.25-07-013 • A decision issued April 2026 in Phase 1A of the rulemaking took immediate action[16] to move the large electric IOUs' residential CCC[17] to August and September to provide maximum affordability relief when bills are highest.[18] Phase 1B of the rulemaking considers broader changes to the CCC and includes consideration of allocating the CCC based on usage.
Advanced Electric Rate Design Rulemaking R.26-04-009 • The rulemaking will establish advanced electric rate design policies to update residential and non-residential rate structures and their underlying cost inputs so that rates more accurately reflect the cost of providing service, send price signals that support efficient use of grid infrastructure, and allocate costs fairly across all

[16] Immediate action was taken to comply with actions to comply with statutory deadlines imposed by AB 1207 which among other things requires that the CCC be provided on the bills of residential customers in no more than four high-billed months of each year to maximize customer electric bill affordability.

[17] IOUs are allocated allowances annually under the Cap-and-Invest Program which are be sold each year at quarterly California Air Resources Board (CARB) auctions; proceeds are delivered in part as a twice-per-year lump-sum bill credit automatically provided to all bundled and unbundled residential electric customers and certain qualifying small business electric customers as the CCC.

[18] *See* D.26-04-036. The small electric IOUs' residential CCC was moved to October and November.

Electrification-Related CPUC Rulemakings with Cost Containment
customers19. Specifically, the rulemaking will consider, among other things, new rate tariffs for data centers, improvements that modernize residential and nonresidential rate designs, and streamlining marginal cost methodologies.
Building Decarbonization Rulemaking R.19-01-011 • D.25-06-034 authorized 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 when electrifying a home. Such technologies could potentially result in significant ratepayer and customer savings, in addition to eliminating wait times for utilities to install new infrastructure.

II. Costs, Revenue Requirements, and Rates

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.[20] 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.

Revenue Requirement

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

Capital-related revenue requirement = Capital expenditure depreciation expense (net of related tax effects) and other capital-related expenses + Cost of capital

*Cost of capital = (Return on equity * Equity portion of rate base) + Debt service expense*

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

Background

Electric and gas utilities file detailed descriptions of the costs of providing service and request authorization to collect these costs in various ratesetting proceedings. Most utility costs, other than the cost of procuring fuel and purchased power, are generally addressed in General

[19] Pursuant to SB 57, the rulemaking will also evaluate appropriate rate design strategies to mitigate stranded costs and cost under-recovery associated with data centers and other large loads.

[20] In 2025, 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 2024 California Gas Report, SoCalGas had about 6.0 million customers, PG&E had about 4.5 million, and SDG&E had about 0.9 million.

Rate Case (GRC) proceedings.[21] The GRC establishes the authorized annual revenue (called "revenue requirement") required for a utility to cover the costs of serving its customers and a fair return or profit on its investments for shareholders. GRCs are forward-looking: a utility forecasts and estimates its anticipated costs to operate the 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.[22]

During electric and gas GRCs and other ratesetting proceedings, costs are classified into two major categories: operating expense and capital-related costs.[23] Operating expense and capital-related cost authorized for recovery during ratesetting proceedings must be converted to the revenue requirement to be collected from ratepayers through rates. To fully understand electric and gas utility revenue requirement, it is necessary to understand the difference between these two categories.

Operating expense revenue requirement is generally passed through to ratepayers each year at cost and is recovered on an immediate dollar-for-dollar basis. Operating expense includes: 1) operations and maintenance (O&M) expenses and 2) 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.

Capital-related revenue requirement includes: 1) capital expenditure depreciation expense recovered over a long period of time and other capital-related expenses[24] and 2) cost of capital, which includes an authorized profit on capital invested by the utility and recovery of debt service expenses.[25] Depreciation expense spreads the cost to ratepayers of the capital investment over each underlying asset's useful life, generally a long period of time.[26] **Cost of capital**, an overall financing cost also known as rate of return (ROR), is calculated over the net book value[27] of the utility's assets known as "rate base" and has two main components: the authorized profit percentage known as return on equity (ROE) applied to the equity portion of rate base and recovery of debt service expense.[28] Rate base is used as the basis for the **return on rate base revenue requirement.** When net book value increases–which has generally been the case for

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[21] 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. For more detailed descriptions of how GRC and other proceedings authorize utility revenue requirements, *see* the 2025 Assembly Bill (AB) 67 Report.

[22] A cost allocation proceeding follows the revenue-setting GRC to allocate revenue requirement to specific customer groups.

[23] Capital-related cost here includes the weighted average cost of capital i.e. weighted average cost of return on equity, debt and preferred equity. All cost that is not capital-related is considered operating expense here.

[24] Depreciation expense is net of related tax effect. Other capital-related expenses include: 1) the tax associated with the capital investment earnings itself, i.e. income taxes, as ratepayers pay the income taxes on the allowed return (profit) that the utility is authorized to earn, as well as other taxes such as property taxes; and 2) debt service expense.

[25]The authorized profit is calculated solely on the equity portion of capital investments and is also known as "earnings." Debt service is considered a cost to be recovered, not profit.

[26] Utility assets can have a useful life of up to 40 years or more.

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

[28] ROE and the equity portion of rate base to which it is applied to calculate authorized profit, or earnings, as well as the authorized debt service percentage to be applied to the debt portion of rate base are determined during CPUC Cost of Capital proceedings.

PG&E, SCE, and SDG&E–rate base increases.[29] Increases in rate base over time thus directly result in increases in the return on rate base revenue requirement and ultimately the capital-related revenue requirement.

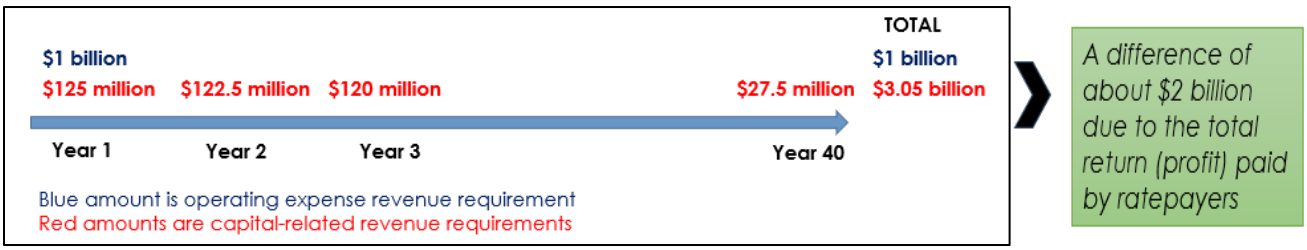
Under this approach, when a utility invests capital in an asset, it does not recover the full investment in the year it is made. Instead, the utility collects a portion of the investment (depreciation), plus an authorized profit for the equity-financed portion and recovery of debt service expense, similar 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, which can be up to 40 years.

Bundled Average Rates

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

As a result, dollar-for-dollar, costs resulting in operating expense revenue requirement have a more immediate impact on rates than 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 7.6 percent return on the undepreciated capital asset ("return on rate base") over the theoretical capital asset life of 40 years, or a total of about $3.05 billion.[30] This results in about an additional $2 billion total in costs to ratepayers over the long term.

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



Electric Cost Drivers and Rate Trends

[29] If a utility adds new assets at a rate that is greater than the retirement of existing assets, rate base increases.

[30] For simplification, depreciation is on a straight-line basis with no asset salvage value.

The revenue requirement is derived from cost data and is what a utility has been authorized to collect from all customers in billing charges in order to provide safe and reliable service.[31] Once the revenue requirement is established, rates are developed against a backdrop of dynamic factors, including demand growth and inflation. Bundled and unbundled system average rates are developed based on the allocation of revenue requirement and sales to these two types of customers.[32] Class tariffs can then be designed to collect the revenue requirement assigned to each customer class e.g., residential, small commercial, medium commercial, large commercial, etc.

System-level rate data can be grouped to show high-level cost drivers that affect all customer classes over time by functional components: generation, distribution, transmission, and other programs and charges.[33] Over time, trends can be seen in the changes in the absolute value of the functional rate components, as well as the relative value of the components to the total rate.[34]

Figure 2, below, shows the combined rates in effect for PG&E, SCE, and SDG&E at bundled system average rate (SAR) level, classified by rate component, with the distribution and transmission rate components further classified into non wildfire-related (solid area) and wildfire-related[35] (textured area) portions.[36] A line has been added to represent the combined total bundled SAR if it had grown at the assumed rate of inflation.[37] For individual IOU bundled SAR data that sums to the data in Figure 2, see Appendix C.

[31] *See* the Background section earlier in this chapter for how revenue requirement is derived from cost data.

[32] Bundled IOU customers take all services–generation, transmission, and distribution services–from the IOU; unbundled customers take transmission and distribution services from the IOU, with generation service provided by a separate load serving entity.

[33] *See* Appendix B for definitions of the costs that correspond to these rate components.

[34] Throughout this chapter, figure or table data is from IOU data responses to SB 695 Report data requests and utility rate implementation advice letters. Utility rate implementations may not occur on January 1, in which case rates effective January 1 (from the previous rate implementation) is shown. Ten years of data is shown. Data in current report may be restated from previous reports. All dollars are nominal i.e., not adjusted for inflation unless otherwise indicated.

[35] Total wildfire mitigation and wildfire liability (insurance and catastrophic events) costs are known collectively here as "wildfire-related costs." 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 may also be included.

[36] Data is anchored to January 1 of each year to maintain consistent year-over-year comparisons. The combined total system revenue requirement bar chart shown in previous years' reports has been changed in this year's report to show bundled system average rates. Generation revenue requirement shown in previous years' reports is not directly comparable to the generation rates shown in this year's report as the previous revenue requirement data included unbundled customer data, specifically the unbundled Power Charge Indifference Adjustment (PCIA) revenue requirement. The bundled generation rates reflected in Figure 2 do not include unbundled customer data by definition. To view Figure 2 using the same total system revenue requirement basis as in previous years' reports, *see* Appendix C.

[37] Inflation rate 2017 base year to 2026 is 3.6 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 January 2026).

Figure 2: PG&E, SCE, and SDG&E Combined Electric Bundled System Average Rates, by Rate Component with Inflation-Adjusted Rate Comparison (January 1, $/kWh)

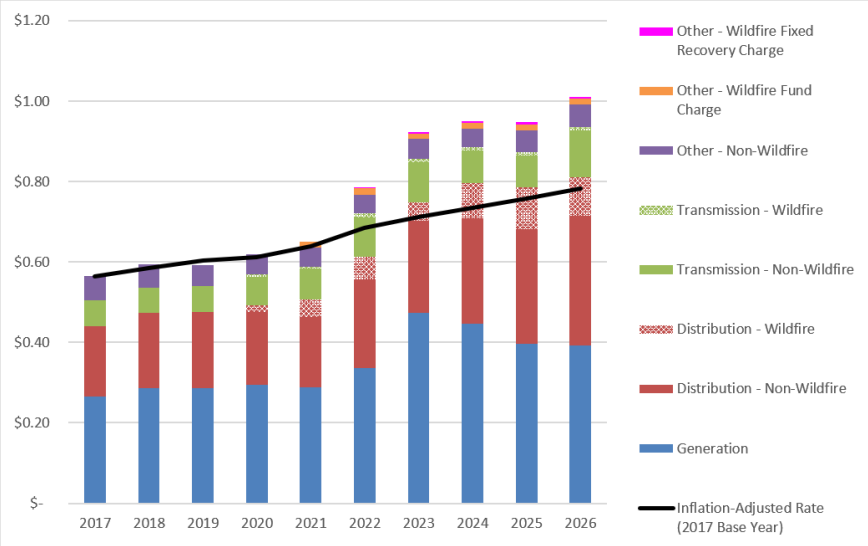


Figure 2, above, shows generally increasing combined bundled system average rates (SAR) since 2017 with significant growth occurring since 2021.[38] Trends in functional rate components, with wildfire-related breakouts, are described below. Cost drivers are specifically identified as such.

- **Generation Cost Drivers (Blue):** Generation rates for bundled customers in 2026 are slightly higher than if they had grown at the rate of inflation, but lower than they were in the 2023-2024 period. A key driver of generation rates are the price volatility of CAISO energy market purchases and Resource Adequacy.[39]
- **Distribution—Non Wildfire-Related Cost Drivers (Dark Red)**: Rates corresponding to revenue requirement for power lines, poles, transformers, and repair crews, whether for replacement or new infrastructure, have grown significantly over time, almost double in 2026 compared to 2017.[40]
- **Distribution—Wildfire-Related Cost Drivers (Textured Red)**: From 2021 to 2026, wildfire-related distribution rates reflecting vegetation management, infrastructure hardening, and wildfire insurance,

[38] The combined bundled SAR decrease in 2025 compared to 2024 is primarily due to PG&E's SAR, primarily due to the removal in 2024 of a large revenue requirement corresponding to wildfire-related costs and a generation cost adjustment. All three large electric IOUs experienced bundled SAR rate decreases at various points over the period 2023 – 2026, *see* individual IOU bundled SAR rate decreases over this period in Appendix C.

[39] The combined generation rate in 2017 was $0.27/kWh; if the rate had grown at the rate of inflation it would have been $0.37, compared to the combined generation rate in 2026 of $0.39/kWh.

[40] Included here as well is the new and upgraded distribution capacity and electrification programs (i.e. transportation electrification programs) revenue requirements, collectively referred to here as the electrification-driven revenue requirement, however it is currently not a cost driver. This is a new cost category that has begun to be monitored in this report; more information is available later in this chapter. Electrification-driven costs authorized for recovery on January 1 for the years 2025—2026 are approximately $4 billion, resulting in an equivalent revenue requirement over this time period of about $0.7 billion. *See* Appendix C for underlying data.

and other wildfire-related distribution revenue requirements,[41] increased over 100 percent, in step with the total distribution revenue requirement, indicating that the wildfire-related distribution revenue requirement is a substantial driver of the large total distribution revenue requirement increase over this period.

