2023 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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I. Executive Summary

The California Public Utilities Commission (CPUC) issues this 2023 Senate Bill (SB) 695 Report pursuant to Public Utilities Code Section 913.1, which requires the CPUC to publish recommendations that can be undertaken over the succeeding 12 months to limit California's Investor-Owned Utilities (IOU)[1] cost and rate increases consistent with the state's energy and environmental goals. The IOUs are also required by statute to study and report to the CPUC recommended measures to limit costs and rate increases.[2]

The CPUC's mission is to ensure that California IOU customers receive safe, reliable, affordable and clean utility service at just and reasonable rates.[3] In addition, since 2018 the CPUC has been directly addressing concerns about affordability and rising rates through our Affordability Rulemaking.[4] In 2021, our efforts intensified with a first Affordability En Banc hearing[5] to sharpen attention on affordability issues.[6] Then, in 2022, the CPUC held another Affordability En Banc hearing to deepen our review of stakeholder proposals and introduce new potential options to mitigate energy rate and bill increases.[7] At our third En Banc in 2023, the CPUC and stakeholders discussed recent high natural gas prices this past Winter, examined possible drivers and impacts on electric markets, and explored potential measures to mitigate the impact of natural gas and electric market volatility.[8]

California energy utility customers continue to face financial pressure from rate increases. Rate increases generally tracked inflation up to 2013,[9] but starting in 2021 rate increases began to outpace inflation for all three large electric IOUs[10] as shown in Figure 1.[11] This effect was particularly felt by residential customers, as these customers have higher rates than the system average.[12]

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1 "IOU" is used interchangeably with "utility" in this report.

2 *See* Public Utilities Code §913.1(b): In preparing the report required by subdivision (a), the [C]ommission shall require 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 costs and rate increases.

3 *See* CPUC website About the CPUC.

4 *See* Order Instituting Rulemaking (R.)18-07-006.

5 At an En Banc hearing, a quorum of Commissioners and their Advisors may be present but no decision will be made.

6 *See* February 24, 2021 En Banc hearing webcast.

7 *See* February 28, 2022 En Banc hearing webcast and March 1, 2022 En Banc hearing webcast.

8 *See* February 7, 2023 En Banc hearing webcast.

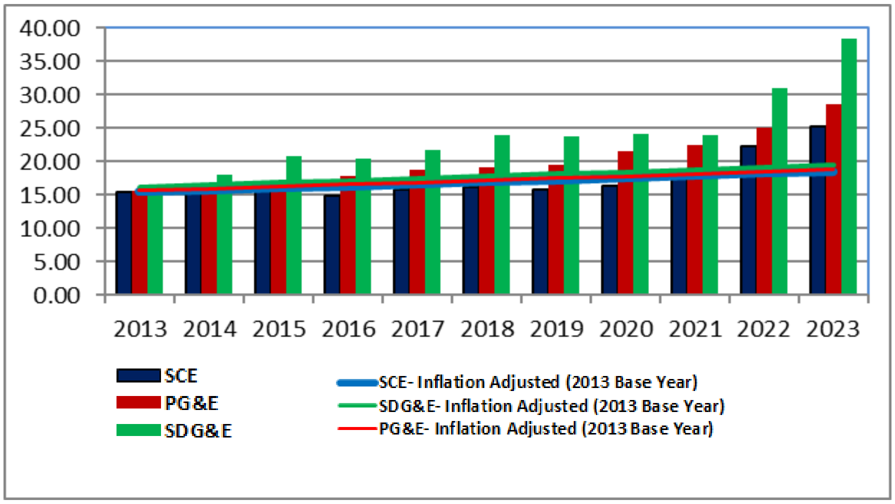
9 Prior to 2013, the electric total system average rate (i.e., all rate classes) of each of the IOUs roughly tracked inflation; *See* the 2022 Assembly Bill (AB) 67 Report.

10 Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE) and San Diego Gas and Electric Company (SDG&E).

11 Bundled system average rate level: Bundled IOU customers receive all services — generation, transmission, and distribution services — from the IOU; System-level includes all customer classes. Prior to 2021, only PG&E and SDG&E bundled system average rate growth exceeded inflation. Starting in 2021, SCE bundled system average rate growth also showed this effect.

12 See Figures 17-19 for a comparison of residential average rates to system average rates.

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



Since 2021, several key drivers have put upward pressure on electric rates, including sharp increases in wildfire risk costs—such as vegetation management efforts and wildfire liability insurance coverage—and higher fuel and energy costs, which have had a significant impact in 2023.

For natural gas rates, major drivers in 2023 include costs associated with maintaining the safety and reliability of the distribution mains, transmission pipelines, and storage facilities, as well as volatile commodity prices.

Over the next several years, wildfire risk mitigation costs are projected to continue their upward trend,[13] with a portion of the cost recovery corresponding to these projections going into rates, compounding ongoing wildfire risk mitigation cost recovery from previous costs incurred but not yet authorized for recovery.[14] Increased natural gas costs associated with safety-related programs to maintain or enhance the safety of gas pipelines and storage facilities are also expected.

[13] Wildfire risk mitigation costs include costs presented in each utility's Wildfire Mitigation Plan (WMP). *See* each IOU's most recent WMP at https://energysafety.ca.gov/what-we-do/electrical-infrastructure-safety/wildfire-mitigation-and-safety/wildfire-mitigation-plans/2023-wildfire-mitigation-plans/.

[14] Costs incurred in one year may be authorized for recovery in a later year. A utility's business decision about when to apply for cost recovery, along with the regulatory process, may add several years from the time costs are incurred until the time they are authorized for recovery. A third element going into rates over the next several years corresponds to ongoing capital-related costs (depreciation and return on rate base) from capital expenditures previously approved for recovery.

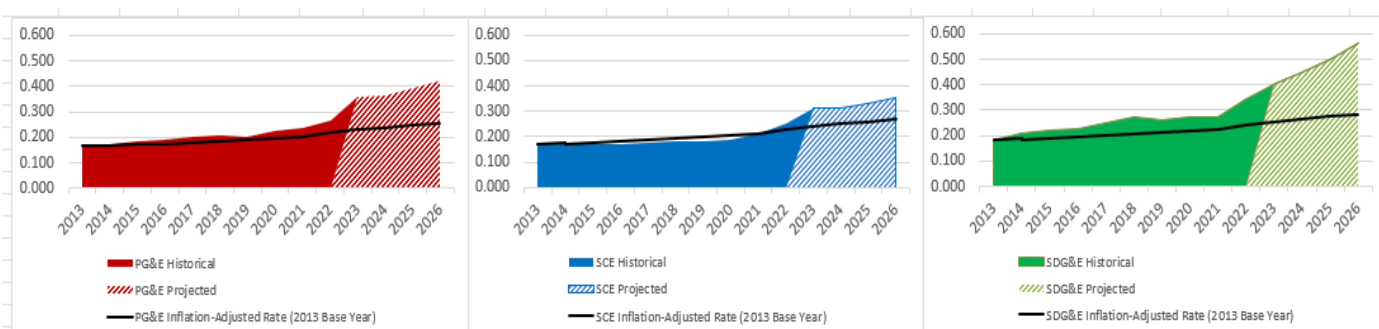
II. Introduction

California energy utility customers continue to face financial pressure from rate increases, and indicators show that energy costs will continue to outpace inflation in the near-term. The multiple drivers of these rate increases and costs are summarized below and described in greater detail in the body of the report. The CPUC is taking action in numerous ways to address these drivers of energy costs—consistent with our core mission of ensuring that today's rates are just and reasonable[15] while investing in electric and gas system safety and guiding California's investments in a clean energy future.

Rate Growth Continues To Outpace Inflation

Since 2013,[16] increases in bundled[17] residential average rates (RAR)[18] have exceeded the assumed rate of inflation,[19] with this trend expected to continue in the near term. Looking forward, the bundled RAR forecasts detailed in this report indicate the following average annual rate increases between the first quarter of 2023 and fourth quarter of 2026: PG&E 10.4 percent, SCE 6.0 percent, and SDG&E 10.4 percent. Figure 2 shows that by 2026, bundled RARs are forecast to be approximately 65 percent (PG&E), 30 percent (SCE), and 100 percent (SDG&E) higher than they would have been if rates for each IOU had grown at the rate of inflation since 2013.

Figure 2: PG&E (Red), SCE (Blue), and SDG&E (Green) Bundled Residential Average Rates, Nominal Historical and Projected with Inflation-Adjusted Comparison ($/kWh)



15 *See* Public Utilities Code § 451.
16 Prior to 2013, the electric total system average rate (i.e., all rate classes) of each of the IOUs roughly tracked inflation; *See* the 2022 Assembly Bill (AB) 67 Report. Rate increases calculated from January 1, 2013 to January 1, 2023.
17 Bundled customers take generation, distribution, and transmission services from an IOU. Unbundled customers receive distribution and transmission services from an IOU but receive generation services from competing providers.
18 Customer rates expressed in nominal $/kilowatt-hour (kWh).
19 Average annual rate is about 8 percent for PG&E, 7 percent for SCE, and 12 percent for SDG&E. Average annual inflation rate (2013 base year to 2023) is 3.4 percent, based on Consumer Price Index (CPI), California Region, All Items, All Urban Consumers, reported by the California Department of Finance (DOF), available here (CPI Forecast Data prepared in November 2022; 2022 & 2023 forecasted). Rate increases calculated from January 1, 2013 to January 1, 2023.