- **Transmission—Non Wildfire-Related Cost Drivers (Green):** Rates corresponding to revenue requirement for existing and new transmission projects, consisting of lines and substations, reconductoring, and some grid enhancing technologies and other upgrades have increased over 100 percent since 2017.
- **Transmission—Wildfire-Related (Textured Green), Wildfire Fund Charge (Orange) and Wildfire-Related Securitization Cost Drivers (Pink):** The combined rates reflecting the revenue requirements of these other, non-distribution wildfire-related rates have been constant since 2022; however, taken together with distribution wildfire-related rates, the resulting total wildfire-related rate reflects a cost driver.[42]
- **Other—Non-Wildfire-Related (Purple):** Rates reflecting the revenue requirement corresponding to funding certain programs or for certain charges have been generally constant since 2017.[43]

Deep Dive on the Largest Contributors to Cost and Rates

Along with the wildfire-related cost drivers identified above, Net Energy Metering (NEM) and Net Billing Tariff (NBT) program cost trends are included below.[44]

Wildfire-Related Costs

Across IOUs, wildfire-related *costs* authorized for recovery on January 1 for the years 2020—2026 to support the state's wildfire prevention and response efforts total approximately $54 billion, resulting in an equivalent *revenue requirement* collected over this time period of about $37 billion.[45] The $54 billion cost data across IOUs is on average about 35 percent capital-related and about 65 percent operating expense. Figure 3, below, illustrates the effect of the immediate inclusion of operating expense costs into revenue requirement

[41] Other wildfire-related distribution costs include, for example, situational awareness costs.

[42] *See* Appendix B for definitions of the Wildfire Fund Charge and Wildfire-Related Securitization.

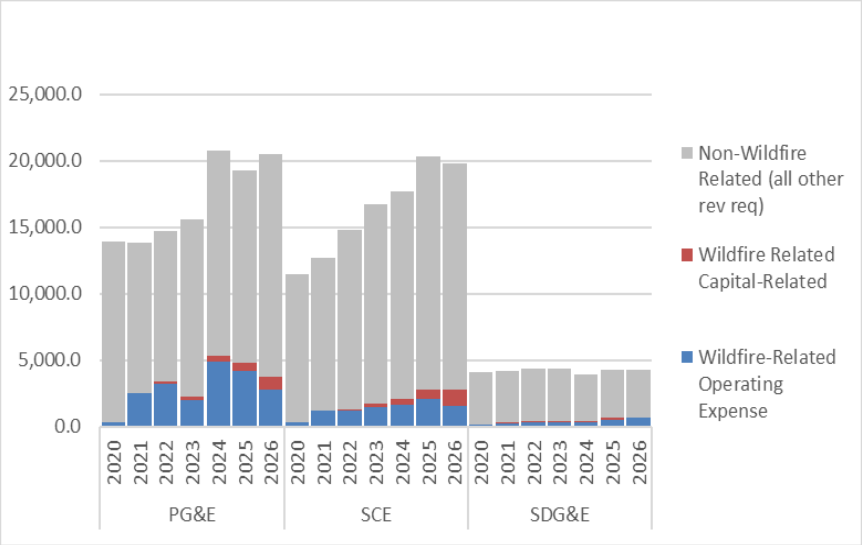
[43] Includes public purpose programs funding, new system generation charges, competition transition charges, nuclear decommissioning, and greenhouse gas revenue returns. *See* Appendix B for definitions of each revenue requirement component.

[44] Transmission cost drivers are not discussed in this report; for more information about transmission cost drivers, *see* the CPUC's AB 3264 Working Concepts in Transmission Financing and Ownership Report. A final AB 3264 report on this subject will be issued at a later date.

[45] Costs authorized to be placed into rates are larger than the corresponding revenue requirement that is collected each year as large capital-related costs will go into rates as revenue requirement gradually over a long period of time. For more information, including an example that illustrates this concept, *see* Figure 1. Cost data should not be used as an estimate of the amount collected; that estimate is better represented by revenue requirement. January 1 revenue requirement data may not represent revenue requirement over the full course of the year. For example, revenue requirement removed from rates after January 1 will not reflect a full year of collection. For this reason and also due to regulatory accounting mechanisms, January 1 revenue requirement may not reflect amounts actually collected from customers. *See* Appendix C for underlying data.

(blue bars) compared to the gradual inclusion of the capital-related costs (red bars).[46] The capital-related revenue requirement will continue to grow over time as new wildfire-related assets are added due to: 1) stacking of the underlying annual depreciation expense of the assets and 2) the corresponding rate of return calculated over the stacked net asset value.

Figure 3: Wildfire-Related Revenue Requirement by Capital-Related and Operating Expense, Relative to Total Revenue Requirement (January 1, $ Millions)



The January 1, 2026 wildfire-related revenue requirement in Figure 3 is shown below for each IOU.,

- PG&E: $3.8 billion, or about 18 percent of total revenue requirement
- SCE: $2.8 billion, or about 14 percent of total revenue requirement
- SDG&E: $0.7 billion, or about 14 percent of total revenue requirement

[46] Wildfire-related operating expense revenue requirement (blue bars), include vegetation management efforts and wildfire insurance coverage. Over the 2020 – 2026 period, each IOU's average wildfire-related operating expense revenue requirement to total revenue requirement is about: PG&E 16 percent; SCE 8 percent; and SDG&E 9 percent. Wildfire-related capital expense revenue requirement (red bars) include system hardening e.g. installing covered conductor or undergrounding portions of a distribution system. Each IOU's average wildfire-related capital-related expense revenue requirement to total revenue requirement over this period is about: PG&E and SCE 2 percent; and SDG&E 1 percent. SDG&E total revenue requirement is relatively flat over the 2020 – 2026 period, however its bundled SAR rose substantially; this effect is the result of lower forecasted sales in the bundled SAR calculation relative to the corresponding revenue requirement, potentially due to factors such as generation load departure.

The revenue requirement data in Figure 3 results in the wildfire-related portion of a bundled residential non-CARE customer average monthly bill shown in Table 1.[47]

Table 1: PG&E, SCE, and SDG&E Wildfire-Related Portion of Typical Average Monthly Bill, Bundled Residential Non-CARE Customers (January 1, 2026)

	Wildfire Mitigation	Wildfire Liability	Total Wildfire-Related	Total Monthly Bill	Total Wildfire-Related Portion (%)
PG&E	$24	$5	$29	$203	14%
SCE	$19	$7	$26	$182	14%
SDG&E	$11	$8	$19	$187	10%

Starting in 2024 and continuing through subsequent years, substantial wildfire-related 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.[48] These removals decrease wildfire-related operating expense in the revenue requirement; however, on-going capital-related revenue requirements will continue to be collected over the life of the underlying assets. New wildfire-related revenue requirements will also be added as pending proceedings conclude. Furthermore, the IOUs will continue to file new wildfire-related cost recovery applications for costs recorded in wildfire-related memorandum accounts, including wildfire liability cost recovery.[49]

Electric utilities are required 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.[50] Future wildfire mitigation authorized costs and resulting revenue requirements can be directionally illustrated by comparing each IOU's wildfire-mitigation cost as shown in

[47] 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. 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. Bills calculated using each IOU's Q1-2026 Cost and Rate Tracker.

[48] *See* these revenue requirement reductions in Appendix C.

[49] While the majority of wildfire mitigation forecast costs are now included in an IOU's General Rate Case (GRC), IOUs may seek after-the-fact recovery of costs recorded in wildfire mitigation-related memorandum accounts for certain incremental spending. PG&E's 2023 GRC, SCE's 2025 GRC, and SDG&E's 2024 GRC decisions prohibited recording wildfire-related amounts in *balancing* accounts that exceed the authorized revenue requirement as these accounts are now one-way balancing accounts. However, the IOUs may continue to record costs that exceed authorized budget in *memorandum* accounts, for which cost recovery requires an application to be filed.

[50] Energy Safety announced in January 2026 that it will not be accepting 2027 WMP Updates as each IOU will submit a new Base WMP in 2027 covering the four-year period of 2028-2031.

its most recently approved 2026- 2028 Base WMP to its previously filed WMP as shown in Table 2.[51] Energy Safety approved 2026 – 2028 Base WMP amounts may not reflect wildfire-mitigation related amounts subsequently approved in CPUC proceedings.

Table 2: Actual 2023-2025 and Projected 2026 - 2028 Wildfire Mitigation Cost by Operating Expenditures (OpEx) and Capital Expenditures (CapEx) ($ billions)

	Actual 2023 – 2025 WMP OpEx	Actual 2023 – 2025 WMP CapEx	Actual 2023 – 2025 WMP Total Wildfire Mitigation Cost	Projected 2026 – 2028 WMP OpEx	Projected 2026 – 2028 WMP CapEx	Projected 2026 – 2028 WMP Total Wildfire Mitigation Cost
PG&E	$6.7	$10.0	$16.7	$6.3	$12.4	$18.7
SCE	$2.4	$3.6	$6.0	$3.0	$4.0	$7.0
SDG&E	$0.6	$1.3	$1.9	$0.5	$0.5	$1.0
Total	**$9.7**	**$14.9**	**$24.6**	**$9.8**	**$16.9**	**$26.7**

- PG&E: 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,[52] PG&E's wildfire mitigation costs, particularly capital expenditures, are expected to continue to grow.
- SCE: SCE's 2026 - 2028 WMP cycle shows higher planned spending than approved spend in the previous cycle; however, its wildfire mitigation costs were approved by the CPUC in its 2025 GRC decision at lower levels than those shown in Table 2.[53] While its approved wildfire mitigation costs may be lower, significant uncertainty regarding its wildfire liability with respect to the Eaton Fire requires tempering any expected decrease in overall wildfire-related costs.
- SDG&E: While SDG&E's 2026 - 2028 WMP cycle projected expenditure data is almost half of its previous cycle actual data, this reduction reflects SDG&E's statement in its 2026 - 2028 WMP that

[51] Projected 2026 – 2028 WMP costs are from each IOU's 2026 – 2028 Base WMP. CapEx is capital expenditure only (i.e. does not include return on rate base). Cost is expenditure and is not stated in equivalent revenue requirement. 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. The amounts shown in the table are based on the year the cost is expected to be incurred and do not reflect if and when the cost will be authorized for recovery in rates. Accordingly, the data presented in the table is directional only in terms of the impact on future authorized costs and resulting revenue requirements.

[52] 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. Wildfire mitigation expenditures approved in an Electric Undergrounding Plan are incremental to WMP costs approved in a GRC. In its Q4-2025 earnings presentation, PG&E indicates it plans to file a 10-Year Undergrounding Plan in Q3-2026.

[53] *See* D.25-09-030. In its petition to amend its 2026-2028 WMP to align with the CPUC decision in SCE's 2025 GRC, required to be filed by Energy Safety, SCE indicates that total 2026-2028 WMP projected expenditures should be amended to approximately $4.4 billion.

reduced funding for strategic undergrounding as a result of the recent decision in its 2024 GRC has resulted in exploring the submission of an Electric Undergrounding Plan in accordance with SB 884. Therefore, SDG&E's wildfire mitigation costs are expected to grow in the future.

Net Energy Metering (NEM) and Net Billing Tariffs (NBT) Program Costs

Net energy metering (NEM) tariffs (NEM 1.0 and NEM 2.0, collectively NEM) and net billing tariffs[54] (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.

A "cost shift" occurs when one group of utility customers pays costs that would otherwise be paid by another group, with one group effectively subsidizing the other. The NEM design overpays NEM customers for their exported energy they send to the grid—which offsets the cost of their consumption—since the export rate received is close to full retail rate instead of at the price other customers would pay to purchase clean electricity from other sources.[55] Current residential NEM customers are compensated at about $0.38/kWh[56] for electricity that, according to the CPUC's 2024 Avoided Cost Calculator (ACC), is worth approximately $0.05/kWh.[57] The NEM tariff structure, and NBT tariff structure, also allows rooftop solar customers to avoid paying some of the fixed costs embedded in the volumetric portion of the retail rate to maintain the electric grid for all customers. This is because when NEM and NBT customers self-supply,[58] utility fixed costs are 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.[59] NEM/NBT program costs result in a cost shift to non-NEM/NBT customers that primarily reflects NEM/NBT customer bill savings resulting from the effects described above.[60]

In 2022, the CPUC adopted the NBT Decision in which a successor NBT design balances multiple statutory requirements and the needs of the electric grid, the environment and all other ratepayers.[61] The NBT also implements higher incentives for customers in low-income households than for other customers. Starting in April 2023, new rooftop solar customers or prior NEM customers at the end of their 20-year legacy

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[54] Includes subtariffs.

[55] The retail rate paid to NEM customers excludes only certain public purpose program and other non-bypassable charges (NBC).

[56] PG&E E-TOU-C: $0.47/kWh; SCE TOU-D-4-9: $0.27/kWh; SDG&E TOU-DR1: $0.48/kWh. All rates in effect January 1, 2026, and are based on off-peak TOU periods. Figure cited is rounded average of these rates less an NBC estimate of $0.03/kWh.

[57] 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.

[58] Self-supply is behind-the-meter (BTM) solar generation and consumption.

[59] This occurs because in California, the fixed costs of electricity services are primarily collected through the volumetric distribution rate component of customer bills. The base services charge implemented as a result of D.24-05-028 will, in some measure, help to reduce this cost shift effect on non-NEM customers, who have borne a disproportionate share of fixed costs for distribution infrastructure in recent years.

[60] The NEM cost shift is equal to NEM customer bill savings less utility avoided costs, where bill savings is the dollar amount that NEM customers avoid paying because of their self-generation and netting, and avoided costs are costs such as infrastructure upgrades that the utility should avoid incurring as a result of distributed generation.

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

interconnection periods receive compensation through the new NBT.[62] This compensation is more aligned with the value of the generation the systems provide to the grid since exports are paid at the avoided cost to the utility to buy clean electricity elsewhere.[63]

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.[64] This model compares NEM customer bill savings due to self-supply and netting[65] 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. While the NBT is an improvement to the NEM structure and reduces the cost shift compared to NEM, a cost shift still remains due to a NBT customer's ability to self-supply and avoid paying for some fixed costs to maintain the electric grid. The IOUs estimate the total NEM/NBT cost shift to be approximately $8.3 billion in 2025 as shown in Table 3.[66]

Table 3: PG&E, SCE, and SDG&E NEM and NBT Cost Shift, Year-End 2025 ($ Billions)

	All Customers				Residential Customers			
	NEM 1	**NEM 2**	**NBT**	**Total**	**NEM 1**	**NEM 2**	**NBT**	**Total**
PG&E	$1.2	$3.2	$0.3	**$4.7**	$0.8	$2.3	$0.3	**$3.4**
SCE	$0.7	$1.6	$0.1	**$2.4**	$0.6	$1.4	$0.1	**$2.1**
SDG&E	$0.3	$0.9	$0.0	**$1.2**	$0.3	$0.7	$0.0	**$1.0**
Total	**$2.2**	**$5.7**	**$0.4**	**$8.3**	**$1.7**	**$4.4**	**$0.4**	**$6.5**

As the cost shift scales with installed capacity, Table 4, below, shows each residential cost shift in terms of MW installed capacity. This provides a consistent basis for cost shift comparison across tariffs.