Drivers Behind Recent Rate and Cost Increases

Wildfire Risk Reduction Spending is a Primary Driver of Increases in Today's Electric Rates

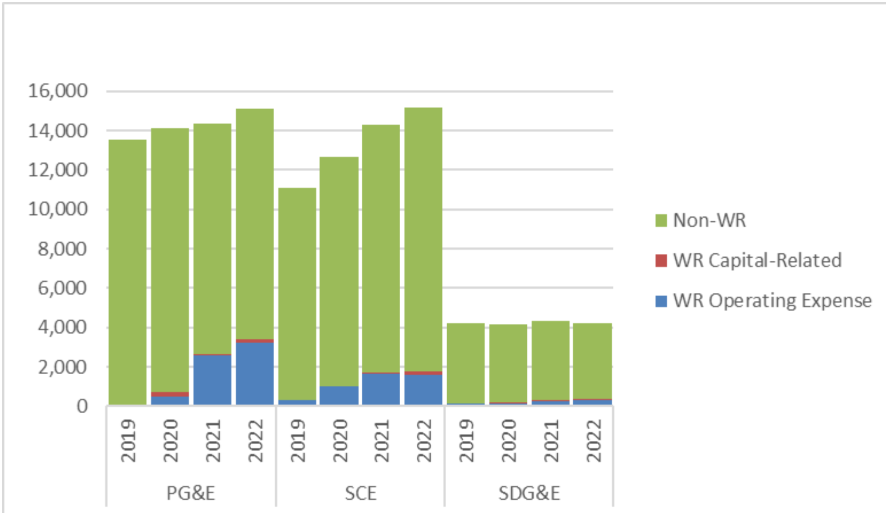
To fully understand increased wildfire risk spending, it is necessary to understand the difference between two categories of revenue requirement: operating expenses and capital expenditures.

Operating expense and capital-related costs authorized for recovery during ratesetting proceedings must be converted to revenue requirement to be recovered in rates. Operating expense is generally passed through to ratepayers without markup and is recovered from ratepayers on a dollar-for-dollar basis with no amortized cost recovery over time. Capital expenditures include depreciation expense recovered over a long period of time as the underlying asset depreciates, with an opportunity for the net capital investment to earn an authorized rate of return.[20]

In 2021, significant wildfire-related operating expenses, including vegetation management efforts and wildfire liability insurance coverage, began to appear in rates, with this trend intensifying in 2022, as shown in Figure 3.[21] While wildfire-related capital expenditures—such as installing covered conductor or undergrounding portions of a distribution system—are not yet a significant portion of the total revenue requirement in rates, the wildfire mitigation capital expenditure portions of PG&E and SCE's rate base[22] show a substantial increase over the 2021 – 2023 period.[23] As rate base grows, the capital-related revenue requirements corresponding to rate base also grow as the function of two effects—new capital expenditure spending and ongoing revenue requirement effects of previous capital expenditure spending—meaning that the wildfire-related capital revenue requirement may become a significant portion of the total revenue requirement in rates at a future point in time.

[20] *See* Chapter III for more details.
[21] Capital-related revenue requirement in Figure 3 is comprised of both capital expenditures and return on rate base. At year-end 2022, the wildfire-related portion of the total revenue requirement for each utility is: PG&E 23 percent, SCE 12 percent, and SDG&E 9 percent. *See* Chapter III for supporting details.
[22] Rate base is the net infrastructure investment at a given point in time.
[23] From IOU data responses to SB 695 Report data requests. *See* Chapter III for supporting details.

Figure 3: Wildfire-Related (WR) Revenue Requirement Relative to Total Revenue Requirement ($ millions)



Wildfire Risk Mitigation Spending Through 2025 is Projected to Increase Future Electric Rates

Wildfire risk mitigation spending is presented in each electric IOU's wildfire mitigation plan (WMP), a detailed plan which describes the level of wildfire risk in their service territory, how they intend to address those risks, and projected plan costs. The WMPs cover a three-year period with the upcoming 2023 - 2025 cycle[24] being the second in the series.[25] A comparison of the two cycles for the large electric IOUs shows significantly higher *planned* spending of about $26.2 billion for the 2023 – 2025 cycle than *actual* spend of about $20.7 billion in the previous 2020- 2022 cycle.[26] The order of magnitude of these costs shows the scale of the problem that California is facing: climate change is escalating, with stronger storms, hotter temperatures, and conditions that increase the risk of catastrophic wildfire.

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[24] The 2023 – 2025 WMPs were submitted in late March 2023 and have not yet been fully reviewed by Energy Safety. *See* each IOU's 2023 WMP at: https://energysafety.ca.gov/what-we-do/electrical-infrastructure-safety/wildfire-mitigation-and-safety/wildfire-mitigation-plans/2023-wildfire-mitigation-plans/.

[25] Stand-alone 2019 WMPs were also submitted; a review of the 2022 WMPs shows 2019 actual spend of about $6.2 billion.

[26] Of the actual spend, the revenue requirement corresponding to only about 60 percent of the spend has been collected in rates, with only a small portion of the capital-related portion of that revenue requirement reflected to date. The revenue requirement corresponding to the remaining 2020 – 2023 actual spend is either: (1) in the process of being approved i.e. requested for cost recovery in an open proceeding or (2) not yet filed for recovery. Cost recovery may be approved in amounts less than requested.

Today's Natural Gas Rates Reflect the Confluence of Recent High Commodity Prices and Continued Investment in Safety

The price spike of wholesale natural gas at the end of 2022 resulted in extraordinarily high gas rates and bills for many customers in early 2023. A confluence of events, including geopolitical developments that increased U.S. exports of liquified natural gas (LNG), below-average winter temperatures in the western United States, outages to interstate transmission pipelines that transport natural gas into California, limited storage options in Southern California, and an early-season draw-down of gas storage inventory contributed to increased customers' gas procurement rates in early 2023.

For natural gas, in 2023 utility revenue requirements in rates increased by 2.7 percent for PG&E, 0.5 percent for SDG&E, and 2.5 percent for Southern California Gas Company (SoCalGas) over 2022 utility revenue requirements.[27] The major cost drivers for California's gas utilities are associated with maintaining the safety and reliability of the distribution mains, transmission pipelines, and storage facilities, as well as volatile commodity prices. The overall trend of declining gas consumption in California due to the state's conservation and electrification efforts adds further pressure on natural gas transportation rates. In 2023, inflationary pressures are expected to place additional upward pressure on gas utilities' costs, driving up transportation rates.

Natural Gas Rates Are Expected to Increase Due to Increased Safety-Related Program Costs

Once PG&E's 2023 GRC is finalized, PG&E's revenue requirement is expected to rise due to increased costs associated with safety-related programs, including programs required by new regulations, to maintain or enhance the safety of gas pipelines and storage facilities. Similar cost pressures will impact SDG&E and SoCalGas in 2023. While the Sempra IOUs forecast a relative decrease in their respective procurement costs (which could offset their overall revenue requirement)[28], such procurement costs can be volatile and difficult to predict. For example, as seen at the end of 2022 and the beginning of 2023, the cost of procuring gas was extraordinarily high,[29] resulting in extremely high gas bills for IOU customers that period.

[27] PG&E's 2023 General Rate Case (GRC) Application was not issued in time for the January 1 rate change, therefore, PG&E's 2022 authorized base revenues are reflected in this report.
[28] In 2023, SoCalGas projects a 28% decrease in commodity costs ($1.21 billion) relative to its 2022 commodity costs of $1.67 billion; SDG&E projects a 27% decrease in commodity costs ($198 million) relative to its 2022 commodity costs of $271 million. Cold weather, geopolitical conflict, and pipeline capacity constraints drove their commodity cost higher in 2022.
[29] For example, the CEC determined that gas prices for delivery in December 22, 2022 were seven times higher than for the same day the year prior.

The Fixed Cost Allocation Challenge: The Mismatch Between Electric Fixed Costs and Today's Volumetric Rate Design

The above cost drivers for electricity are compounded by a structural mismatch affecting electric rates. Today, each utility's costs, including funds for generation, transmission and distribution, are recovered from customers almost exclusively via a volumetric rate – pay for what you use.[30] Yet that rate design contrasts with how IOU costs are actually incurred: only a portion of an IOU's costs (principally generation and some distribution costs) directly vary based on how much energy a customer consumes. Many infrastructure and operational costs, referred to as "fixed costs," do not. Collecting these fixed costs through a uniform charge, not tied to consumption, would align better with the cost of service and reduce the amount of a customer bill collected through volumetric rates. This would help to control high bills associated with event-driven higher usage—such as heat waves or cold temperatures—and enhance the attractiveness of the electrification efforts needed to achieve the state's greenhouse gas (GHG) reduction goals. An income-graduated basis for the fixed charge would require higher-income households to pay a larger proportion of overall fixed costs to more equitably share the burden of funding electric system infrastructure. California adopted a first-in-the-nation law requiring the establishment of an income-graduated fixed charge in 2022, and the CPUC is leading a proceeding to reform rates to implement this important equity tool.[31]

CPUC Actions Currently Underway to Mitigate Cost and Rate Increases as California Continues to Invest in a Clean Energy Future

The CPUC's core mission is to ensure that rates and costs are just and reasonable, and necessary for the provision of reliable, affordable and clean service. This means using tools to accomplish several goals: mitigate cost and rate increases in every way possible; constantly seek ways to allocate energy costs more equitably for Californians; and plan and guide investments to make progress toward electrification and climate goals. With those three goals in mind, the CPUC is implementing the following cost management strategies:

1. ***Implement the first-in-the-nation income-graduated fixed charge.*** Pursuant to the directives set forth in Assembly Bill (AB) 205 and the Demand Flexibility Rulemaking,[32] the CPUC is considering proposals for the implementation of income-graduated fixed

[30] SCE is the only large electric IOU with a fixed charge, currently about one dollar per month.
[31] For more information on this proceeding, *see* the next section in this chapter.
[32] *See* R.22-07-005.

charges,[33] the first of their kind in the nation, for all residential customers who use the grid. Income-graduated fixed charges are not adding new costs to customer rates and bills. By design, fixed charges recover certain authorized utility costs that are currently collected through volumetric components of electricity bills.[34] The income-graduated aspect of the fixed charges requires higher-income households to pay a larger proportion of overall fixed costs, providing relief for lower-income households. Lowering volumetric rates mitigates rate impact and will encourage decarbonization by making transportation and building electrification more affordable. Matching income levels with the level of monthly fixed charge each customer pays should also recover electric system infrastructure costs more equitably.