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

[63] The NBT also includes more favorable price signals for systems with battery storage compared to rooftop solar alone.

[64] The NEM cost shift is an arithmetic (subtraction) equation based on the Ratepayer Impact Measure ratio in the CPUC's Standard Practice Manual. A currently underway Net Billing and Related Tariffs Evaluation, ordered as part of D.23-11-068, may evaluate cost shift assumptions across the utilities and interested parties.

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

[66] IOU estimates are provided in data responses. Data includes a proxy generation rate for unbundled customers that is the same as for bundled customers. PG&E 2025 data is modeled in a cost shift model that has been redeveloped to adapt to changing regulations, increase analytical resolution, and allow for more scalable modeling techniques; comparisons of PG&E 2025 data to previous years' data may not be consistent based on the different modeling used for these periods. For PG&E, capacity factor modeling applies baseline territory specific hourly capacity factors to the installed capacity, based on solar generation profiles from the PVWatts Calculator. For SCE and SDG&E, capacity factor is modeled at or less than the capacity factors published by the California Energy Commission as part of the 2024 Integrated Energy Report (Docket 24-IEPR-01). 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.

Table 4: PG&E, SCE, and SDG&E NEM and NBT Residential Cost Shift per MW Installed Capacity, Year-End 2025 ($/MW)

	NEM 1	NEM 2	NBT
PG&E	$536,841	$664,074	$444,614
SCE	$531,015	$524,596	$160,714
SDG&E	$611,660	$553,580	$192,438

NEM costs have increased over the past several years, driven by:[67]

- 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 installed capacity growth year-over-year until the mid-April 2026 final deadline for NEM 2.0 interconnection.[68] This results in more NEM kilowatt-hours over which NEM compensation is paid and over which some fixed costs are avoided.[69]

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 4.[70]

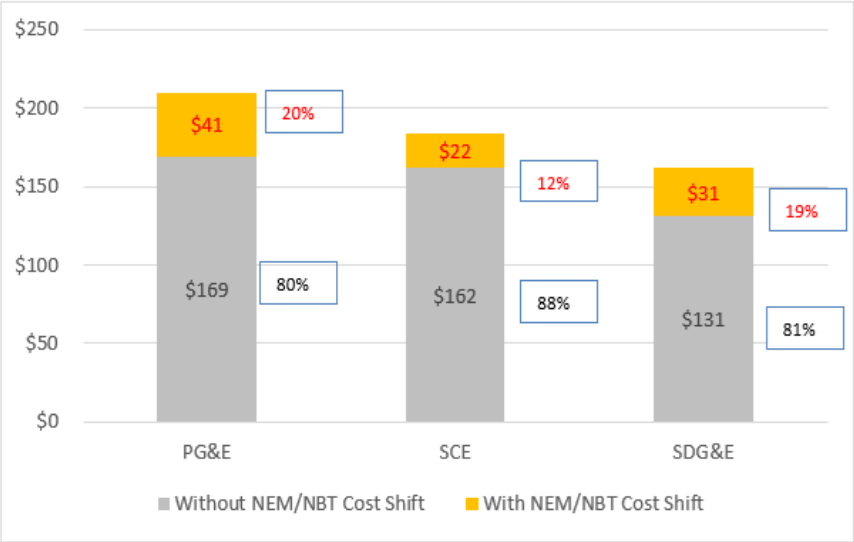
[67] Appendix C contains graphs that illustrate these two effect. The graphs combine the residential NEM and NBT cost shift data in Table 3 with residential installed capacity data for each utility over 2016 – 2025. The graphs reflect roughly flat NEM 1.0 installed capacity data, meaning that higher IOU rates over this time period primarily drove the NEM 1.0 cost shift. For NEM 2.0, both higher installed capacity data and higher IOU rates drive the substantial NEM 2.0 cost shift. SCE and SDG&E modeling show some tapering of the NEM 2.0 cost shift after 2024 as the installed capacity growth rate decreased, however, PG&E data shows continued NEM 2.0 cost shift growth. This effect may be due to the change in PG&E cost shift modeling between 2024 and 2025. The costs NEM customers shift onto non-participants will gradually decline as individual legacy periods expire, but the decline will be lengthy and gradual as it is expected that most NEM customers will transition to NBT rather than cease on-site generation.

[68] Although the April 2023 NEM 2.0 enrollment deadline has passed, eligible NEM 2.0 projects continue to be interconnected. Pending projects must receive final inspection clearance and permission to operate by mid-April 2026; after this date, it is expected that new NEM 2.0 installed capacity will begin to decrease. NEM 2.0 tariff variations (Virtual Net Energy Metering and Net Energy Metering Aggregation) have a later NEM 2.0 final inspection clearance date.

[69] *See* California Distributed Generation Statistics, Statistics and Charts, NEM and Rule 21 Interconnections. All three large electric IOUs show continual annual increases in NEM solar PV total capacity across residential and non-residential sectors and across all years.

[70] Wildfire-related nonbypassable rate components are: Wildfire Fund Charge (PG&E, SCE, and SDG&E) and Wildfire Securitization Fixed Recovery Charges (PG&E and SCE). Bill portion modeling is done in each IOU's Cost and Rate Tracker for Q4-2025 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). Unbundled residential customers, such as those who take generation service from a Community Choice Aggregator (CCA), may have different results. Usage data primarily reflects non-NEM customers usage data bill data as much of NEM participants' bills are offset by the systems themselves.

Figure 4: NEM/NBT Cost Portion of a Typical Non-NEM Residential Customer Monthly Bill (2025)



Combined NEM/NBT and Wildfire-Related Costs

The cost shifts associated with roof top solar programs and wildfire related spending were previously shown in Figure 4 and Table 1, respectively. Table 5, below, shows the combined monthly cost of these two major cost drivers.[71] The sum of wildfire-related monthly costs plus the wildfire-related adjusted NEM/NBT program monthly cost is $45 to $60 for customers without rooftop solar.

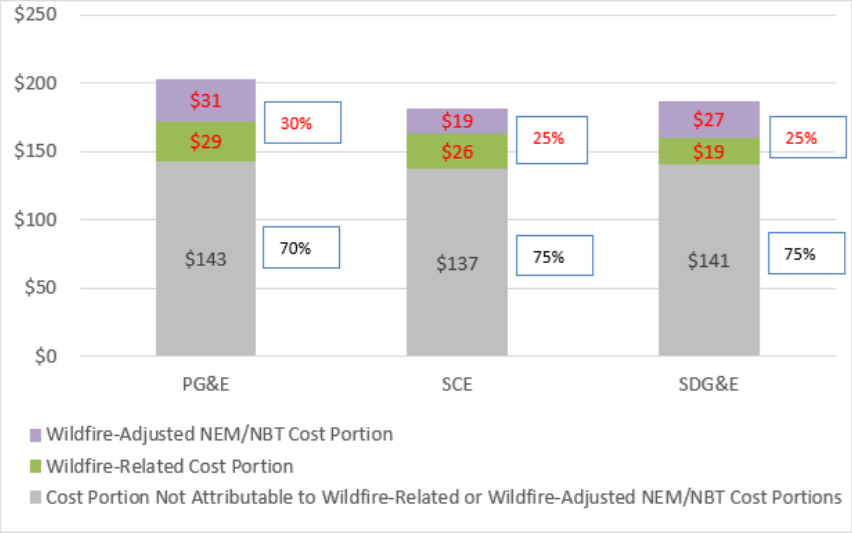
Table 5: Combined Wildfire-Related and Wildfire-Adjusted NEM/NBT Cost Portions of a Typical Non-NEM Residential Customer Monthly Bill

	Wildfire-Related Cost Portion January 1, 2026 (See Table 1) (A)	Wildfire-Adjusted NEM/NBT Cost Portion (B)	Combined Wildfire-Related and NEM/NBT Cost Portion (C) = (A) + (B)	Typical Average Monthly Bill January 1, 2026 (See Table 1) (D)	Combined Wildfire-Related and NEM/NBT Portions (%) (E) = (C) / (D)
PG&E	$29	$31	$60	$203	30%
SCE	$26	$19	$45	$182	25%
SDG&E	$19	$27	$46	$187	25%

[71] The sum in column C and the percent in column E of Table 5 as well as the data represented in red in Figure 5 are approximate, as the wildfire-related monthly cost is based on January 1, 2026 data and the wildfire-adjusted NEM/NBT monthly cost is based on year-end 2025 cost data.

Figure 5, below, shows the data in Table 5.

Figure 5: Combined Wildfire-Related and Wildfire-Adjusted NEM/NBT Cost Portions of a Typical Non-NEM Residential Customer Monthly Bill



Cost Drivers to Continue Monitoring

Electrification-Driven Projected Costs

While not yet a significant cost driver, the cost of upgrading the primary and secondary distribution grid to meet electrification needs through 2040 is estimated by the IOUs to be substantial, with new sources of demand such as electric vehicles, data centers, and building electrification expected to drive load growth. In January 2026, each IOU issued an Electrification Impacts Study Part 2 (EIS2) Report ordered as part of the High Distributed Energy Resources (DER) Rulemaking to assess distribution costs through 2040 required to support California's electrification goals.[72] Each IOU's EIS2 Report estimates a range of the potential costs of upgrading the primary and secondary distribution grid to support new electric demand under different scenarios. In the scenarios, energy demand that drives the distribution planning and investment process is based in part on the California Energy Commission (CEC) 2023 Integrated Energy Policy Report (IEPR) Local Reliability Managed Sales Forecast.

Table 6, below, shows a comparison of each IOU's: 1) EIS2 Report cost estimates from 2025 to 2030 for the base scenario, which includes certain basic mitigations such as existing demand flexibility applications and 2) new and upgraded distribution grid costs authorized in recent GRCs or requested in recent GRC

[72] The reports are Part 2 of the EIS study process and build on the EIS Part 1 report issued by consultant Kevala which focused on high-level statewide modeling. *See* R.21-06-017 for more information.

applications.[73] Cost estimates from 2025 to 2040 are also included for reference purposes. The sum of PG&E's authorized and requested costs is about $11.1 billion, which is similar to PG&E's EIS2 Report 2030 estimate of $11 billion. Additional new and upgraded distribution grid cost information for the years 2029 – 2030 (SCE) and 2028 – 2030 (SDG&E) will be available when each IOU files its next GRC application; it is expected that these applications, particularly that of SCE, will request authorization of a substantial amount of costs in this area consistent with the data in Table 6.[74]

Table 6: Comparison of Electrification Impact Study Part 2 Estimated Costs to Authorized or Requested New and Upgraded Distribution Grid Costs ($ Billions)

	Authorized New and Upgraded Distribution Grid Costs To Be Collected in Rates 2023-2026 (PG&E only)	Requested New and Upgraded Distribution Grid Costs Not Yet Collected in Rates 2027-2030 (PG&E only)	Authorized New and Upgraded Distribution Grid Costs To Be Collected in Rates 2025-2028 (SCE only)	Authorized New and Upgraded Distribution Grid Costs To Be Collected in Rates 2024-2027 (SDG&E only)	EIS2 Report, Base Case Estimated Costs 2025-2030	EIS2 Report Base Case Estimated Costs 2025- 2040
PG&E	$2.4	$8.7			$11.0	$25.5
SCE			$2.2		$8.9	$13.1
SDG&E				$0.3	$0.9	$3.2

New and upgraded distribution grid costs are heavily-weighted to capital investment (as opposed to, for example, wildfire-related costs which can have substantial operational expenses such as for vegetation management), and as such are not expected to be a significant portion of the total revenue requirement in rates over the next several years, as capital-intensive investments are gradually recovered over long timeframes.

Generation and Power Procurement Costs

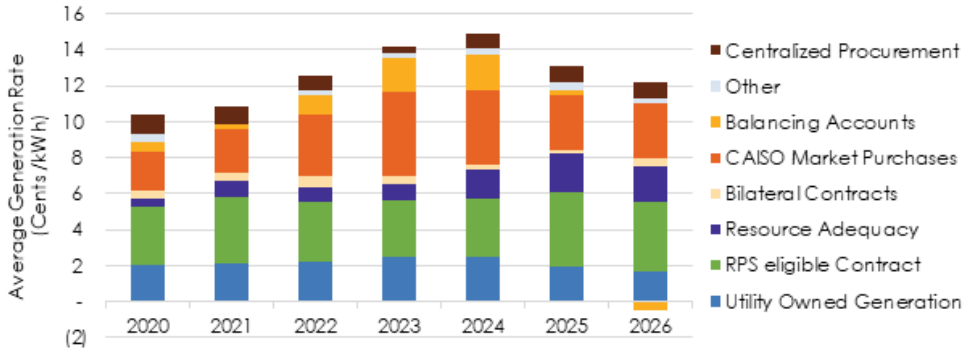
[73] PG&E data shows PG&E electrification-driven costs *authorized* as part of its 2023 GRC cycle, including interim costs authorized as part of its Electric Capacity and New Business Interim Memorandum Account (ECNBIMA), as well as *requested* in its 2027 GRC application, to be collected in rates through 2030 as well as interim costs authorized as part of its Electric Capacity and New Business Interim Memorandum Account (ECNBIMA) through the end of PG&E's 2023 GRC cycle. For SCE and SDG&E, authorized electrification-driven costs to be collected in rates through the last year of each's current GRC cycle (2028 and 2027, respectively) are shown, which does not allow for a direct comparison to the 2030 EIS2 Report data. Requested costs beyond 2027 for SDG&E and 2028 for SCE will be available when these IOUs file each's next GRC application, expected to be Q2-2026 for SDG&E and Q2-2027 for SCE.

[74] Estimated EIS2 report costs in $2025; cost is expenditure and is not stated in equivalent revenue requirement. Data shown is based on the year the cost is expected to be incurred; for requested amounts, data shown does not reflect if and when the cost will be authorized for recovery in rates. In addition, certain authorized costs, such as those related to SB 410, may have interim authorization, subject to refund to ratepayers after a reasonableness review. Accordingly, the requested cost data presented here is directional only in terms of the impact on future authorized costs and resulting revenue requirements.

Each IOU's generation revenue requirement is composed of three key elements: 1) the Energy Resources Recovery Account (ERRA), which recovers the costs to serve bundled load,[75] 2) the Power Charge Indifference Adjustment (PCIA), which recovers costs for all the long-term procurement obligations from bundled and departed load for costs incurred before the load departed, and 3) centralized procurement mechanisms, which are special types of procurement mechanisms the Commission has directed the IOU manage on behalf of the entire territory to serve specific reliability or public policy needs.[76]

Over time, the combined IOU revenue requirement for generation has decreased due to load departures from IOUs to Community Choice Aggregator service (CCA). However, generation rates for bundled customers in 2026 remain slightly higher than if they had grown at the rate of inflation.[77] Within the generation revenue requirement for bundled customers, a key driver of rates are CAISO market purchases, which are collected through the Energy Resource Recovery Account (ERRA). This cost component caused rate volatility in the 2023-2024 period as can be seen in the Figure 6, below.[78]

Figure 6: Components of Bundled Generation Rates All IOUs (cents/kWh)



CAISO market costs were the most significant driver of fluctuations in the revenue requirements for generation, accounting for $0.022/kwh in 2020 and increasing to $0.46/kWh in 2023 at its peak and declining to $0.031/kWh in 2026. These fluctuations were the result of tight market conditions that increased energy prices in the CAISO market. The recent decrease has been driven largely by milder weather years and new capacity coming online.

[75] Bundled load refers to customers who receive both electric generation and delivery service from an IOU. Departed load refers to customers who no longer receive generation service from the utility (such as customers served by a CCA, Electric Service Provider, or their own generation resources) but who may still receive transmission and distribution service from the utility.

[76] These include the Cost Allocation Mechanism (CAM), Centralized Procurement Entity (CPE), Public Purpose Programs, Reliability Must Run Contracts, and Diablo Canyon Extended Operations.

[77] The combined generation rate in 2017 was $0.27/kWh; if the rate had grown at the rate of inflation it would have been $0.37/kWh, compared to the combined generation rate in 2026 of $0.39/kWh.

[78] The Balancing Account category recovers costs the balances remaining in the Energy Resource Recovery Account and the Power Charge Indifference Adjustment Balancing account at the end of the year. Centralized procurement category includes all mechanisms listed in a previous footnote. Other Category includes common and indirect costs, interest and the Green Tariff Shared Renewables program and Direct greenhouse gas costs.

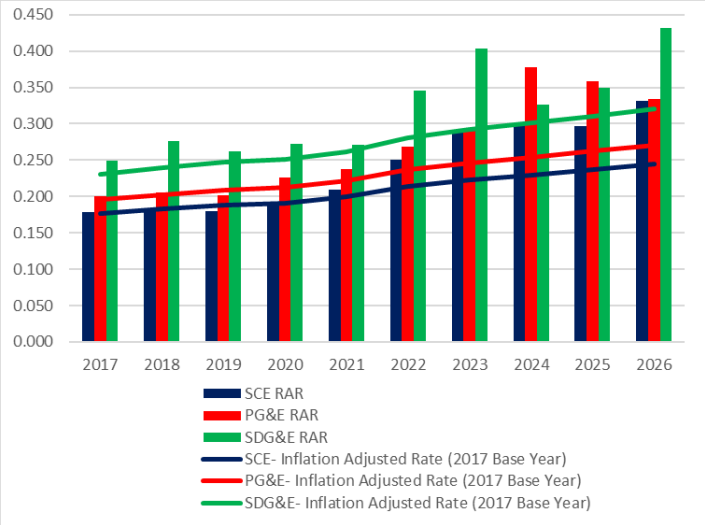
III. Electric Rate Forecasts

Rate trends allow comparison of how an IOU's rates track against another metric, such as 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.[79]

Bundled Residential Average Rate Historical Trends

To provide additional context for the electric rate forecasts in this chapter, historical bundled Residential Average Rate (RAR) are shown in Figure 7, below. A line has been added to each graph to allow comparison of how each IOU's bundled RAR has tracked inflation over time.

Figure 7: PG&E, SCE, and SDG&E January 1 Bundled Residential Average Rate, Nominal and Inflation-Adjusted Comparison ($/kWh)



[79] Other affordability considerations may not be apparent when viewing rates at class level and not at tariff level. For example, R.26-04-009 will consider, among other things, how advanced rate design policies can support equitable and affordable electric rates for Californians and advance the Commission's CPUC's Environmental and Social Justice Action Plan.

Since 2017, bundled RAR has increased at an average annual rate greater than the assumed rate of inflation: about 10 percent for SCE, and about 8 percent for PG&E and SDG&E.[80]

Bundled Residential Rate Forecasts

The current electric Cost and Rate Trackers (CRT) for PG&E, SCE, and SDG&E were used to produce rate forecasts.[81] 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 2026 – 2029 are shown in Table 7.[82]

Table 7: PG&E, SCE, and SDG&E Forecasted Bundled Residential Average Rates (nominal $/kWh)

Bundled Residential Average Rate	Year-End				
	Actual 2025	Projected 2026	Projected 2027	Projected 2028	Projected 2029
PG&E Nominal Rate	$ 0.357	$ 0.329	$ 0.371	$ 0.390	$ 0.408
SCE Nominal Rate	$ 0.333	$ 0.328	$ 0.334	$ 0.352	$ 0.385
SDG&E Nominal Rate	$ 0.373	$ 0.423	$ 0.439	$ 0.460	$ 0.467

The percentage change in forecasted year-end 2029 bundled residential rates over actual year-end 2025 rates for each IOU are shown below. The average annual increase is a simplified average whereby the total

[80] 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. Compound annual growth rates could be significantly different. Inflation rate 2017 base year to 2026 is 3.6 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 January 2026).

[81] CRTs are available on the CPUC's Affordability webpage. SCE's CRT has certain information labeled confidential. Current CRTs are for first quarter 2026 (Q1-2026) with current rates effective March 1, 2026 for all IOUs.

[82] Rates include the California Climate Credit (CCC) which functions as a revenue requirement reduction. D.26-04-036 took immediate action to move the large electric IOUs' residential CCC to August and September to provide maximum possible affordability relief when bills are highest. Rates are at class level and do not reflect rate design adjustments such as the Base Services Charge. PG&E and SDG&E CRT 2027 – 2029 sales forecasts held at currently authorized sales forecasts; Energy Division adjusted SCE CRT 2027 – 2029 sales forecasts to be held at currently authorized sales forecasts for consistency across IOUs. Energy Division staff modified the revenue requirements in the CRTs 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.

percentage change is divided by the number of years in the forecast period.[83] The forecasted year-end 2029 rates for PG&E, SCE, and SDG&E are projected to grow at slightly higher than inflation.[84]

- PG&E: about 14 percent through 2029 for an average annual increase of about 4 percent
- SCE: about 16 percent through 2029 for an average annual increase of about 4 percent
- SDG&E: about 25 percent through 2029 for an average annual increase of about 6 percent

Bundled Residential Bill Forecasts

Figure 8 shows the projected monthly bill increase resulting from the Table 7 rates forecast based on: 1) the usage amounts the IOUs use in their legal bill inserts[85] for a typical customer living in a *moderate* climate zone – 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–700 kWh per month for PG&E and SCE, and 500 kWh/month for SDG&E.[86] Average electricity bills for a customer living in one of these two climate zones are shown below.[87] All projected bill increases are greater than the assumed average annual rate of inflation of 3.2 percent except for PG&E CARE hot climate zone customers.[88]

[83] The average of year-over-year changes over this time period for PG&E, SCE, and SDG&E, respectively, are: 3.7 percent, 3.8 percent, and 5.9 percent.

[84] Inflation rate 2026 – 2029 is projected to increase 3.2 percent on an average annual basis. 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 January 2026).

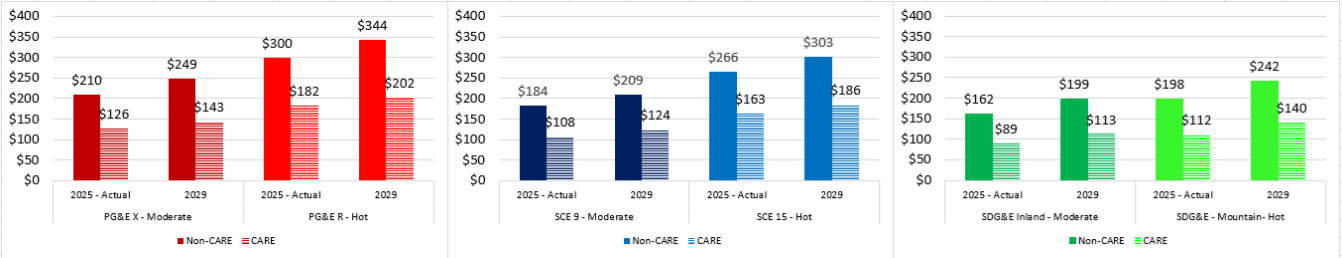
[85] In compliance with Rule 3.2(d) of the CPUC's Rules of Practice and Procedure, the IOUs are to provide notice of, among other things, proposed residential rate changes addressed in a utility's application. Bill impacts for a typical residential customer usually accompany these rate changes in a bill 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.

[86] "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. Hot climate zones are as defined in D.16-09-016. 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.

[87] Bill is averaged over the calendar year. SCE and SDG&E data includes the Base Services Charge (BSC). PG&E year-end 2025 data does not include the BSC as PG&E did not implement the BSC until Q1-2026; had PG&E year-end 2025 data reflected the BSC, year-end 2025 bills may have been be lower, particularly in hot climate zones. Bills are for illustrative purposes only.

[88] Inflation rate 2026 – 2029 is projected to increase 3.2 percent on an average annual basis. 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 January 2026).

Figure 8: PG&E, SCE, and SDG&E Current and Projected Residential Average Monthly Bills, Year-End 2025 – Year-End 2029 Typical Customer Living in a Moderate and Hot Climate Zone



Bundled Residential Energy Spending and Share-of-Wallet Forecasts

The Residential Energy Cost Calculator (RECC), originally developed as part of the CPUC's 2021 En Banc White Paper,[89] was used to forecast customer energy bills (electricity, natural gas, and gasoline) under a baseline rate scenario for a set example of households to show: 1) how the overall level of spending on energy will change over time and 2) what portion of an average household's annual energy spending, or share-of-wallet,[90] will go towards electricity, natural gas, and gasoline.[91] As in the 2021 En Banc White Paper, the updated RECC baseline scenario—now called the base case—for the period 2025–2029 does not reflect assumptions about future sales growth due to electrification nor consider how the impact of rising electric rates may affect cost-effectiveness for a customer looking to adopt an electric vehicle or electrify their home;[92] this type of analysis will be part of future editions of the SB 695 Report.

The updated RECC base case includes several refinements over the 2021 En Banc White Paper RECC (2021 RECC) baseline scenario as listed below.[93]

[89] *See* "Utility Costs and Affordability of the Grid of the Future."

[90] While not specifically called an energy share-of-wallet forecast in the 2021 En Banc White Paper, this type of total energy portioning (electricity, natural gas, and gasoline) has since become known as such.

[91] The 2021 En Banc White Paper RECC (2021 RECC) also showed comparisons between different customers and modeling assumptions.

[92] Results for 2025 are actual and 2026 — 2029 are forecasted. The base case is for a dual-fuel household with gasoline transportation fuel consumption and is agnostic regarding DERs; it does not incorporate, for example, assumptions about rooftop solar, electric vehicles, or heat pump technologies. Cap-and-Invest proceeds returned to residential customers via the California Climate Credit are fixed at 2026 values. Numbers may not sum due to rounding. Methodology for the base case is subject to change in future versions of the SB 695 Report as additional modeling to incorporate more features is added.

[93] *See* Appendix C for additional information about natural gas and gasoline assumptions..

- The updated RECC residential electric rate forecasts correspond to the data in Table 7 for a typical non-CARE and CARE customer in a moderate climate and a hot climate zone.[94] The 2021 RECC used RAR instead of non-CARE and CARE rates to produce electric bills; non-CARE and CARE rates are more realistic than using RAR to determine bills, as no customer is billed at RAR. The 2021 RECC produced electric bill data for all IOUs based on a PG&E hot climate zone; the updated RECC uses monthly usage data for IOU-specific moderate and hot climate zones as defined in Figure 8.
- The updated RECC residential natural gas rate forecasts for the three large gas IOUs—PG&E, SoCalGas, and SDG&E—are based on natural gas rates reported by the CEC in the 2025 CED forecast that forms part of the 2025 IEPR, rather than rates constructed from various sources as was done in the 2021 RECC. This simplifies the forecasting process as well as aligns it with the CED forecast, which is used as a "single forecast set" for certain planning work areas in the CEC and CPUC.
- Similar to the 2021 RECC model, the updated RECC model uses the same gasoline price forecast for all IOUs, based on an Energy Information Administration (EIA) forecast plus adjustments to calculate a total gasoline price; there are no refinements to this methodology, only an updating of the source data.

Updated RECC base case results for the period 2025–2029 show that average monthly energy bills for households are forecast to grow steadily through 2029 at slightly above the assumed rate of inflation.[95] Since base case energy usage is not assumed to change over time, all of the increase in costs is due to growth in electricity and natural gas rates and gasoline prices. In these forecasts, electricity bills rise more slowly than natural gas bills but faster than gasoline bills.[96] Figure 9, below, shows an example of the graphs that are available in Appendix C.[97]

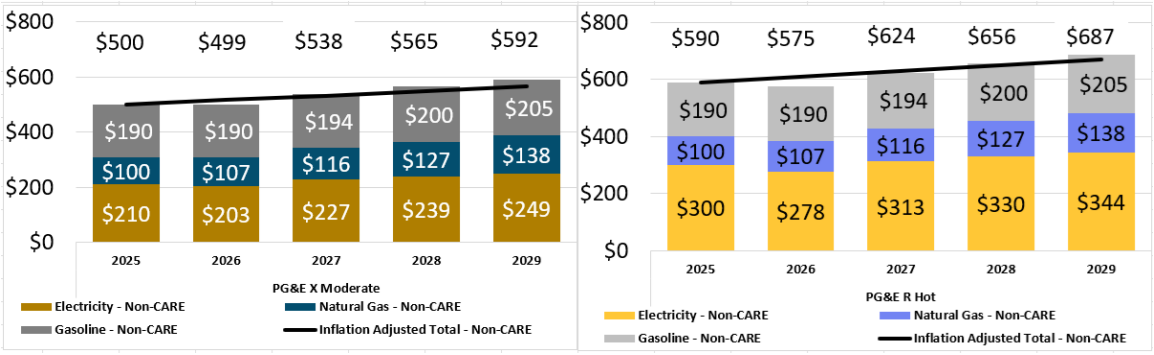
[94] The rate forecasts in Table 7 do not specifically integrate new and upgraded distribution grid costs, generally considered to be electrification costs, beyond the year 2026; 2027 - 2029 costs are accounted for as part of general distribution cost trends. Forecasted new and upgraded distribution grid costs may be broken out of general distribution cost trends when these costs are a more significant portion of revenue requirement.