2. ***Continue supporting state efforts to decarbonize the grid and scale deployment of clean energy generation and storage by using the General Fund.*** For example, California's 2023 – 2024 Governor's Budget[35] proposes, among other things, approximately $630 million from the General Fund for solar and storage incentives entirely for low-income utility customers. This type of support directly mitigates ratepayer costs and builds equity by providing an opportunity to allocate state funding to low-income customers for storage deployment technology—at a time when storage's role in both maintaining grid reliability and acting as price hedge[36] is becoming increasingly important. General Fund support for the costs in this example, and potentially in other cases such as for building and transportation electrification, will help to promote statewide decarbonization policies by reducing electricity costs overall.

3. ***Actively pursue other sources of funding for the grid investments that California needs to make to achieve our clean energy goals.*** The CPUC is working with several agencies across the administration to position California to receive federal grant and loan opportunities available through the Infrastructure Investment and Jobs Act (IIJA), the Inflation Reduction Act (IRA), and the Creating Helpful Incentives to Produce Semiconductors and Science Act (CHIPS). Federal funding available under these Acts may displace the need for ratepayer funding and support investment in California while mitigating costs to ratepayers. In April 2023, through Resolution E-5254, CPUC also established a process to track project requests by the utilities that may be funded through federal grants.

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[33] Fixed charges should recover wildfire-related costs, electrification grid and other costs, and beneficial public costs and other non-bypassable charges (NBCs), which are costs of public purpose programs (PPP) and certain other programs or costs that are paid by all customers who use the utility delivery system.

[34] Infrastructure investment and maintenance costs, including those related to wildfire, are under consideration in this proceeding as fixed costs to be collected as fixed charges.

[35] *See* California's 2023 – 2024 Governor's Budget.

[36] Storage at the utility level may act as a price hedge as part of a utility's gas-fired generation operations and at the customer level as a type of price hedge for maximizing the benefits of a TOU pricing structure e.g. self-consumption or export during TOU periods with higher rates.

4. ***Investigate the extraordinarily high gas prices in Winter 2022-2023.*** Building on the information gathered at an En Banc[37] with market experts to examine the causes and impacts of the Winter 2022 – 2023 high natural gas prices,[38] the CPUC launched a proceeding[39] in March 2023 to continue our fact-gathering effort on the causes of the extraordinarily high gas prices this past winter; to examine impacts on gas and electric bills; to investigate whether the utilities' communications were sufficient; and to explore potential solutions to avoid similar events in the future and minimize their impacts if they do occur. The CPUC also continues to pursue policies to limit gas utilities' costs and rate increases.[40] Parallel to redesigning electric rates to implement more equitable cost allocation, the CPUC will also address the issue of fixed charges in natural gas rate design, to lower volumetric transportation rates and dampen bill volatility.[41]

5. ***Monitor and plan long-term gas cost and infrastructure as the state continues to transition to electrification.*** In the Long-Term Gas Planning Order Instituting Rulemaking (OIR), the CPUC will examine ways to streamline the implementation of gas safety rules to save costs. For instance, California could revise Pipeline Safety Enhancement Plans (PSEP) rules to allow for the maximum allowable operating pressure (MAOP) reconfirmation strategies approved by the federal Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA), rather than requiring that all transmission pipelines be pressure tested or replaced.

6. ***Continue using affordability analyses to drive equity initiatives.*** The CPUC's cross-industry affordability metrics[42] are the first such analysis in the nation. In applications requesting revenue increases exceeding one percent of system-level revenues currently authorized, utilities are required to show the corresponding bill impacts and affordability impacts for the residential customer class. These impacts are also to be shown through additional lenses for the most disadvantaged residential customers: those at the lower end (20th percentile) of the income distribution, those earning minimum wage, and those in areas facing severe economic challenges.

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[37] *See* February 7, 2023 En Banc hearing webcast.

[38] Other actions taken in response to the Winter 2022 – 2023 high natural gas prices included directing utilities to enhance customer communications and accelerating the timeframe in which residential energy customers would receive a Climate Credit on their bills

[39] *See* Order Instituting Investigation (I.)23-03-008.

[40] For instance, in the context of the Long-Term Gas Planning Order Instituting Rulemaking (R.)20-01-007, the CPUC recently approved General Order 177, which requires the consideration of non-pipeline alternatives for large transmission projects. The CPUC also issued a Staff Proposal outlining a process for pruning the gas distribution system to avoid the risk of stranded assets and help decision-makers employ targeted gas distribution pipeline decommissioning and electrification.

[41] This will be considered in a later track of R.20-01-007.

[42] *See* the CPUC Affordability Proceeding – Phase 2 Implementation of Affordability Metrics webpage.

Organization of the 2023 SB 695 Report

The remainder of this report is organized as follows:

- **Chapter III**: A foundational review of *historical* trends in electric costs, rates, and bills with a focus on longer-term, capital-related costs and impacts on bills from wildfire safety, clean energy programs, and statutory mandates that have historically resulted in additional ratepayer costs.

- **Chapter IV:** An evaluation of electric cost and rate *projections*. In addition, this chapter highlights affordability concerns in low to moderate income households.

- **Chapter V**: Natural gas cost and rate trends.

- **Appendices:** Information provided by the IOUs to fulfill the requirements of Public Utilities Code Section 913.1(b) and reference material.

A digital copy of this report can be found at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-rates.

III. ELECTRIC IOU HISTORICAL COST AND RATE TRENDS

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 profit, while ensuring that rates are just and reasonable. The cost-of-service regulatory model aims to provide universal access to safe and reliable electricity while ensuring monopoly utility service providers charge a fair price.

Historical Trends in Electric Revenue Requirement and Rates

Utilities file detailed descriptions of the costs of providing service (also referred to as "revenue requirements") and request authorization to recover these costs in various rate-making proceedings. Most utility costs, other than the cost of procuring fuel and purchased power,[43] are generally addressed in General Rate Case (GRC) proceedings.[44] GRCs are forward-looking, as IOUs forecast and estimate their anticipated costs to operate their respective utility. In GRC proceedings, the CPUC sets a pre-specified revenue requirement for the first year in the cycle, or "test year," with formulaic adjustments for the subsequent "attrition years" until the next GRC cycle commences.

In addition to forecasting costs for recovery, GRCs may include requests for recovery of costs that have already been incurred i.e. recorded costs in balancing accounts and memorandum accounts. A balancing account is established to record certain authorized costs for recovery through rates and to ensure the revenue collected matches the authorized amounts. Balancing account revenue balances are to be returned to ratepayers if the account is over-collected, and in some circumstances additional revenue can be recovered from ratepayers if the account is under-collected. Memorandum accounts are similar to balancing accounts except they record costs not yet authorized and are subject to reasonableness reviews by the CPUC and may or may not be recoverable through rates.[45]

Utilities may periodically also be directed by the CPUC to file applications pursuant to legislative mandates. For example, applications have been filed in the last several years for program investments and market structures to support wider deployment of zero-carbon vehicles and grid modernization, and as a result, substantial costs have been recently authorized in proceedings for transportation electrification and energy storage.

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[43] Most energy procurement costs are addressed in annual Energy Resource Recovery Account (ERRA) Forecast proceedings. ERRA costs are pass-through expenses; the utility receives no mark up or profit on these costs.

[44] For more detailed descriptions of how GRC proceedings and Energy Resource Recovery Account (ERRA) proceedings authorize utility revenue requirements *see* the [2022 AB 67 Report].

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

Revenue Requirement by Rate Component

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

The **generation** rate component collects the revenue requirement corresponding to generation portfolio costs. This rate component recovers the cost of Utility Owned Generation (UOG), consisting of fuel expense and operating and capital costs associated with generation plants such as nuclear, gas, and hydroelectric. IOUs also recover "purchased power costs" which represent the costs of electricity from third-party generators. The incremental cost impact of renewable contracts to meet the Renewables Portfolio Standard (RPS) and greenhouse gas (GHG) costs[46] is also reflected in generation rates.

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

The **transmission** rate component collects the revenue requirement associated with the interstate transmission assets owned by the utilities. Transmission rates are primarily set by the Federal Energy Regulatory Commission (FERC) in Transmission Owner (TO) rate cases, in which the CPUC represents California ratepayers as an advocate for just and reasonable transmission rates. The overall transmission rate component is comprised of four sub-components: 1) Base Transmission Revenue Requirement, which is set in TO rate cases and recovers the costs associated with transmission assets under ISO operational control and subject to FERC's jurisdiction; 2) transmission revenues that flow to retail customers from wholesale customers' use of the transmission system; 3) Reliability Services costs related to contracts signed by the California Independent System Operator (CAISO) with certain generators needed to maintain system reliability; and 4) the Transmission Access Charge Balancing Account Adjustment, which accounts for the over- or under-collection of what the IOU receives for the cost of operating its high voltage

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

assets compared to what it has to pay for its use of the CAISO-controlled regional high voltage grid.