[95] Inflation rate 2026 – 2029 is projected to increase 3.2 percent on an average annual basis. 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 January 2026).

[96] Gas bills rise about 2 percent year-over year; variance above this projected gasoline average annual increase could cause significantly different results.

[97] Data may not sum due to rounding.

Figure 9: PG&E Base Case Total Energy Cost and Energy Share-of-Wallet, Typical Non-CARE Customer, Moderate and Hot Climate Zones, (2025 Actual, 2026 – 2029 Forecasted)



Electrification of vehicles and/or building appliances can provide opportunities for California households to reduce their energy bills, particularly in high gasoline price scenarios. Future versions of the SB 695 Report will include more refinements to the base case electricity, natural gas, and gasoline forecasts, as well as integration of electrification scenarios with demand sensitivities e.g. high demand electrification.

IV. Natural Gas Revenue Requirements and Rate Trends

Changes to Utilities' Revenue Requirements

Overview

Bundled[98] gas rates are impacted by the following: 1) changes to revenue requirement, which are mostly determined in General Rate Cases (GRC)[99] 2) changes to how the revenue requirement is allocated among customer classes and forecasted sales demand, which are determined in cost allocation proceedings,[100] and 3) core procurement costs adjusted monthly through advice letters filed by the IOUs. The decisions of other

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

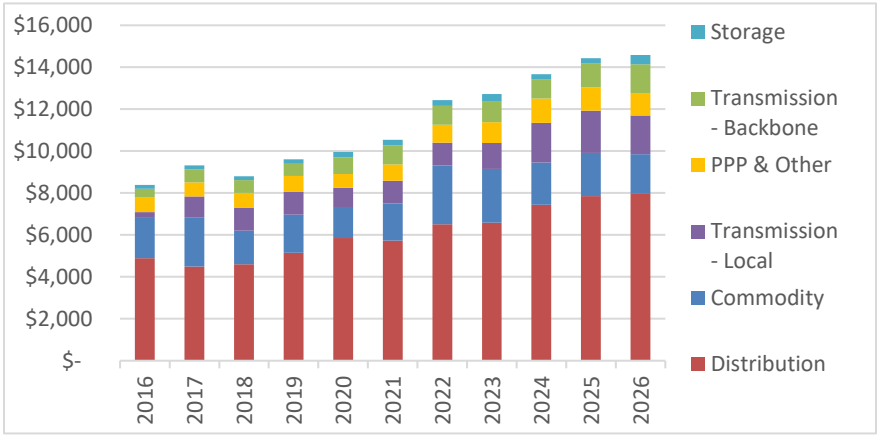
[99] Gas revenue requirements and rates can also be affected by non-GRC proceedings, such as: (1) advice letter filings dealing with leak abatement and (2) proceedings dealing with biomethane and renewable gas projects; cost of capital; and gas distribution, transmission and storage integrity management programs.

[100] As part of cost allocation proceedings, 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.

state and federal agencies can also impact rates.[101]

Revenue requirement trends across rate categories highlight the factors driving utility revenue.[102] From 2016 to 2026 the combined revenue requirement of California's three largest gas utilities has risen 74 percent, as shown in Figure 10. The largest gas utility driver has been the gas distribution revenue requirement, followed by the commodity revenue requirement, which fluctuates with wholesale gas markets.

Figure 10: SoCalGas, PG&E, and SDG&E Combined Gas Revenue Requirement by Rate Category (January 1, $ millions)



Gas customers are classified as core (residential and small commercial) and noncore (large commercial and industrial). Core customers receive gas procurement and delivery from the utilities, though some use third-party suppliers known as Core Transport Agents. Noncore customers buy gas from third parties[103] and rely on utilities only for delivery. The gas system is comprised of backbone transmission, local transmission, distribution, and storage. Backbone transmission uses large, high-pressure pipelines to move gas from receipt points on the California border to local transmission and distribution systems. Local transmission pipelines transport gas to the distribution systems, which deliver it to customers via small, lower-pressure pipelines. Transmission pipelines are costlier to build and operate, but the distribution systems cover more miles. California's three largest gas utilities operate 10,090 miles of intrastate transmission and 105,117 miles

[101] For example, 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.

[102] Storage, transmission, and distribution revenue requirements adopted in GRCs include operating costs, annualized capital depreciation costs, taxes, and authored return on rate base. Depreciation is amortized over an assets' useful life and therefore annual depreciation reflects only a portion of the total capital costs approved in general rate cases and other cost-recovery proceedings.

[103] Third parties: producers (extract gas from wells), marketers (buy/sell gas), and brokers (facilitate transactions between buyers and sellers).

of distribution pipelines,[104] with distribution costs mostly borne by core customers.[105] Storage is crucial for meeting peak demand, handling disruptions, and stabilizing prices. Utilities must maintain storage for core customers, while noncore customers purchase their own storage. The sections below detail recent utility-specific revenue requirement trends for commodity,[106] backbone transmission, distribution, storage, and public purpose program (PPP) costs.[107]

PG&E Revenue Requirement by Rate Category

PG&E's 2026 gas operations revenue requirement consists of various rate categories[108] that support 6,490 miles of gas transmission pipelines, 45,200 miles of gas distribution pipelines, and three gas storage facilities serving approximately 4.8 million gas meters from Bakersfield to the Oregon border.[109]

Figure 11: PG&E's (2026) $6,727 Million Revenue Requirement, Breakdown ($ millions/percentages) by Rate Category and 2016 - 2026 PG&E January 1 Gas Revenue Requirement by Rate Category ($ millions)[110]

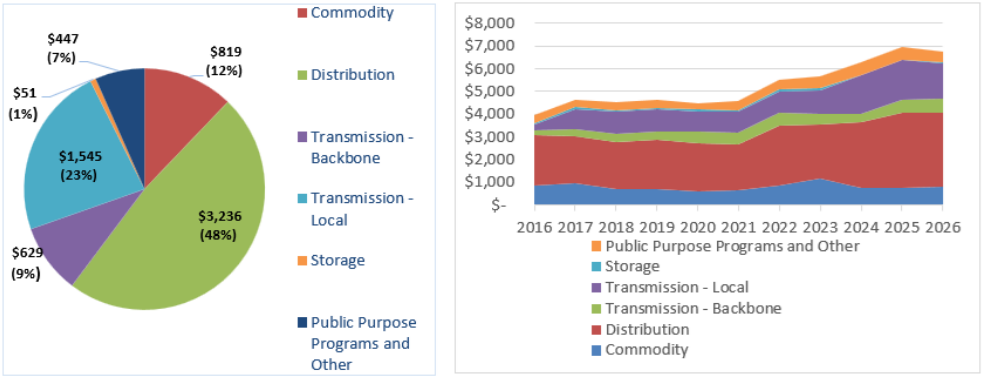


Figure 11 shows PG&E's 2026 gas operations revenue requirement is $6,727 million, a 70 percent increase since 2016, largely driven by infrastructure maintenance and compliance with state and federal pipeline safety regulations. However, it declined by $239 million or 3 percent from 2025 to 2026, driven by recovery of prior under-collections, a decline in PPP-related greenhouse gas costs, and reductions in the distribution

[104] Sources: 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); Exhibit PG&E-3 (Volume 1, Chapter 2, page 14) of Application 25-05-009 (PG&E 2027 GRC).

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

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

[107] *See* Appendix B for definitions of the costs that correspond to these revenue requirements.

[108] PG&E's distribution and local transmission costs are recovered through gas transportation rates. Core customers pay for allocated backbone transmission and storage – including storage obtained from independent storage operators – through the core gas procurement rate.

[109] Source: Exhibit PG&E-3 (Volume 1, Chapter 2, page 14-15) of Application 25-05-009 (PG&E 2027 GRC).

[110] Data are drawn from PG&E responses to Energy Division SB 695 Report data requests submitted to the CPUC in February 2026.

requirement following completion of wildfire-related cost recovery and a GRC-related adjustment. Additional declines reflect lower projected capital, financing, and operating costs for the Oakland General Office.

SoCalGas Revenue Requirement by Rate Category

SoCalGas' 2026 revenue requirement includes multiple rate categories that fund approximately 3,385 miles of transmission pipelines, 51,670 miles of distribution pipelines, and four storage facilities, serving about 5.9 million meters across roughly 24,000 square miles from Visalia to the Mexico-U.S. border and the California-Nevada border.[111]

Figure 12: SoCalGas' (2026) $6,827 Million Revenue Requirement, Breakdown ($millions/percentages) by Rate Category[112] and 2016–2026 SoCalGas January 1 Revenue Requirement by Rate Category ($ millions)[113]

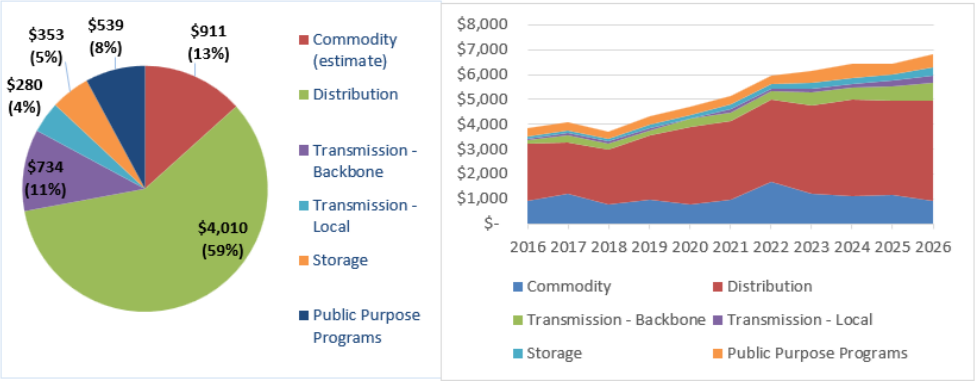


Figure 12 shows SoCalGas' 2026 revenue requirement is $6,827 million, representing an 84 percent increase since 2016, and a $371 million or 6 percent increase from 2025, driven by several offsetting factors.[114] Two major increases – the incremental revenue requirement authorized in Sempra's 2024 GRC and the 18-month recovery of a GRC Memorandum Account balance – are partially offset by the conclusion of the Transmission Integrity Management Program Balancing Account (TIMPBA) under-collection recovery. Attrition and cost of capital adjustments were largely offset by a decrease in balancing accounts.

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

[112] Data are drawn from SoCalGas responses to Energy Division SB 695 Report data requests submitted to the CPUC in February through March of 2026. Values may be affected by rounding.

[113] Data are from IOU responses to Energy Division SB 695 Report data requests, submitted to the CPUC in February and March 2026. Data may be affected by rounding.

[114] This is a non-exhaustive list of factors.

SDG&E Revenue Requirement by Rate Category

SDG&E's 2026 revenue requirement supports operation of approximately 215 miles of transmission pipelines and 8,247 miles of distribution pipelines, serving roughly 900,000 meters across 1,400 square miles from Orange County to the Mexico-U.S. border.[115]

Figure 13: SDG&E (2026) $1,025 Million Revenue Requirement Breakdown ($ millions/percentages) by Rate Category and 2016-2026 SDG&E January 1 Gas Revenue Requirement by Rate Category ($ millions)

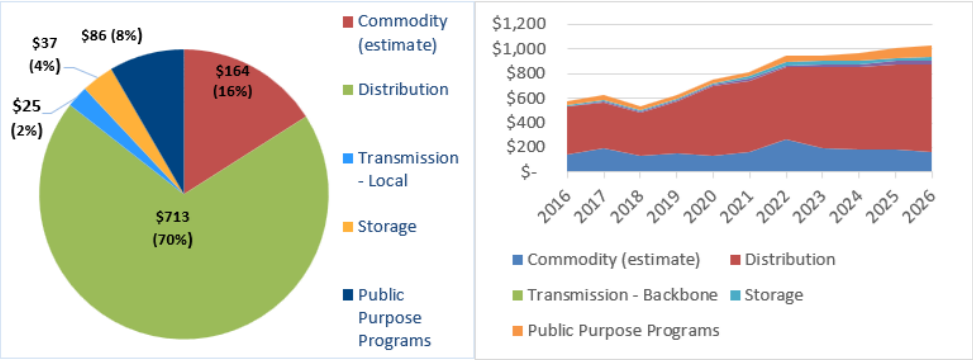


Figure 13 shows that SDG&E's 2026 gas operations revenue requirement is $1,025 million, up 77 percent since 2016, and increased $19 million or 2 percent, from 2025, driven by an increase from the 2024 GRC and an 18-month recovery of the General Rate Case Memorandum Account (GRCMA) balance,[116] partially offset by amortization adjustments, a net decrease from balancing account and regulatory updates (including attrition, greenhouse gas costs, cost of capital, and leak abatement[117] changes), and the conclusion of the Transmission Integrity Management Program Balancing Account TIMPBA under-collection recovery.[118]

Average Rates by Customer Class

In 2026, PG&E's customer classes experienced lower average rates compared with 2025.
From 2016 through 2025, average rates for PG&E's customer classes generally trended upward. SoCalGas' large commercial and industrial customer class has generally experienced upward-treading average rates since 2016. Other SoCalGas customer classes saw mostly upward-trending average rates from 2016 to 2022, downward-trending average rates from 2022 to 2025 due to a declining average procurement rate, and an increase in 2026. SDG&E's customer classes also experienced mostly upward-trending average rates from

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

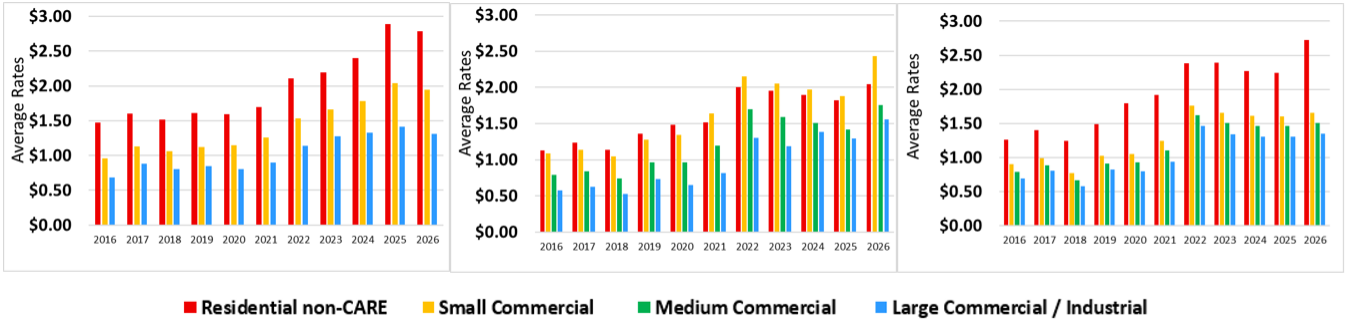
[116] *See* AL 3392-G-A/G-B, pages 3, which includes the 18- month recovery period from February 1, 2025, through July 31, 2026.