Other rate components include:

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

The **PPP** rate component collects program funding authorized by the CPUC for Energy Efficiency, Low-Income programs, and other public policy programs. **NSG** charges recover the costs of "new generation" assets the IOUs procure to maintain system reliability. **CTC** recover above-market costs associated with power purchase contract obligations that resulted from electric industry restructuring pursuant to Public Utilities Code Section 367(a). **ND** costs flow into a trust maintained for assurance that complete decommissioning activities for nuclear facilities may be undertaken and are recovered separately in the ND rate component. **WFC** recover costs to fund the wildfire fund created by Assembly Bill (AB) 1054 (Holden, 2019).[47] Wildfire Bond Securitization **FRC** are charges for certain wildfire capital costs recovery bonds that AB 1054 permits to be securitized through a CPUC financing order rather than being financed through the more traditional unsecured bond offerings.[48] The **TRAC** reflects the cost shift that resulted from capped residential tiered rates previously legislated under AB 1X and SB 695.[49] The **ECRA** rate component is used to

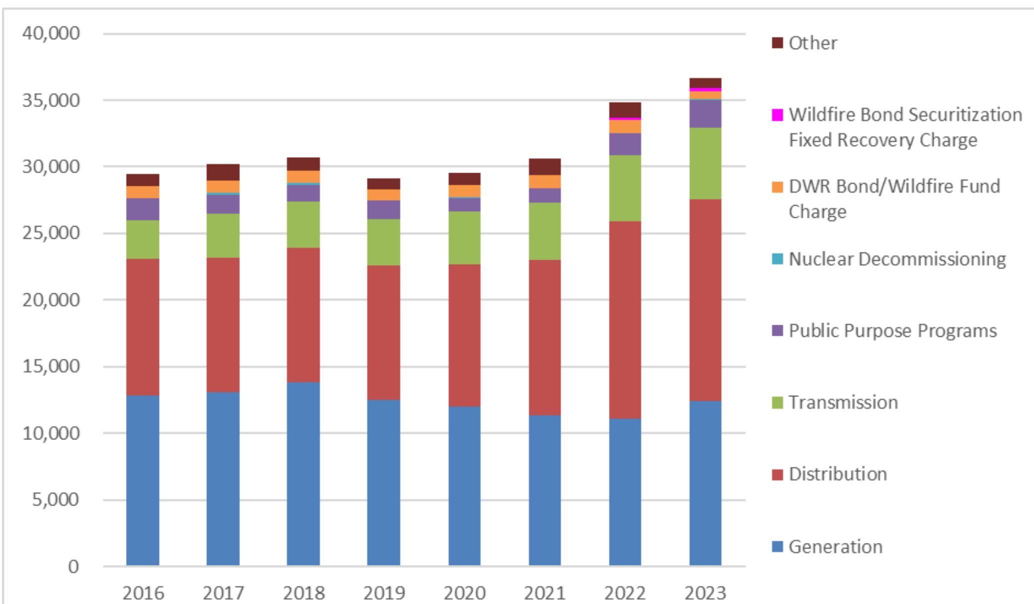
[47] Starting October 2020. Prior to October 2020, the non-bypassable charge was known as the Department of Water Resources (DWR) Bond Charge for the repayment of bonds issued in 2003 to recover the costs incurred by the State of California to purchase power during the energy crisis.
[48] PG&E and SCE currently have AB 1054 securitizations that are recovered through a non-bypassable fixed recovery charge.
[49] Applies to SDG&E only.

return amounts to customers resulting from settlement agreements with sellers of energy to resolve energy claims related to the Western Energy Crisis of 2000-2001 ("FERC energy crisis refund").[50]

Revenue Requirement by Rate Component Trends

Figure 4 presents combined authorized revenue requirement rate component trends for the electric IOUs at system-level.[51] Data is anchored to January 1 each year to maintain consistent year-over-year comparisons,[52] and is combined to provide a high-level comparison of the revenue requirement rate components and overall revenue requirement over time. More detailed analysis of select revenue requirements for each IOU is provided in the subsequent sections of this chapter.[53]

Figure 4: PG&E, SCE, and SDG&E Revenue Requirement by Rate Component Category (January 1, $ millions)



[50] Applies to PG&E only.

[51] System-level includes all customer classes and all bundled and unbundled customers i.e. it is the total revenue requirement that the IOU collects. Generation includes Power Charge Indifference Adjustment (PCIA), a rate component intended to equalize cost sharing between departing load and bundled load. Distribution includes the netting effect of the semi-annual Greenhouse Gas Revenue Return credited to eligible customers through this rate component. Other includes NSG, CTC, TRAC and ECRA rate components. For 2023, DWR Bond/Wildfire Fund Charge reflects a DWR refund for over-collected DWR bond charges. Revenue requirement does not capture programs that result in a cross-subsidy between various customers groups such as the California Alternate Rates for Energy (CARE) surcharge between Non-CARE and CARE customers, which can add a

Revenue Requirement by Operating Expense and Capital-Related Cost Categories

Operating expense and **capital-related costs** authorized for recovery during ratesetting proceedings must be converted to revenue requirement to be recovered from ratepayers as part of rates implementation.

Operating expense is generally passed through to ratepayers without markup and is recovered from ratepayers on a dollar-for-dollar basis with no amortized cost recovery over time, meaning the utility earns no profit on operating expense which it recovers based on the year the expense was incurred. Operating expense includes operations and maintenance (O&M) expenses and administrative and general (A&G) expenses. O&M expenses include all labor and non-labor costs for a utility's operation and maintenance of its generation, distribution, and transmission infrastructure. A&G expenses include costs such as liability insurance and non-infrastructure personnel costs. O&M expenses and A&G expenses comprise the utility's **operating expense revenue requirement.**

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

Capital-related costs include: **(1) depreciation expense**[54] recovered over a long period of time as the underlying asset depreciates and **(2) an authorized profit** on the net capital investment,[55] known as return on rate base.[56] Return on rate base along with capital investment depreciation expense comprise the utility's **capital-related revenue requirement.**

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

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, with the capital-related revenue requirement included in rates for many years. Furthermore, increases in rate base over time result in increasing returns on rate base and depreciation expense revenue

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significant amount to the PPP rate paid by Non-CARE customers. All dollars are nominal i.e., not adjusted for inflation unless otherwise indicated.

[52] Data time series starts in 2016 and is from IOU data responses to SB 695 Report data requests. The AB 67 reports here (Reports to the Legislature, linked by year) provide detailed cost recovery data for each IOU using a floating effective date generally corresponding to each IOU's last rate implementation of the report year. *See* the AB 67 reports for data prior to 2016 and for more detail about factors driving electric revenue requirements for each IOU.

[53] A comprehensive review of utility revenue requirement was not performed, but rather, specific cost categories were selected for further examination. For example, wildfire mitigation and wildfire liability are among the near-term costs that may place upward pressure on rates and bills.

[54] Net of related tax effect.

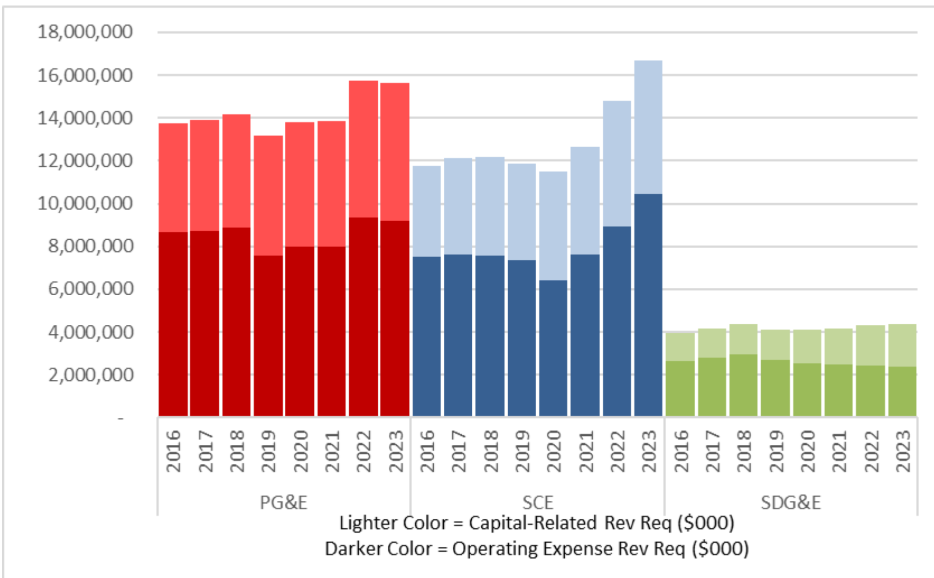
[55] Net of accumulated depreciation.

[56] Return on rate base is calculated by multiplying the IOU's authorized rate of return by rate base. This produces a type of financing cost.

requirements, as return on rate base and depreciation are now being calculated relative to an increasing base amount.

Operating expense revenue requirement can have a larger immediate impact on rates in the short run, yet a smaller impact relative to capital-related revenue requirement in the long run. Capital-related revenue requirement has a larger cumulative impact on rates relative to operating expenses in the long run on a dollar-for-dollar basis as it is amortized in rate base over a longer time horizon during which the IOUs earn a rate of return on rate base. Figure 5 shows for each IOU the relative share of the total operating and capital-related portion of the total revenue requirement.[57] The ratio of operating expense revenue requirement to capital-related revenue requirement has declined since 2016, from about 65%/35% of the total revenue requirement, respectively, in 2016 to about 60%/40% for PG&E and SCE and 55%/45% for SDG&E in 2023.

Figure 5: PG&E, SCE, and SDG&E Operating Expense and Capital-Related Revenue Requirements (January 1, $ millions)



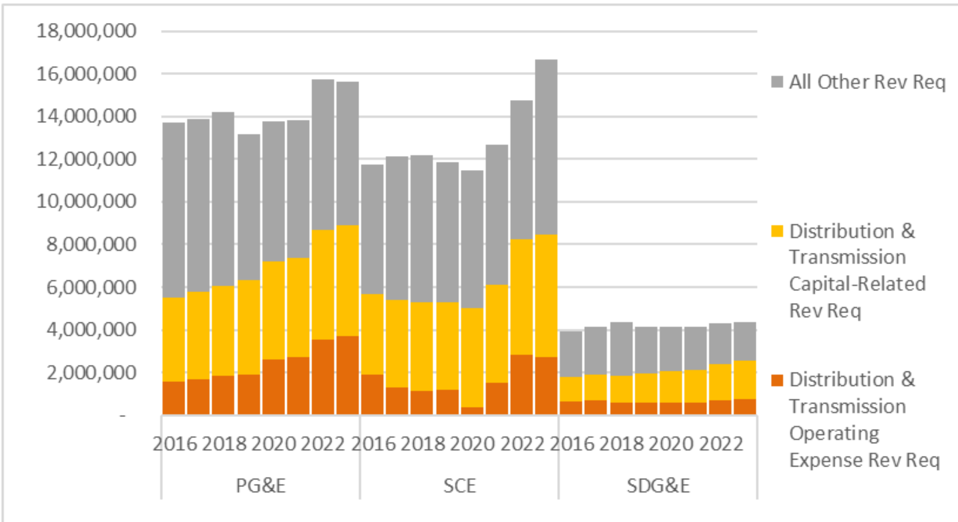
Distribution and transmission operations and infrastructure investments are major cost drivers that continue to comprise a significant portion of IOU costs and rates. Figure 6 shows the composition of these cost drivers relative to total revenue requirement.[58] PG&E and SDG&E show an increasing total distribution and transmission revenue requirement proportion relative to all other revenue requirements over time, from about 40% of the total revenue requirement in 2016 to

[57] For this figure and the rest of the revenue requirement figures in this section: (1) data time series starts in 2016 and is from IOU data responses to SB 695 Report data requests. For data prior to year 2016, *see* the AB 67 reports here (Reports to the Legislature, linked by year); (2) revenue requirements that are not capital-related are classified as operating expenses; (3) data for years prior to 2022 may be updated; and (4) includes Franchise Fees & Uncollectibles (FF&U) unless otherwise indicated.

[58] While a revenue requirement increase greater than inflation doesn't necessarily translate directly into a rate increase greater than inflation, revenue requirement provides a proxy for how inflationary effects of distribution and transmission operating expense may flow down to affect affordability of customer rates.

approximately 60% in 2023. SCE distribution and transmission revenue requirements remain largely constant over this time period at approximately 50% of total revenue requirement.

Figure 6: PG&E, SCE, and SDG&E Distribution and Transmission Operating Expense and Capital-Related Revenue Requirements (January 1, $ millions)



Operating Expense Revenue Requirement

PG&E distribution and transmission operating expense revenue requirements and SCE distribution operating expense revenue requirements have been increasing at an average annual percent change greater than the assumed inflation rate of 4.1 percent.[59] The primary driver of these costs is wildfire mitigation work, including enhanced inspections and vegetation management efforts.[60] Tables 1-2 show distribution and transmission operating expense revenue requirements for each of the IOUs in 2016 and 2023 along with the corresponding average annual percent change.[61] Since 2016, distribution operating expense revenue requirement has been increasing on average approximately 11 percent per year for PG&E, 7 percent per year for SCE, and 3 percent per year for SDG&E. Over this same timeframe, transmission operating expense revenue requirement has been increasing on average approximately 126 percent per year for PG&E, 4 percent per year for SCE, and 2 percent per year for SDG&E.

[59] Average annual inflation rate (2016 base year to 2023) is 4.1 percent, based on Consumer Price Index (CPI), California Region, All Items, All Urban Consumers, reported by the California Department of Finance (DOF), available here (CPI Forecast Data prepared in November 2022; 2022 & 2023 forecasted). While this inflation measure may not necessarily be representative of expected utility cost escalation, it provides a proxy for how inflationary effects of distribution and transmission operating expense revenue requirements may flow down to affect affordability of customer rates.

[60] A one-off driver of a substantial increase in PG&E transmission revenue requirement occurred in 2017 and is explained in further detail below.

[61] For this table and the rest of the revenue requirement tables in this section, data time series starts in 2016 and is from IOU data responses to SB 695 Report data requests. For data prior to year 2016, *see* the AB 67 reports here (Reports to the Legislature, linked by year).

For PG&E, substantial increases in transmission operating expense revenue requirement occurred over the periods 2016 – 2017, 2019 – 2020, and 2022 - 2023.[62] The increase from 2016 to 2017 was driven by changes in balancing accounts balances, with the Transmission Access Charge Balancing Account Adjustment (TACBAA)[63] driving the bulk of the increase. The main driver of the TACBAA increase in 2017 was due to the CAISO system-wide transmission access charge (TAC) rate being much larger than the CAISO's forecast of the 2016 TAC, creating a large under-collected balance in the TACBAA in 2016 that was recovered the following year.[64] The driver of the increase from 2019 to 2020 and from 2022 to 2023 were expenses recovered in PG&E's transmission owner rate cases at FERC.[65]

Table 1: Distribution Operating Expense Revenue Requirement, January 1, 2016 and January 1, 2023 ($ billions, with Average Annual Percent Change)

Utility	2016	2023	AAPC
PG&E	$ 1.412	$ 2.475	10.7%
SCE	$ 1.583	$ 2.358	7.0%
SDG&E	$ 0.482	$ 0.566	2.9%

Table 2: Transmission Operating Expense Revenue Requirement, January 1, 2016 and January 1, 2023 ($ billions, with Average Annual Percent Change)

Utility	2016	2023	AAPC
PG&E	$ 0.127	$ 1.244	126.2%
SCE	$ 0.291	$ 0.368	3.8%
SDG&E	$ 0.167	$ 0.183	1.6%

Capital-Related Revenue Requirement

[62] The increase from 2016 to 2017 was four-fold, from about $127 million to $518 million; the increase from 2019 to 2020 was from about $586 million to $917 million; the increase from 2022 to 2023 was from about $1.0 billion to $1.2 billion.
[63] The TACBAA is a FERC-jurisdictional mechanism designed to provide recovery of differences between utility-specific transmission rates and CAISO grid-wide transmission rates on the high voltage grid (*i.e.,* 200kV or higher).
[64] The TAC reflects TO costs related to assets on the high voltage (200+kV) grid. Large new high voltage transmission projects going online drive up the total revenue requirement being collected regionally (i.e., through the TAC). The TAC rate (i.e., the cost per MWh to use the high voltage grid) is the same for all load serving entities (LSE), taking into account the total regionally allocated revenue requirement for all high voltage transmission owners. In 2016 PG&E was collecting a set amount to pay for its portion of the grid, but the cost to use the high voltage grid as an LSE spiked because of others' high voltage assets coming online. The increase in total grid-wide revenue requirement resulted in an under collection and the need for a substantial balancing account adjustment the following year.
[65] Between 2019 and 2020, PG&E's FERC rates included increases related to wildfire work and COVID-related costs for grid operations, as well as an increase in expenses for general liability insurance, Injuries and Damages, salaries, and property insurance. Between 2022 and 2023, PG&Es FERC rates included increases related to wildfire work and other upgrades for grid operations as well as an increase in expenses for general liability insurance, Injuries and Damages, salaries, property insurance, and other administrative and general (A&G) items.

Capital-related revenue requirements depend primarily on **rate base**, which is essentially the book value of the utility's assets after taking accumulated depreciation into account.[66] When net capital additions[67] exceed accumulated depreciation, which has generally been the case for PG&E, SCE, and SDG&E, rate base increases. Rate base is multiplied by each utility's rate of return on rate base[68] to produce **the return on rate base revenue requirement**.

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

There is thus a direct correlation between rate base growth and return on rate base revenue requirement growth. Tables 3-4 show distribution and transmission capital-related revenue requirements, rate base,[69] and return on rate base revenue requirements for each of the IOUs in 2016 and 2023 along with the corresponding average annual percent change.