[117] *See* AL 3484-G.

[118] This is a non-exhaustive list of factors.

2016 to 2022, downward-trending average gas rates from 2022 to 2025 due to a decreasing average procurement rate, and an increase in 2026.

Figure 14: PG&E (left), SoCalGas (middle), and SDG&E (right) Average per Therm Rates[119] by Customer Class in Effect January 1 (2016-2026)



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

Appendix A – 2026 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 2026 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 "2026 Electric and Gas Costs Utility Reports" bullet point under "Reports and White Papers" section of the webpage.

Appendix B – Glossary of Key Ratemaking Terms

The following is a list of essential definitions used in this document and in the CPUC's ratesetting work in GRC Phase I, GRC Phase II proceedings, and other ratesetting 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.
- **California Climate Credit:** A credit that appears on customer bills twice a year to residential electric customers (and certain qualifying small business electric customers) and once a year to residential gas customers for allocated allowances sold annually under the Cap-and-Invest Program.
- **Competition Transition Charge (CTC) Costs:** Charges to recover above-market costs associated with power purchase contract obligations that resulted from electric industry restructuring pursuant to Public Utilities Code Section 367(a).
- **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.
- **Distribution Integrity Management Program (DIMP):** 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.
- **Distributed Energy Resources (DER):** Distribution-connected generation resources, including energy efficiency, storage, electric vehicles, and demand response technologies.
- **Electric Bill Generation Rate:** This rate component collects the cost of: 1) Utility Owned Generation (see separately); 2) purchased power (see separately); 3) certain programs such as the Renewables Portfolio Standard program; and 4) generation capacity costs to ensure energy is available on demand.

- **Electric Bill Distribution Rate:** This rate component collects the operating and capital costs to distribute power and includes certain wildfire mitigation costs as well as certain funding related to specific public policy objectives such as transportation electrification and demand response.
- **Electric Bill Transmission Rate:** Transmission rates, primarily set by the Federal Energy Regulatory Commission (FERC) that collect: 1) costs associated with transmission assets under California Independent System Operator operational control and subject to FERC's jurisdiction, net of revenues that flow to transmission owners from others' use of the transmission system; 2) Reliability Services (see separately); and 3) the Transmission Access Charge Balancing Account Adjustment (see separately).
- **Electric Bill Other Rates:** Other rates that appear on an electric bill besides generation, distribution, and transmission for costs such as (see separately): 1) Public Purpose Programs funding; 2) New System Generation charges; 3) Competition Transition Charges; 4) Nuclear Decommissioning; 5) Wildfire Fund charges; and 6) Securitization fixed recovery charges.
- **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, including the cost of above-market costs associated with power purchase contract obligations; ERRA costs are pass-through expenses–the utility receives no markup 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.
- **Gas Backbone Transmission Costs:** Costs include depreciated capital expenditures, operations and maintenance (O&M) costs, and administrative and general (A&G) costs as well as the federally mandated Transmission Integrity Management Program and state-mandated Pipeline Safety Enhancement Plan costs.
- **Gas Commodity Costs:** Costs 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.
- **Gas Distribution Costs:** 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.
- **Gas Local Transmission Costs:** Costs include depreciated capital expenditures, O&M costs, and A&G costs recovered for local transmission pipelines, including Transmission Integrity Management Program and state-mandated Pipeline Safety Enhancement Plan costs.
- **Gas Storage Costs:** 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.
- **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…"

- **Greenhouse Gas (GHG) Costs:** Entities covered under the Cap-and-Invest Program, including utilities, must obtain and surrender to the California Air Resources Board (CARB) allowances or offsets for specified greenhouse gas emissions.
- **Greenhouse Gas (GHG) Revenue Return:** The amount available from the sale of IOU-allocated allowances to be returned to ratepayers in the form of a bill credit, principally through the California Climate Credit.
- **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.
- **New System Generation (NSG) Costs:** Charges to recover the costs of "new generation" assets the IOUs procure to maintain system reliability.
- **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.
- **Nuclear Decommissioning (ND) Costs:** Costs that flow into a trust maintained for assurance that complete decommissioning activities for nuclear facilities will be undertaken.
- **Power Charge Indifference Adjustment (PCIA):** A rate component intended to equalize cost sharing between departed load and bundled load.
- **Purchased Power Costs:** Wholesale market and contract costs with third-party electricity generators, including the Power Charge Indifference Adjustment (PCIA) which covers the legacy cost of generation that was secured while bundled and unbundled customers were served by the IOU.
- **Public Purpose Programs (PPP) Costs:** Program funding authorized for Energy Efficiency programs, Low-Income programs, and other public policy programs; gas programs include the gas public interest research and development program administered by the California Energy Commission (CEC).
- **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.

- **Reliability Services Costs:** Costs related to contracts signed by the California Independent System Operator with certain generators needed to maintain system reliability.
- **Revenue Requirement:** 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.
- **Storage Integrity Management Program (SIMP):** 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.
- **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.
- **Transmission Access Charge (TAC) Balancing Account Adjustment:** Accounts for the over- or under-collection of what an 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.
- **Transmission Integrity Management Program (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.
- **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.
- **Utility Owned Generation (UOG) Costs:** Fuel and other operating costs as well capital costs associated with generation plants such as nuclear, gas, and hydroelectric.
- **Wildfire Fund Charge (WFC):** Charges collected from non-exempt ratepayers to fund the wildfire fund created by Assembly Bill (AB) 1054 (Holden, 2019) starting in October 2020
- **Wildfire Mitigation Costs:** Expenditures to reduce wildfire risk, including vegetation management, and grid hardening.

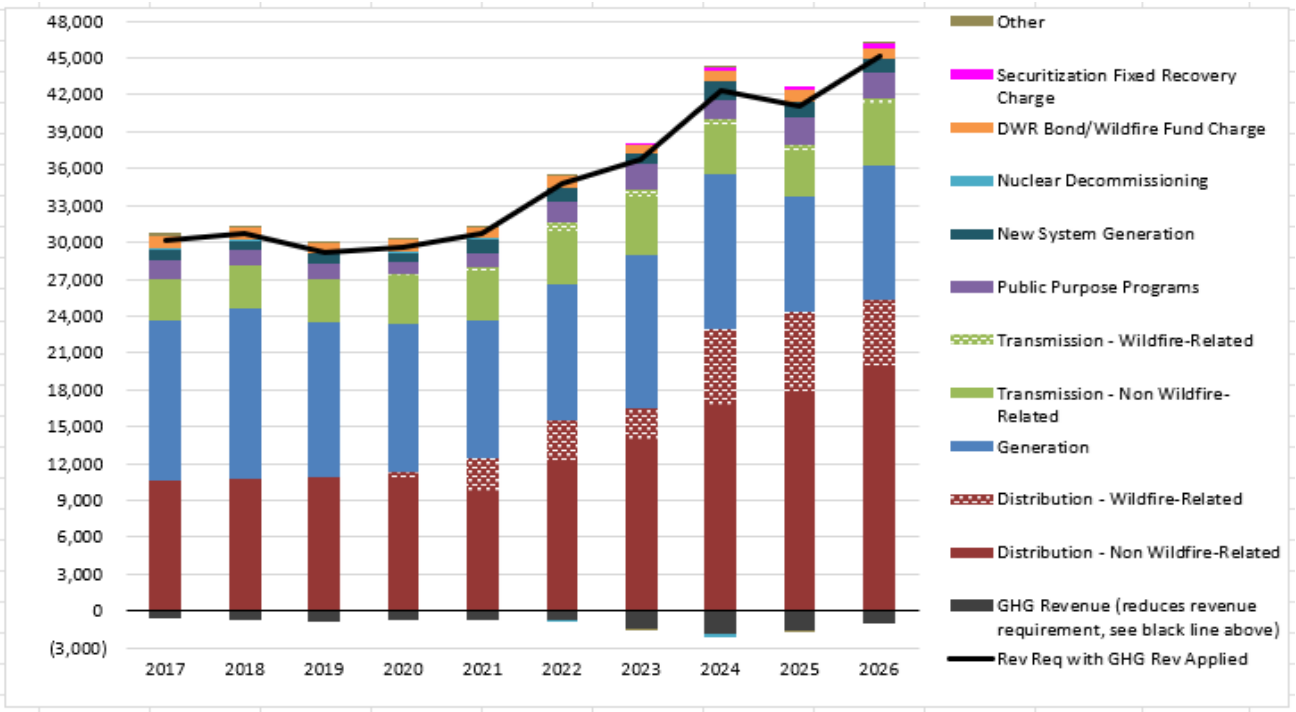
- **Wildfire Mitigation Plan (WMP):** Electric utilities are required to prepare and submit a WMP to the Office of Energy Infrastructure Safety (Energy Safety) every three years which describes the level of wildfire risk in their service territories and how they intend to address those risks.
- **Wildfire Liability Costs:** Expenditures to facilitate a response to wildfires, including the Wildfire Fund Charge, wildfire insurance premium costs to cover claims paid as a result of property losses, and costs related to recovering from catastrophic events.
- **Wildfire Securitization Fixed Recovery Charges** (**FRC)**: Certain wildfire costs that AB 1054 permits to be securitized through a financing order collected from non-exempt ratepayers, rather than being financed through the more traditional unsecured bond offerings. This line item must be shown separately on customer bills.

Appendix C – Supporting Data

C-1: PG&E, SCE, and SDG&E Bundled System Average Rate (January 1, cents/kWh)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
PG&E	18.8	19.2	19.6	21.6	22.6	25.1	28.6	36.6	35.0	33.4
SCE	15.9	16.3	15.9	16.4	18.5	22.3	25.2	26.9	26.4	28.3
SDG&E	21.8	24.0	23.7	24.1	24.0	31.1	38.5	31.5	33.3	39.3

C-2: PG&E, SCE, and SDG&E Combined Authorized Electric Revenue Requirement, by Functional Category (January 1, $ Millions)



C-3: Revenue Requirement Reductions that Resulted in a Year-Over-Year Bundled System Average Rate Decrease (January 1)

Reductions in revenue requirement (largest decreases cited)	Revenue requirement increases on January 1 were offset by reductions in revenue requirement which resulted in a net rate decrease for the indicated year-over-year period			
	2023	2024	2025	2026
PG&E				
Removal from rates in 2024 of a large revenue requirement corresponding to: 1) wildfire mitigation activities in PG&E's 2022 Wildfire Mitigation and Catastrophic Events (WMCE) proceeding and 2) certain costs related to purchasing electricity as part of PG&E's 2023 Energy Resource Recovery Account (ERRA) Trigger proceeding.[120]		✓	✓	
Removal from rates in 2025 of a large revenue requirement corresponding to: 1) wildfire mitigation activities in PG&E's 2021 WMCE proceeding and 2) the Intermittent Rate Relief (IRR) portion of the Wildfire Gas and Safety Costs (WGSC).			✓	✓
A revenue requirement reduction in 2026 to reflect amortization of certain costs related to purchasing electricity as part of PG&E's 2025 ERRA Trigger proceeding.[121]			✓	✓
SCE				
The removal from rates in 2024 of: a large revenue requirement corresponding to: 1) wildfire liability costs in SCE's Wildfire Expense Memorandum Account (WEMA) 2 proceeding and 2) certain costs related to purchasing electricity as part of SCE's 2023 ERRA Trigger proceeding.[122]		✓	✓	
A revenue requirement reduction in 2025 to reflect amortization of certain costs related to purchasing electricity as part of SCE's 2024		✓	✓	

[120] An ERRA "trigger" mechanism allows for the utility to file an expedited application requesting an adjustment to rates, if the ERRA balance reaches 4 percent in excess of prior year's annual fuel and power purchase costs. The 2023 ERRA Trigger proceeding was consolidated with the 2024 ERRA Forecast proceeding. The under-collected ERRA balance associated with the 2023 ERRA Trigger was in rates from January 1, 2024 to June 30, 2024, after which the revenue requirement was removed from rates.

[121] The 2025 ERRA Trigger proceeding was consolidated with the 2026 ERRA Forecast proceeding. PG&E amortized the over-collected (i.e., to be returned to ratepayers) ERRA balance associated with the 2025 ERRA Trigger by transferring it to a Portfolio Allocation Balancing Account (PABA) subaccount for implementation in rates on January 1, 2026.

[122] The under-collected ERRA balance associated with the 2023 ERRA Trigger was in rates from June 1, 2023 to May 31, 2024, after which the revenue requirement was removed from rates.

Reductions in revenue requirement (largest decreases cited)	Revenue requirement increases on January 1 were offset by reductions in revenue requirement which resulted in a net rate decrease for the indicated year-over-year period			
	2023	2024	2025	2026
ERRA Trigger proceeding.[123]				
A lower-than-expected bundled SAR in 2025 due to its GRC not implementing on January 1, 2025. While not a revenue requirement reduction on January 1, the expected revenue increase did not occur.[124]		✓	✓	
SDG&E				
A lower-than-expected bundled SAR in 2024 due to its GRC not implementing on January 1, 2024. While not a revenue requirement reduction on January 1, the expected revenue increase did not occur.[125]	✓	✓		

[123] SCE amortized the over-collected (i.e. to be returned to ratepayers) ERRA balance associated with the 2024 ERRA Trigger from October 1, 2024 to September 30, 2025.

[124] SCE's 2025 GRC implemented on October 1, 2025.

[125] While there was not a January 1, 2024 to January 1, 2025 bundled SAR decrease, the January 1, 2025 revenue increase resulting from GRC implementation also did not occur. D.24-12-074 approved SDG&E's GRC on December 19, 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.