Table 3: Distribution Capital-Related Revenue Requirement, Rate Base, and Return on Rate Base Revenue Requirement
January 1, 2016 and January 1, 2023 ($ billions, with Average Annual Percent Change)

	Capital-Related Revenue Requirement			Rate Base			Return on Rate Base Revenue Requirement		
Utility	2016	2023	AAPC	2016	2023	AAPC	2016	2023	AAPC
PG&E	$ 2.901	$ 3.339	2.2%	$ 13.494	$ 19.049	5.9%	$ 1.098	$ 1.361	3.4%
SCE	$ 2.929	$ 4.677	8.5%	$ 14.913	$ 27.895	12.4%	$ 1.294	$ 2.219	10.2%
SDG&E	$ 0.777	$ 1.118	7.3%	$ 3.637	$ 5.931	9.0%	$ 0.283	$ 0.426	7.2%

Table 4: Transmission Capital-Related Revenue Requirement, Rate Base, and Return on Rate Base Revenue Requirement
January 1, 2016 and January 1, 2023 ($ billions, with Average Annual Percent Change)

	Capital-Related Revenue Requirement			Rate Base			Return on Rate Base Revenue Requirement		
Utility	2016	2023	AAPC	2016	2023	AAPC	2016	2023	AAPC
PG&E	$ 1.057	$ 1.862	10.9%	$ 5.371	$ 11.925	17.4%	$ 0.431	$ 0.881	14.9%
SCE	$ 0.886	$ 1.045	2.6%	$ 5.171	$ 27.895	5.9%	$ 0.378	$ 0.517	5.3%
SDG&E	$ 0.365	$ 0.677	14.3%	$ 2.896	$ 5.931	9.8%	$ 0.221	$ 0.372	9.8%

Rate Base

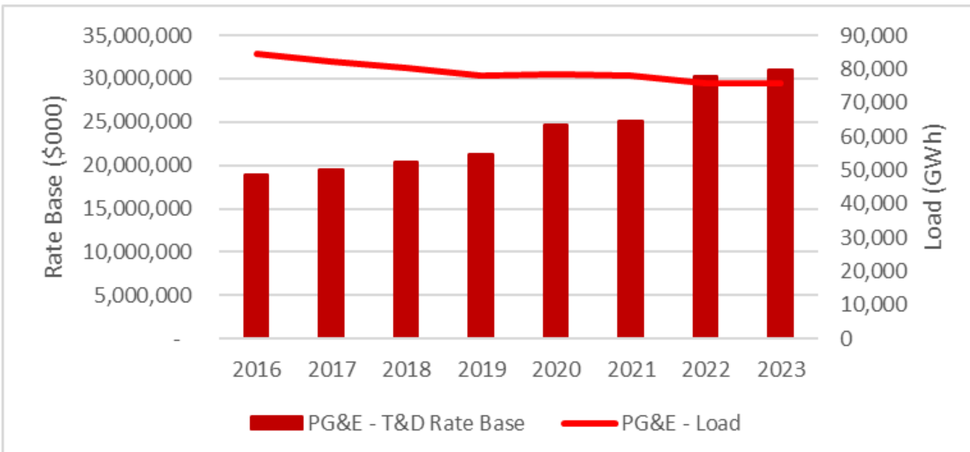
Increases in rate base have a direct relationship with increases in the capital-related revenue requirement. Tables 3-4, above, show that since 2016, distribution and transmission rate base has been increasing on average approximately 6 percent and 17 percent for PG&E, respectively, 12

[66] Depreciation spreads the cost to ratepayers of the capital investment over the assets' useful life. Accumulated depreciation is the cumulative depreciation of an asset up to a single point in its life.
[67] Net capital additions are net of retired or otherwise removed capital balances.
[68] Each IOU's rate of return on rate base is authorized in a cost of capital proceeding.
[69] Data time series starts in 2016 and is from IOU data responses to SB 695 Report data requests. Rate base shown for net plant/capital additions only, i.e. "other" non-plant/capital additions rate base is not included.

percent and 6 percent for SCE, respectively, and 9 percent and 10 percent for SDG&E, respectively. For all three IOUs, combined distribution and transmission rate base has been growing at about 10% per year on average since 2016.

Figures 7-9 show distribution and transmission rate base and retail load delivered by each IOU over the 2016 – 2023 period.[70] Growth in distribution and transmission rate base shows a mismatch with load delivered, with rate base continuing to increase since 2016 while total energy delivered has been declining overall since 2016.

Figure 7: PG&E Distribution and Transmission Rate Base (January 1, $000) and Retail Energy Delivered (GWh)



[70] Retail load delivered from California Energy Commission (CEC) 2022 Integrated Energy Policy Report (IEPR), California Energy Demand 2022-2035 Planning Forecast, Load Serving Entity (LSE) tables, 2016 – 2021 actual data, 2022 – 2023 forecasted data. Retail load delivered may be affected by weather among other factors.

Figure 8: SCE Distribution and Transmission Rate Base (January 1, $000) and Retail Energy Delivered (GWh)

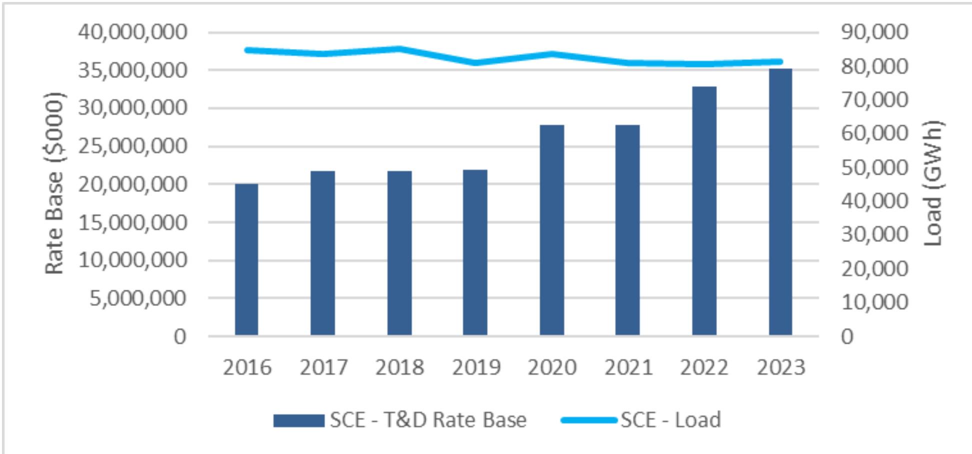
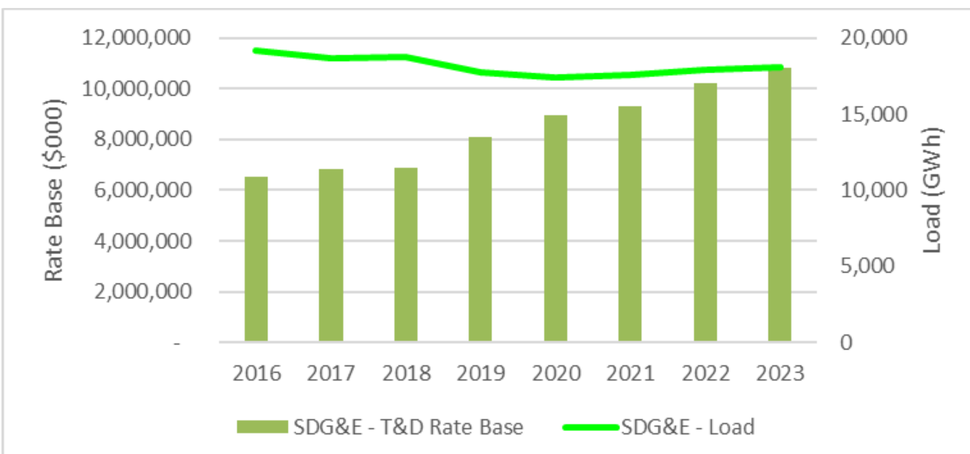


Figure 9: SDG&E Distribution and Transmission Rate Base (January 1, $000) and Retail Energy Delivered (GWh)



The general trends in Figures 7-9, above, are expected to continue as wildfire mitigation capital costs continue to increase rate base.[71] PG&E parent company PG&E Corporation's fourth quarter 2022 earnings presentation included "undergrounding" and "additional wildfire mitigation (including remote grid integration)" as potential rate base growth opportunities.[72] SCE parent company Edison

[71] Other non-wildfire related capital costs, such as costs to upgrade infrastructure for transportation electrification, are not expected to significantly impact rates in the near term. *See* PG&E 2023 GRC (A.21-06-021) testimony in CPUC Regulatory Case Documents for one such example.

[72] Transportation electrification is also included in this list. *See* fourth quarter 2022 earnings presentation: https://s1.q4cdn.com/880135780/files/doc_financials/2022/q4/Q4'22-Earnings-Presentation.pdf.

International's fourth quarter 2022 earnings presentation states that "strong rate base growth [is] driven by wildfire mitigation and important grid work to support California's leading role in pivoting to a carbon-free economy." Potential capital expenditure opportunities for 2024 and beyond include "deployment of incremental miles of covered conductor" and "infrastructure replacement and load growth."[73] SDG&E's parent company Sempra fourth quarter 2022 earnings presentation does not mention rate base or wildfire mitigation.[74]

Despite some ratepayer relief afforded by AB 1054's equity rate base exclusion provisions, which reduced wildfire mitigation capital expenditures included in rate base (producing ratepayer savings on the capital-related revenue requirement associated with these expenditures),[75] the wildfire mitigation portion of distribution rate base[76] continues to increase as new capital expenditures are authorized and layered over existing capital expenditures with long amortization periods, as shown in Table 5.[77]

Table 5: PG&E, SCE, and SDG&E Wildfire Mitigation Portion (%) of Distribution Rate Base (January 1)

	2019	2020	2021	2022	2023
PG&E	N/A	0.2%	2.4%	5.1%	9.6%
SCE	N/A	N/A	1.6%	3.1%	5.3%
SDG&E	2.0%	5.7%	6.0%	6.2%	6.4%

The wildfire mitigation portion of PG&E and SCE's rate base amounts show substantial increases over the 2021 – 2023 period[78] and the expectation is that this trend will continue in the near term.[79] As rate base grows, the capital-related revenue requirements corresponding to rate base also grow as the function of two effects--new capital expenditure spending and ongoing revenue requirement effects of previous capital expenditure spending--meaning that the wildfire-related capital revenue requirement may become a significant portion of the total revenue requirement in rates at a future point in time. Inclusion of a summary table of rate base by functional category with breakouts for wildfire mitigation infrastructure investment requests could facilitate more transparency and

[73] Covered conductor is a type of wildfire mitigation measure. Transportation electrification, transmission, and energy storage investments are also included in this list. *See* fourth quarter 2022 earnings presentation: https://s3.amazonaws.com/cms.ipressroom.com/406/files/20231/eix-fourth-quarter-2022-financial-results-presentation.pdf.