C-4: Total Wildfire-Related Authorized Costs and Revenue Requirements
(January 1, 2020 to January 1, 2026, $ Billions)

	Authorized Costs			Authorized Revenue Requirements		
	(A)	(B)	(C)	(D)	(E)	(F)
Utility	Total Wildfire Mitigation Authorized Costs	Total Wildfire Liability Authorized Costs	**Total Wildfire-Related Authorized Costs (A) + (B)**	Total Wildfire Mitigation Authorized Revenue Requirement	Total Wildfire Liability Authorized Revenue Requirement	**Total Wildfire-Related Authorized Revenue Requirement (D) + (E)**
PG&E	$24.9	$7.4	**$32.3**	$15.5	$6.9	**$22.4**
SCE	$12.2	$5.9	**$18.1**	$5.9	$6.1	**$12.0**
SDG&E	$1.9	$1.6	**$3.5**	$1.3	$1.7	**$3.0**
Total	**$39.0**	**$14.9**	**$53.9**	**$22.7**	**$14.7**	**$37.4**

C-5: PG&E Wildfire-Related Revenue Requirement by Distribution, Transmission, and Non-Bypassable Charge Rate Components, by Operating Expense and Capital Expense (January 1, $ millions)

PG&E January 1 Revenue Requirement		Wildfire-Related Distribution	Wildfire Fund NBC	Wildfire-Related FRC NBC	Wildfire-Related Transmission	Subtotal Wildfire-Related Rev Req	Total Wildfire Related Rev Req	Total Rev Req	% Wildfire-Related Rev Req to Total Rev Req
2019	OpEx	0.0	0.0	0.0	0.0	0.0	0.0	13,145.7	0%
	CapEx	0.0	0.0	0.0	0.0	0.0			
2020	OpEx	275.5	0.0	0.0	16.0	291.5	315.9	13,921.0	2%
	CapEx	22.9	0.0	0.0	1.5	24.4			
2021	OpEx	1,985.3	403.4	0.0	138.4	2,527.1	2,527.9	13,839.1	18%
	CapEx	-14.6	0.0	0.0	15.4	0.8			
2022	OpEx	2,411.2	457.0	0.0	381.9	3,250.1	3,370.7	15,754.8	21%
	CapEx	-35.4	0.0	82.3	73.7	120.6			
2023	OpEx	1,180.7	378.3	0.0	414.4	1,973.4	2,232.6	15,619.1	14%
	CapEx	5.4	0.0	208.5	45.3	259.2			
2024	OpEx	4,225.7	393.1	0.0	263.0	4,881.8	5,361.1	20,710.6	26%
	CapEx	279.0	0.0	146.3	54.0	479.3			
2025	OpEx	3,425.5	412.6	0.0	317.6	4,155.7	4,790.5	19,285.9	25%
	CapEx	290.7	0.0	293.2	50.9	634.8			
2026	OpEx	2,300.6	401.8	0.0	41.2	2,743.6	3,781.1	20,456.6	18%
	CapEx	542.3	0.0	194.0	301.2	1,037.5			

C-6: SCE Wildfire-Related Revenue Requirement by Distribution, Transmission, and Non-Bypassable Charge Rate Components, by Operating Expense and Capital Expense (January 1, $ millions)

SCE January 1 Revenue Requirement		Wildfire-Related Distribution	Wildfire Fund NBC	Wildfire-Related FRC NBC	Wildfire-Related Transmission	Subtotal Wildfire-Related Rev Req	Total Wildfire-Related Rev Req	Total Rev Req	% Wildfire-Related Rev Req to Total Rev Req
2019	OpEx	0.0	0.0	0.0	0.0	0.0	0.0	11,879.8	0%
	CapEx	0.0	0.0	0.0	0.0	0.0			
2020	OpEx	157.1	0.0	0.0	168.2	325.3	325.9	11,484.4	3%
	CapEx	0.0	0.0	0.0	0.6	0.6			
2021	OpEx	574.6	422.7	0.0	168.2	1,165.5	1,209.7	12,665.3	10%
	CapEx	43.6	0.0	0.0	0.6	44.2			
2022	OpEx	606.7	441.9	0.0	146.8	1,195.4	1,300.7	14,768.9	9%
	CapEx	85.9	0.0	19.3	0.1	105.3			
2023	OpEx	910.2	402.3	0.0	119.0	1,431.5	1,685.3	16,680.2	10%
	CapEx	202.7	0.0	51.0	0.1	253.8			
2024	OpEx	1,088.8	408.9	0.0	127.5	1,625.2	2,037.2	17,675.0	12%
	CapEx	305.7	0.0	106.2	0.1	412.0			
2025	OpEx	1,546.1	416.8	0.0	76.3	2,039.2	2,745.0	17,596.3	16%
	CapEx	599.4	0.0	106.2	0.2	705.8			
2026	OpEx	1,026.3	426.4	0.0	71.9	1,524.6	2,769.4	19,784.1	14%
	CapEx	1,016.2	0.0	228.2	0.4	1,244.8			

C-7: SDG&E Wildfire-Related Revenue Requirement by Distribution, Transmission, and Non-Bypassable Charge Rate Components, by Operating Expense and Capital Expense (January 1, $ millions)

SDG&E January 1 Revenue Requirement		Wildfire-Related Distribution	Wildfire Fund NBC	Wildfire-Related 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	0.0	0.0	0.0	0.0	0.0	0.0	4,125.6	0%
	CapEx	0.0	0.0	0.0	0.0	0.0			
2020	OpEx	129.0	0.0	0.0	18.3	147.3	184.7	4,131.6	4%
	CapEx	37.4	0.0	0.0	0.0	37.4			
2021	OpEx	129.0	89.2	0.0	23.6	241.8	279.2	4,142.0	7%
	CapEx	37.4	0.0	0.0	0.0	37.4			
2022	OpEx	232.6	84.7	0.0	30.0	347.3	397.4	4,318.6	9%
	CapEx	50.1	0.0	0.0	0.0	50.1			
2023	OpEx	234.5	75.5	0.0	38.7	348.7	401.8	4,376.5	9%
	CapEx	53.1	0.0	0.0	0.0	53.1			
2024	OpEx	223.4	84.7	0.0	41.6	349.7	402.8	3,899.8	10%
	CapEx	53.1	0.0	0.0	0.0	53.1			
2025	OpEx	395.8	84.7	0.0	41.6	522.1	657.1	4,233.1	16%
	CapEx	135.0	0.0	0.0	0.0	135.0			
2026	OpEx	515.7	88.5	0.0	40.7	644.9	691.7	4,935.0	14%
	CapEx	46.8	0.0	0.0	0.0	46.8			

C-8: Electric Proceedings Wildfire-Related Revenue Requirement Removed from Rates, By Amortization End Date (Removal Excludes Ongoing Capital-Related Revenue Requirement)[126]

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				
2020-2022 VMBA/WMBA Undercollection Threshold[127]	D.20-12-005	1/1/2024	-$378	-$3
2022 WMCE (IRR)	D.23-06-004	7/1/2024	-$1,104	-$9
2021 WMCE Non-VMBA	D.23-08-027	9/1/2025	-$872	-$7
Wildfire and Gas Safety Cost (IRR)	D.24-03-006	9/1/2025	-$415	-$3
2023 WMCE (IRR)	D.24-09-003	3/1/2026	-$752	-$6
2021 WMCE VMBA	D.24-12-075	3/1/2026	-$503	-$4
2023 WMCE	D.26-02-004	3/1/2027	-$786	-$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	-$401	-$4
2021 WM/VM	D.24-03-008	6/1/2025	-$379	-$3
2019-2023 WRMBA Undercollection Threshold[128]	D.21-08-036	10/1/2025	-$129	-$1
2021 GRC Track 3	D.22-06-032	10/1/2025	-$385	-$3
2022 CEMA	D.24-05-037	10/1/2025	-$288	-$3

[126] Table does not include: 1) wildfire-related securitizations, the revenue requirements of which will begin to be removed from rates starting in 2031 and going through 2050 and 2) wildfire-related revenue requirements embedded in GRC revenue requirement implementations. 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 this table, other generally smaller wildfire-related revenue requirements may have been removed from rates as the result of advice letter dispositions. Bill impact is calculated using each utility's Cost and Rate Tracker at time of amortization end date (or with most recently posted version, if amortization has not yet ended) with revenue requirement impact in this table. Bill impact is rounded to closest dollar.

[127] Reflects Vegetation Management Balancing Account (VMBA) and Wildfire Mitigation Balancing Account (WMBA) revenue requirements below a specified threshold pursuant to PG&E's 2020 GRC Decision, approved by Advice Letter (AL). The 2020, 2021, and 2022 VMBA/WMBA AL amounts were removed from rates over the period 2022 – 2024.

[128] Reflects Wildfire Risk Mitigation Balancing Account (WRMBA) revenue requirement below a specified threshold pursuant to SCE's 2021 GRC Decision, approved by AL.

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
2022 WM/VM (IRR)	D.24-07-012	1/1/2026	-$210	-$2
2021-2024 VMBA Undercollection Threshold[129]	D.21-08-036	Various	-$129	-$1
2017 Thomas Fire - CEMA	D.25-01-042	6/1/2026	-$35	less than -$1
2022 WM/VM	D.25-06-051	10/1/2026	-$137	-$1
2023 WMCE	D.25-06-017	10/1/2026	-$416	-$4
SDG&E				
2024 GRC Track 2	D.24-02-010	2/1/2025	-$241	-$7
CEMA	D.24-07-013	10/1/2025	-$31	-$1
2024 GRC Track 2	D.24-02-010	1/1/2026	-$100	-$3
TTBA	D.24-06-003	2/1/2027	-$70	-$2
2024 GRC Track 2[130]	D.26-01-021	4/1/2029	$177	-$5

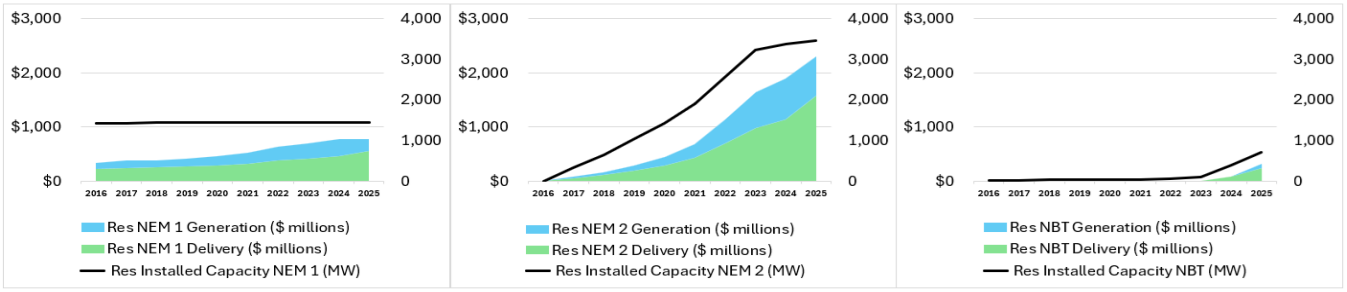
[129] Reflects VMBA revenue requirement below a specified threshold pursuant to SCE's 2021 GRC Decision, approved by AL. The 2021, 2022, and 2023 VMBA AL amounts totaling approximately $90 million were removed from rates over the period 2023 – 2025. The 2024 VMBA AL amount totaling approximately $39 million will be removed from rates in 2026.

[130] Corresponds to the 2019 through 2025 undercollected revenue requirement. SDG&E is to recover the balance of the undercollected revenue requirement for years 2026 and 2027 via a Tier 2 advice letter.

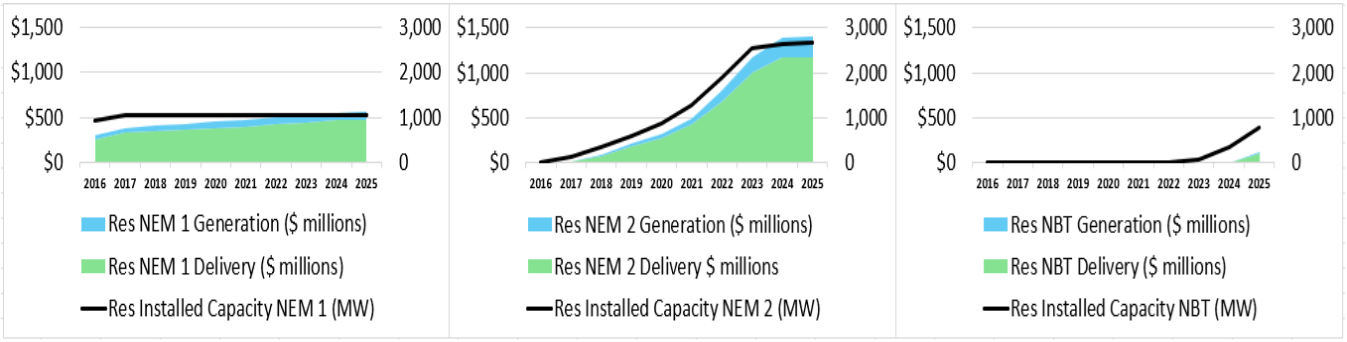
C-9: Total Electrification-Driven Authorized Costs and Revenue Requirements
(January 1, 2025 and January 1, 2026, $ Millions)

			Authorized Costs			Authorized Revenue Requirements
	(A)	(B)	(C)	(D)	(E)	(F)
Utility	Total New and Upgraded Distribution Capacity Authorized Costs	Total Electrification Programs Authorized Costs	**Total Electrification -Driven Authorized Costs (A) + (B)**	Total New and Upgraded Distribution Capacity Authorized Revenue Requirement	Total Electrification Programs Authorized Revenue Requirement	**Total Electrification -Driven Authorized Revenue Requirement (D) + (E)**
PG&E	$2,408.1	$70.4	**$2,478.5**	$436.3	$10.0	**$446.3**
SCE	$790.1	$366.7	**$1,156.8**	$38.4	$198.6	**$237.0**
SDG&E	$123.6	$380.0	**$503.6**	$3.3	$34.7	**$38.0**
Total	**$3,321.8**	**$817.1**	**$4,138.9**	**$478.0**	**$243.3**	**$721.3**