[74] For California Sempra (SDG&E and SoCalGas), only a reference to infrastructure is provided, "Sempra California is investing in infrastructure to create an increasingly safe and reliable system, support electrification, and deliver cleaner fuels." *See* fourth quarter 2022 earnings presentation: https://investor.sempra.com/static-files/2877408f-ae85-429e-a0c4-91d4e78a49aa.

[75] *See* wildfire-related costs subsection later in this chapter for more information about the AB 1054 equity rate base exclusion.

[76] Data series starts with the test year of each IOU's first GRC authorized after 2019 and is from IOU data responses to SB 695 Report data requests. Distribution rate base reflects net plant/capital additions only i.e. "other" distribution non-plant/capital additions rate base is not included. Wildfire mitigation portion of transmission rate base is not available.

[77] For example, PG&E undergrounding assets generally have depreciable lives of 49 years and overhead hardening assets generally have depreciable lives of 45 years.

[78] SDG&E rate base shows a similar rapid increase pattern over the 2019 – 2021 period.

[79] Near term is defined as out to 2026.

effective stakeholder scrutiny of IOU wildfire mitigation revenue requests in GRC and other proceedings.[80]

Return on Rate Base Revenue Requirement

Return on rate base revenue requirement, representing amounts paid to shareholders from ratepayers, forms part of the capital-related revenue requirement. Tables 3-4, above, show that this revenue requirement has been increasing at an average annual percent change greater than the assumed inflation rate of 4.1 percent for PG&E transmission rate base, and SCE and SDG&E distribution and transmission rate base.[81] Since 2016, distribution and transmission return on rate base revenue requirement has been increasing on average approximately 3 percent and 15 percent for PG&E, respectively, 10 percent and 5 percent for SCE, respectively, and 7 percent and 10 percent for SDG&E, respectively.

Since the authorized return on equity (ROE) – which is a key input used in part to calculate the rate of return on rate base – has only seen modest changes since at least 2006,[82] the return on rate base revenue requirement growth rate primarily reflects rate base growth.

Recent Policy Actions to Address Affordability

The CPUC reduced the IOUs' cost of capital in its recent decision on the IOUs' 2023 cost of capital applications, lowering the ROE by 25 basis points to reflect quantitative financial models, other macroeconomic trends, credit worthiness, and the risk profile of each individual utility.[83] This adjustment lowers the equity portion of the weighted average cost of capital used to calculate the rate of return on rate base revenue requirement.

Revenue Requirement Special Topics

As in the reports from the last several years, trends in wildfire-related costs and transportation electrification[84] costs embedded in distribution and transmission revenue requirements will be isolated in this year's report. This year's report also includes a closer look at cost shifts and cross-

[80] Rate base breakouts for transportation and building electrification infrastructure investments should similarly be included.
[81] Average annual inflation rate (2016 base year to 2023) is 4.1 percent, based on Consumer Price Index (CPI), California Region, All Items, All Urban Consumers, reported by the California Department of Finance (DOF), available here (CPI Forecast Data prepared in November 2022; 2022 & 2023 forecasted). While this inflation measure may not necessarily be representative of expected utility cost escalation, it provides a proxy for how inflationary effects of distribution and transmission return on rate base revenue requirements may flow down to affect affordability of customer rates.
[82] *See* the CPUC Return on Equity webpage for more information.
[83] *See* D.22-12-031.
[84] Building electrification costs are not presented as these costs are still at a nascent stage. *See* SCE's pending Building Electrification application A.21-12-009.

subsidies that may be present in Net Energy Metering tariffs and California Alternate Rates for Energy (CARE) program tariffs.[85]

Historical Wildfire-Related Costs

Extraordinary utility operations challenges have been introduced by climate change, most notably catastrophic wildfires that threaten distribution and transmission infrastructure brought on by heat and drought that make vegetation more flammable, among other causes. Historic wildfire-related legislation enacted in 2018 and 2019 forms the backdrop for the historical wildfire-related costs since 2019 presented here.

Legislative and Regulatory Background

SB 901 (Dodd, 2018) and AB 1054 (Holden, 2019) require electric utilities to prepare and submit wildfire mitigation plans (WMP) to the Office of Energy Infrastructure Safety (Energy Safety) which describe the level of wildfire risk in their service territories and how they intend to address those risks. The WMPs cover a three-year period with new comprehensive plans to be filed at least once every three years and annual updates to the plans in between. The upcoming 2023 three-year cycle is the second three-year cycle for which electrical corporations are required to submit WMPs.[86]

SB 901 and AB 1054 permitted the IOUs in 2019 to open memorandum accounts to track spending to implement their WMPs. The IOUs now forecast the majority of their WMP costs in their General Rate Cases. However, the IOUs are allowed to seek recovery of any incremental spending recorded in the memorandum accounts in their GRCs or through a separate application.[87] The CPUC also allows the IOUs to recover certain wildfire-related costs that are external to the activities described in the WMP, including for wildfire insurance premiums and recovering from catastrophic events. Wildfire insurance costs that are incremental to the insurance costs authorized in the GRCs may be tracked for recovery through the Wildfire Expense Memorandum Account (WEMA) for PG&E and SCE, and the Liability Insurance Premiums Balancing Account (LIPBA) for SDG&E.[88] The IOUs also track eligible costs to respond to catastrophic events, including wildfires, in their Catastrophic Event Memorandum Accounts (CEMA).[89] Permissible CEMA expenses include

[85] For CARE program and other legislative program cost data, *see* the 2022 AB 67 Report.
[86] The 2023 - 2025 IOU WMPs were submitted to Energy Safety March 27, 2023; cost data therein has not been reviewed for inclusion in this report at time of writing. *See* each IOU's 2023 WMP at: https://energysafety.ca.gov/what-we-do/electrical-infrastructure-safety/wildfire-mitigation-and-safety/wildfire-mitigation-plans/2023-wildfire-mitigation-plans/.
[87] For example, PG&E's A.22-12-009 seeks recovery of incremental wildfire mitigation spend, among other expenditures, recorded in balancing accounts and SCE A.22-06-003 requests recovery of incremental wildfire mitigation spending recorded in memorandum and balancing accounts; recovery of FERC-related costs is done in Transmission Owner rate cases.
[88] Wildfire-related liability costs are claims paid as a result of property losses, in addition to other incremental liability costs including higher-than-forecasted insurance premiums and legal fees.
[89] Permissible CEMA expenses include restoring utility services to customers; repairing, replacing, or restoring damaged utility facilities; and complying with government agency orders resulting from declared disasters.

restoring utility services to customers; repairing, replacing, or restoring damaged utility facilities; and complying with government agency orders resulting from declared disasters.

AB 1054 contains two separate benefits for ratepayers related to WMP capital spending. AB 1054 excludes the first $5 billion of the large IOUs' WMP capital spending[90] from earning a Return on Equity (ROE). This limits rate increases directly by eliminating the shareholder profit portion of the return on rate base of $5 billion in WMP capital spending. These equity rate base exclusions could save ratepayers as much as $2 billion that would otherwise be collected in rates over time.[91] AB 1054 also allows for this $5 billion capital spending to be securitized through a CPUC financing order rather than being financed through the more traditional unsecured bond offerings. This securitization benefits ratepayers by allowing the bonds to obtain a lower interest rate than would otherwise be available to finance WMP capital expenditures because the bonds are secured by a fixed recovery charge on customer bills.[92]

AB 1054 also created a $21 billion Wildfire Fund for excess liabilities resulting from utility-caused wildfires, funded equally by ratepayers and utility shareholders.[93] A non-bypassable charge (NBC) is collected from non-exempt ratepayers to support the fund, with CARE and Medical Baseline customers exempt from paying the NBC.

Costs in Rates

Since 2019 and as of fourth quarter 2022, the IOUs have been authorized[94] to collectively place in rates approximately $13 billion of wildfire mitigation costs to support the state's wildfire prevention efforts and approximately $7 billion for wildfire insurance premiums and catastrophic events costs.[95] Together, wildfire mitigation and wildfire insurance (and catastrophic events) costs are referred to as

[90] Of the $5 billion total in excluded capital expenditures, PG&E's share is $3.21 billion, SCE's is $1.575 billion, and SDG&E's is $215 million.
[91] Finding of Fact 2 of each CPUC Financing Order states the estimated Net Present Value (NPV) savings of each bond issuance authorized. D.20-11-007: $173 million; D.21-06-030: $633 million; D.21-10-025: $403 million; D.22-08-004: $659 million; D.23-02-023: $493 million. The CPUC also approved SDG&E AL 4078-E that demonstrated $84.3 million NPV savings.
[92] D.21-06-030 approved PG&E's first AB 1054 financing order totaling about $1.2 billion in AB 1054 CapEx of which bonds representing about $850 million were issued, and D.22-08-004 approved its second AB 1054 financing order totaling about $1.4 billion in AB 1054 CapEx of which bonds representing about $975 million were issued; D.20-11-007, D.21-10-025 and D.23-02-023 approved SCE's first, second and third (final) AB 1054 financing orders totaling about $1.575 million in AB 1054 CapEx of which bonds representing the same amount of CapEx were issued or are to be issued; Recovery bond financing costs apply to all AB 1054 securitizations.
[93] Utilities must meet certain conditions to participate in the fund.
[94] Includes CPUC and FERC authorizations, except for PG&E which declined to provide FERC-related wildfire insurance and catastrophic events data and SDG&E which states it is not able to provide FERC-related wildfire mitigation data because WMP is a CPUC-jurisdictional balanced program.
[95] PG&E insurance amount is total insurance, as general liability and wildfire liability insurance is not split in company records. PG&E indicates excess liability represents the primary component of general liability, and wildfire excess liability cost is greater than non-wildfire.