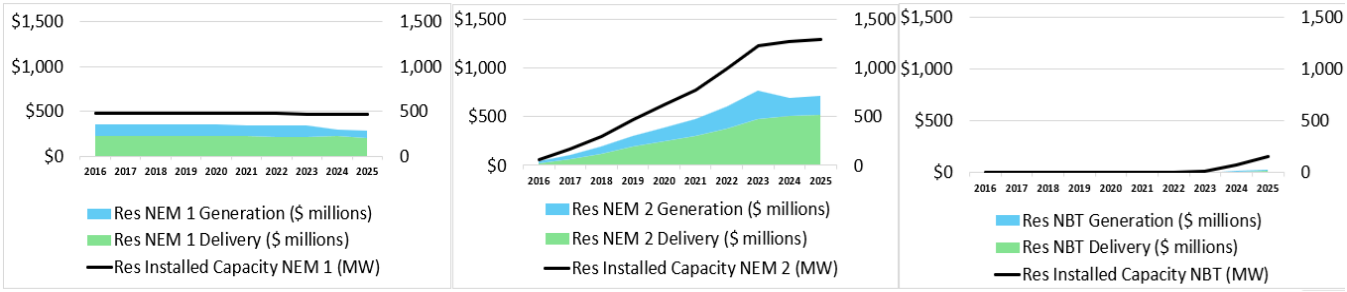
C-10: PG&E Residential NEM 1.0, NEM 2.0, and NBT Cost Shifts ($ Millions) Compared with Residential Installed Capacity (MW)[131]



C-11 SCE Residential NEM 1.0, NEM 2.0, and NBT Cost Shifts ($ Millions) Compared with Residential Installed Capacity (MW)



C-12: SDG&E Residential NEM 1.0, NEM 2.0, and NBT Cost Shifts ($ Millions) Compared with Residential Installed Capacity (MW)

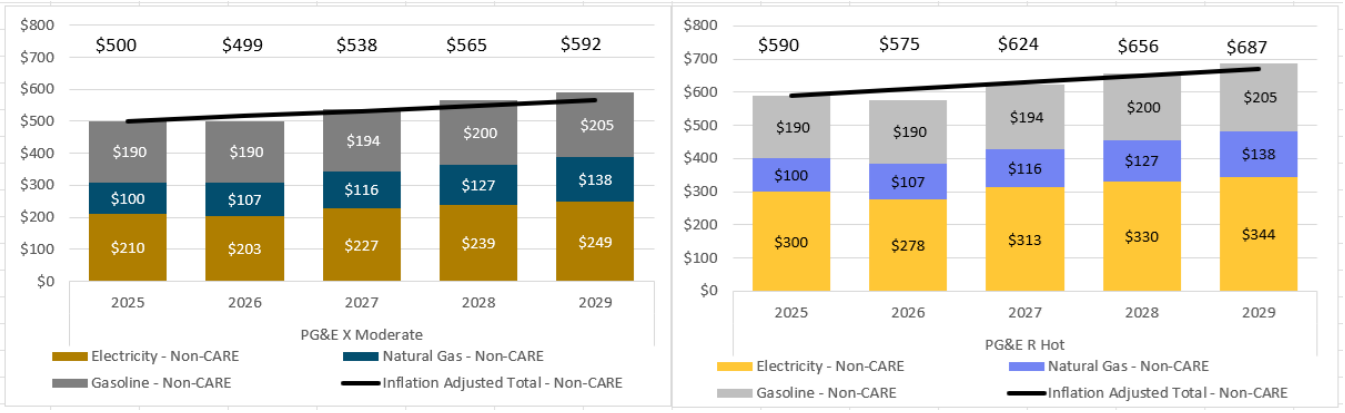


[131] There was a change in PG&E cost shift modeling between 2024 and 2025. The 2024 model generally used a top down approach of calculating the total cost shift and then portioning it out to customer classes and rate components. In the 2025 model, PG&E uses a more granular approach that entails many calculations at a fine resolution before adding the results together to get the total cost shift. For example, in the 2025 model, solar generation profiles are modeled hourly using PVWatts at a central site in each climate zone, which results in more granular capacity factor data rather than a single, fixed capacity factor across the service territory. PG&E also specifically models storage, both paired and unpaired. From 2024 to 2025, PG&E total NEM/NBT cost shift data across all customers increased by about 9 percent due to incremental capacity and another 10 percent due to updated capacity factor assumptions. The remaining 3 percent difference is attributable to a combination of changing rates and avoided costs.

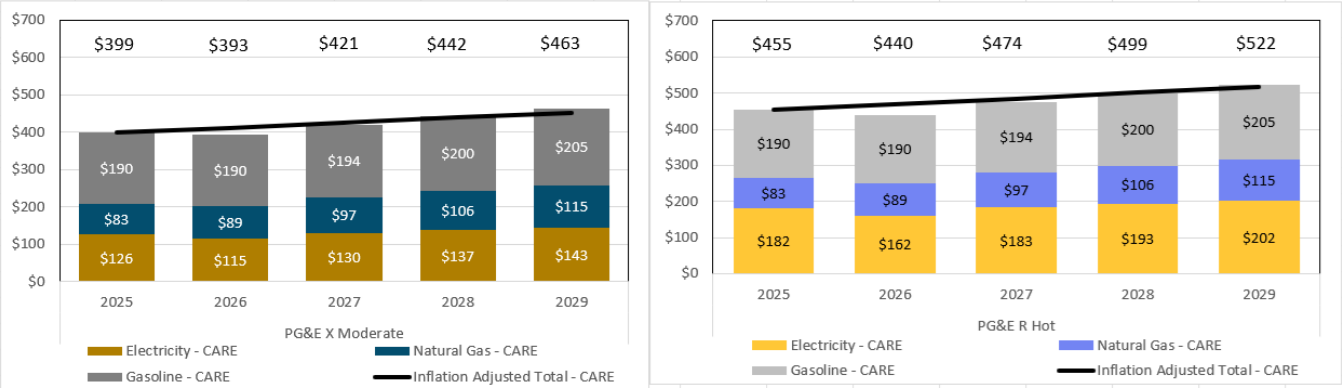
C-13: Residential Energy Cost Calculator Natural Gas and Gasoline Assumptions

Commodity	Assumptions
Natural Gas	See Form 2.3 in "CED 2025 Baseline Natural Gas Forecast" in the 2025 IEPR Demand Forecast docket; rates in $2024 used for Form 2.3 are converted to 2025 – 2029 values using a 3 percent inflation assumption. The CEC natural gas rates do not distinguish between Non-CARE and CARE; in the updated RECC, the CARE rate is set at the CEC rate , as CEC 2024 actual rates are better aligned with PG&E and SoCalGas 2024 actual rates as shown in the IOU rate change advisories. Natural gas rates are the same for moderate and hot climate zones without regard for baseline quantities that provide a minimum supply of natural gas at a lower cost. Monthly usage data to calculate bills is for typical customer shown in legal bill inserts for each IOU's currently authorized GRC: PG&E 2023 GRC 33 therms/month, SoCalGas 2024 GRC 36 therms/month and is the same for moderate and hot climate zones; SDG&E 2024 GRC 24 therms/month.
Gasoline	See EIA 2025 Annual Energy Outlook Table 57.9 (release date April 2025), Motor Gasoline End-User Price for base forecast which is then adjusted by subtracting $0.11/gallon Energy Tax/Allowance Fee for each year. The adjusted amount, in $2024, is then converted to 2025 – 2029 values using a 3 percent inflation assumption. Cap-and-Invest and Low Carbon Fuel Standard fees (average 2025 amounts of $0.23/gallon and $0.15/gallon, respectively, escalated at 3 percent inflation) based on CEC Estimated Gasoline and Price Breakdown Margins are then added to get the total gasoline price. Household gasoline usage assumes one personal vehicle driven 12,730 miles per year (see California Air Resources Board (CARB) EMFAC2025 v2.0.0 Statewide 2025 Annual VMT By Vehicle And Fuel Type) with a fuel economy of 24 miles per gallon (see CARB 2000 - 2021 GHG Inventory Trends Report, Figure 8, where "Vehicle Fuel Economy" is the average mpg for all gasoline passenger cars, trucks, and SUVs in California.

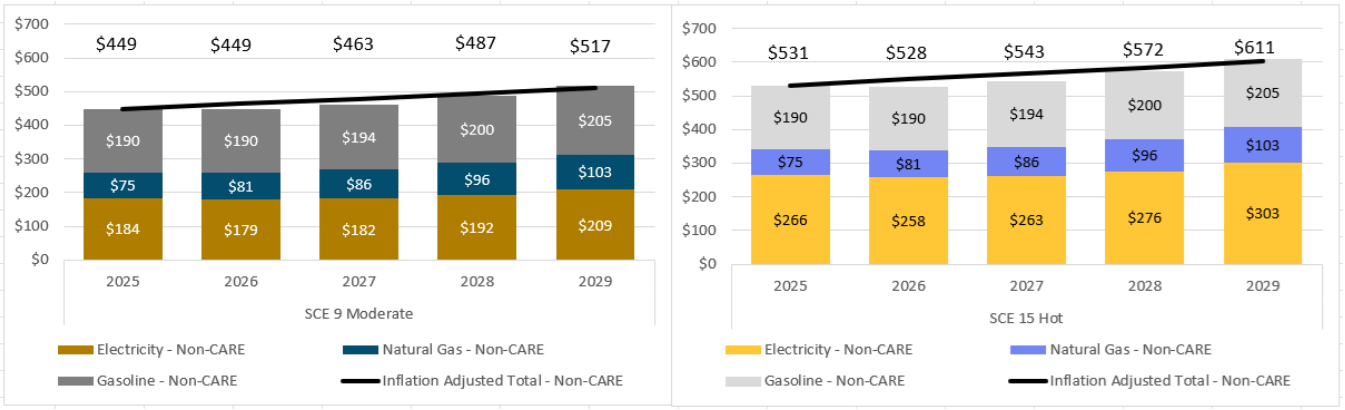
C-14: PG&E Base Case Total Energy Cost and Energy Share-of-Wallet, Typical Non-CARE Customer, Moderate and Hot Climate Zones, (2025 Actual, 2026 – 2029 Forecasted)



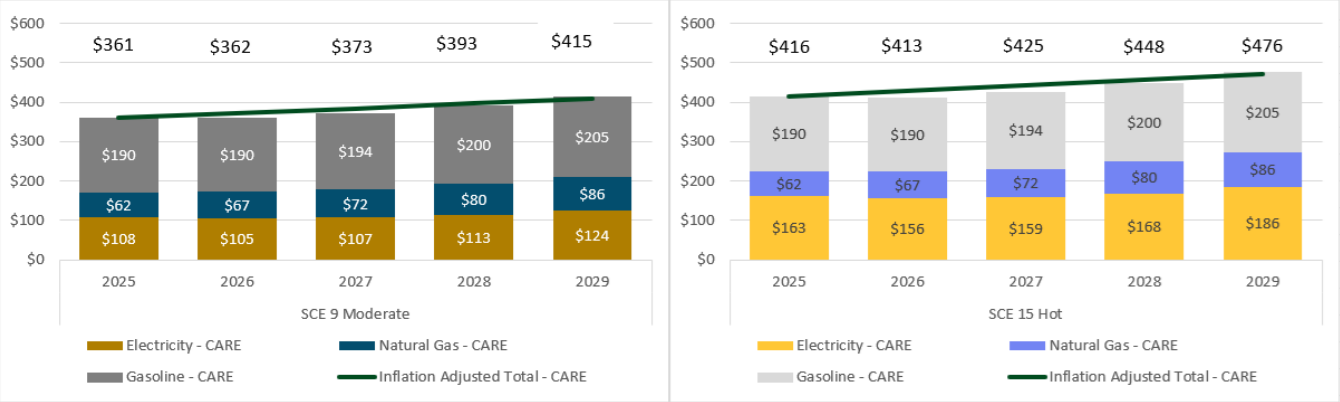
C-15: PG&E Base Case Total Energy Cost and Energy Share-of-Wallet, Typical CARE Customer, Moderate and Hot Climate Zones, (2025 Actual, 2026 – 2029 Forecasted)



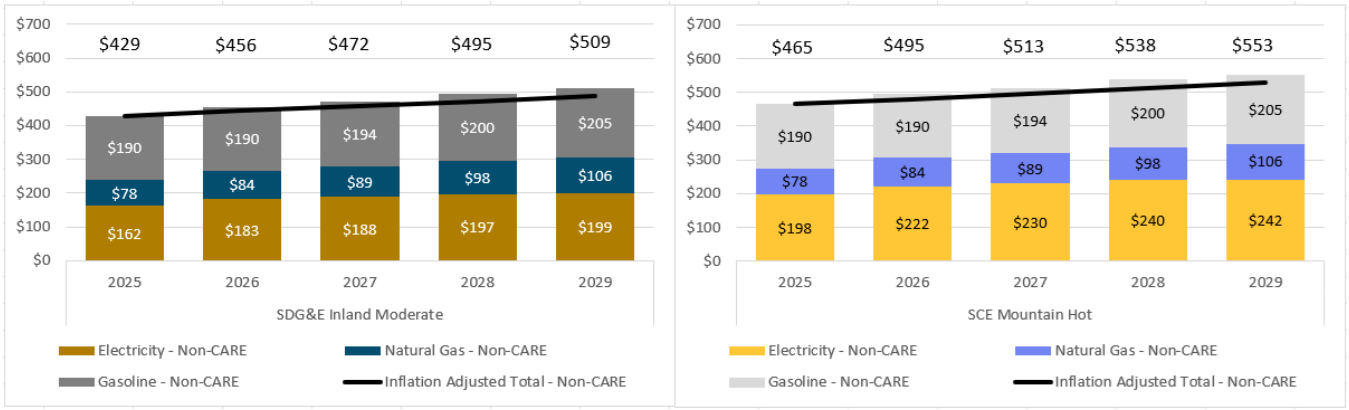
C-16: SCE/SoCalGas Base Case Total Energy Cost and Energy Share-of-Wallet, Typical Non-CARE Customer, Moderate and Hot Climate Zones, (2025 Actual, 2026 – 2029 Forecasted)



C-17: SCE/SoCalGas Base Case Total Energy Cost and Energy Share-of-Wallet, Typical CARE Customer, Moderate and Hot Climate Zones, (2025 Actual, 2026 – 2029 Forecasted)



C-18: SDG&E Base Case Total Energy Cost and Energy Share-of-Wallet, Typical Non-CARE Customer, Moderate and Hot Climate Zones, (2025 Actual, 2026 – 2029 Forecasted)



C-19: SDG&E Base Case Total Energy Cost and Energy Share-of-Wallet, Typical CARE Customer, Moderate and Hot Climate Zones, (2025 Actual, 2026 – 2029 Forecasted)