"wildfire-related" costs. Total wildfire-related costs placed in rates[96] between 2019 and 2022[97] are approximately $20 billion as shown in Table 6.[98]

Table 6: Total Wildfire-Related Costs in Rates
(2019 – 2022, Year-End, $ billions)

Utility	Total Wildfire-Related Costs in 2019 – 2022 Rates (sum of columns to right)	Total Wildfire Mitigation Costs in 2019 - 2022 Rates	Total Wildfire Insurance / Catastrophic Events Costs in 2019 – 2022 Rates
PG&E	**$11.4**	$7.8	$3.6
SCE	**$7.5**	$4.2	$3.3
SDG&E	**$1.0**	$0.5	$0.5
Total	**$19.9**	$12.5	$7.4

For PG&E and SCE, wildfire-related costs began to show up as wildfire-related revenue requirement in significant amounts relative to total revenue requirement starting in 2021. SDG&E shows a lower percentage of wildfire-related revenue requirement to total revenue requirement; however, SDG&E has been revamping and enhancing its wildfire prevention and mitigation measures since 2007 and cost figures may reflect a mature wildfire safety program.[99] Further, while PG&E and SCE have already begun collecting wildfire mitigation costs booked in memorandum accounts established by SB 901, SDG&E plans to file its request for recovery of similar costs later this year.[100]

Tables 7-9 show incremental revenue requirement reflected in 2019 - 2022 rates at year-end corresponding to each IOU's wildfire-related costs by CPUC and FERC jurisdiction. CPUC-jurisdictional wildfire-related costs are generally recovered through the distribution rate component; however, starting in the fourth quarter of 2020, all IOUs began recovered Wildfire Fund costs

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[96] Additional costs may have been incurred during the 2019 – 2022 period but may not have yet been placed in rates. There is not a 1:1 relationship between costs and revenue requirement placed in rates. *See* Tables 7- 9 for the equivalent revenue requirement in rates.
[97] Year-end data is used for this table and the tables that follow to capture all wildfire-related costs within the calendar year.
[98] SDG&E data through 2021 only; SDG&E declined to provide 2022 data stating that the data will be available when its 2022 Risk Spending Accountability Report is filed.
[99] *See* the 2021 SB 695 Report for additional detail about SDG&E operating expenses and capital costs incurred for wildfire prevention over the period 2007 – 2018.
[100] SDG&E plans to file a Track 2 as part of its GRC A.22-05-016 in September 2023 to request recovery of costs booked between 2019-2022 in its Wildfire Mitigation Plan Memorandum Account.

through a dedicated wildfire fund rate component.[101] Similarly, starting in 2021, PG&E and SCE began recovering securitized wildfire mitigation costs through a dedicated securitization rate component.[102] For each IOU, Figures 10-12 follow each table and show year-end 2022 total system-level revenue requirement place in rates at the total system level,[103] with the cross-hatched areas in the charts representing the 2022 data in the tables.

[101] The rate component is generally known as the Wildfire Fund non-bypassable charge; actual name varies by IOU; *see* AB 1054 discussion earlier in this section for more information.

[102] PG&E rate component is known as Wildfire Hardening Fixed Recovery Charge and SCE rate component is known as Fixed Recovery Charge; *see* AB 1054 discussion earlier in this section for more information.

[103] Total system-level revenue requirements come from both bundled and unbundled customers---in other words, all revenue requirements. Distribution revenue requirement includes the netting effect of the semi-annual Greenhouse Gas Revenue Return credited to eligible customers through the distribution rate component. Revenue requirement does not capture programs that result in a cross-subsidy between various customers groups such as the California Alternate Rates for Energy (CARE) surcharge between Non-CARE and CARE customers, which can add a significant amount to the PPP rate paid by Non-CARE customers. Pie chart percentages may not sum to 100% due to rounding.

PG&E Revenue Requirement in Rates

Table 7: PG&E Wildfire-Related Revenue Requirement by Distribution, Transmission and Non-Bypassable Charge Rate Components (2019 – 2022, Year-End, $ millions)

	2019		2020		2021		2022	
PG&E	Operating Expense	Capital-Related	Operating Expense	Capital-Related	Operating Expense	Capital-Related	Operating Expense	Capital-Related
Wildfire-Related Distribution[104]	$68.9	$4.7	$22.9	$275.5	$2,030.3	($14.6)	$2,373.6	$45.8
Wildfire Fund NBC	-	-	$427.3	-	$403.4	-	$457.0	-
Wildfire Hardening FRC NBC	-	-	-	-	-	$82.3	-	$81.7
Wildfire-Related Transmission[105]	-	-	$16.0	$1.5	$138.4	$15.4	$381.9	$73.7
Subtotal Wildfire-Related Rev Req	**$68.9**	**$4.7**	**$466.2**	**$277.0**	**$2,572.1**	**$83.1**	**$3,212.5**	**$201.2**
Total Wildfire-Related Rev Req		**$73.6**		**$743.2**		**$2,655.2**		**$3,413.7**
Total Rev Req		**$13,561.6**		**$14,145.9**		**$14,381.7**		**$15,105.9**
% Wildfire-Related Rev Req to Total Rev Req		**0.5%**		**5.3%**		**18.5%**		**22.6%**

Table 7, above, shows continued growth in the percentage of wildfire-related revenue requirement to total revenue requirement over the 2019 to 2022 period and shows in particular how significant the wildfire-related revenue requirement continues to be in 2022. The 2022 wildfire-related revenue requirement is primarily driven by operating expense: the 2022 attrition year amortization of 2020 GRC adopted costs,[106] 2022 wildfire liability insurance, Wildfire Fund insurance, and FERC-

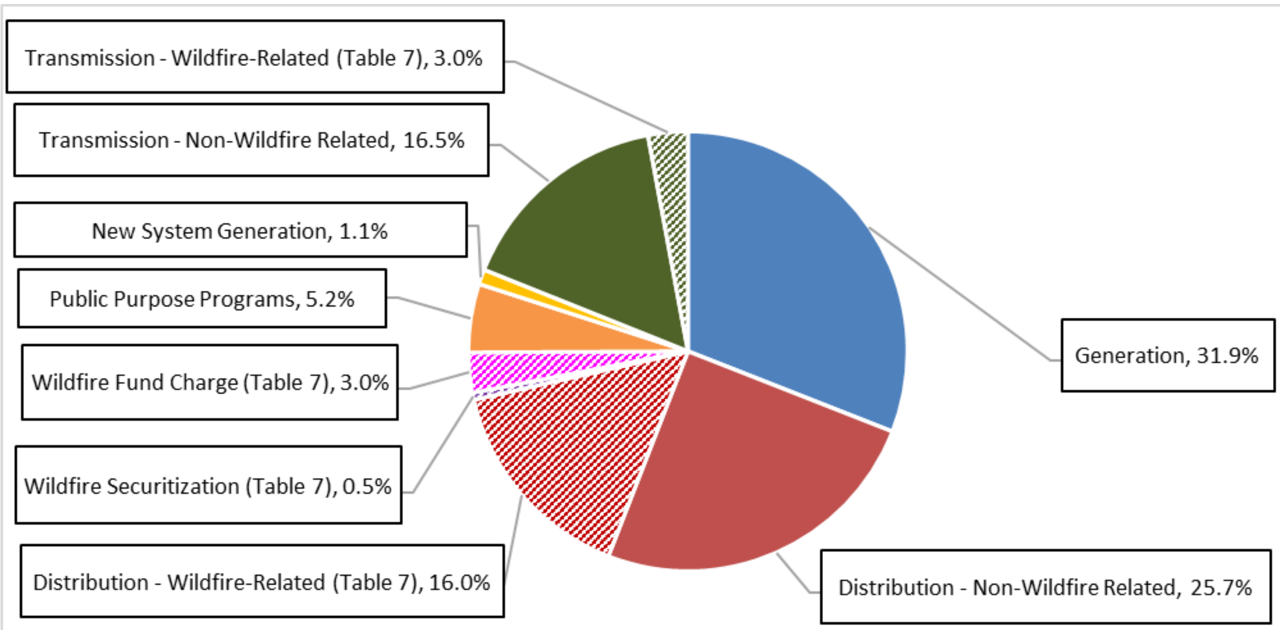
104 General Liability and Wildfire-Related insurance not split in company records.

105 Wildfire mitigation only; PG&E declined to provide FERC-related wildfire insurance and catastrophic events data.

106 *See* D.20-12-005; Per the Decision, PG&E is authorized to recover incurred costs up to the annual authorized cost cap of 120 percent for vegetation management (VM) and up to 115 percent for wildfire mitigation (WM) through a Tier 2 advice letter filing.

jurisdictional wildfire mitigation costs. Figure 10, below, shows for year-end 2022 approximately 23 percent in wildfire-related revenue requirement as part of the composition of PG&E's total system revenue requirement.[107]

Figure 10: PG&E 2022 Year-End Total System Revenue Requirement by Rate Component with Additional Wildfire-Related Revenue Requirement Breakout



[107] Not shown: ND -0.1%, CTC 0.1%, ECRA (FERC Refund) -2.2%, DWR Refund -0.9%.

SCE Revenue Requirement in Rates

Table 8: SCE Wildfire-Related Revenue Requirement by Distribution, Transmission and Non-Bypassable Charge Rate Components (2019 – 2022, Year-End, $ millions)

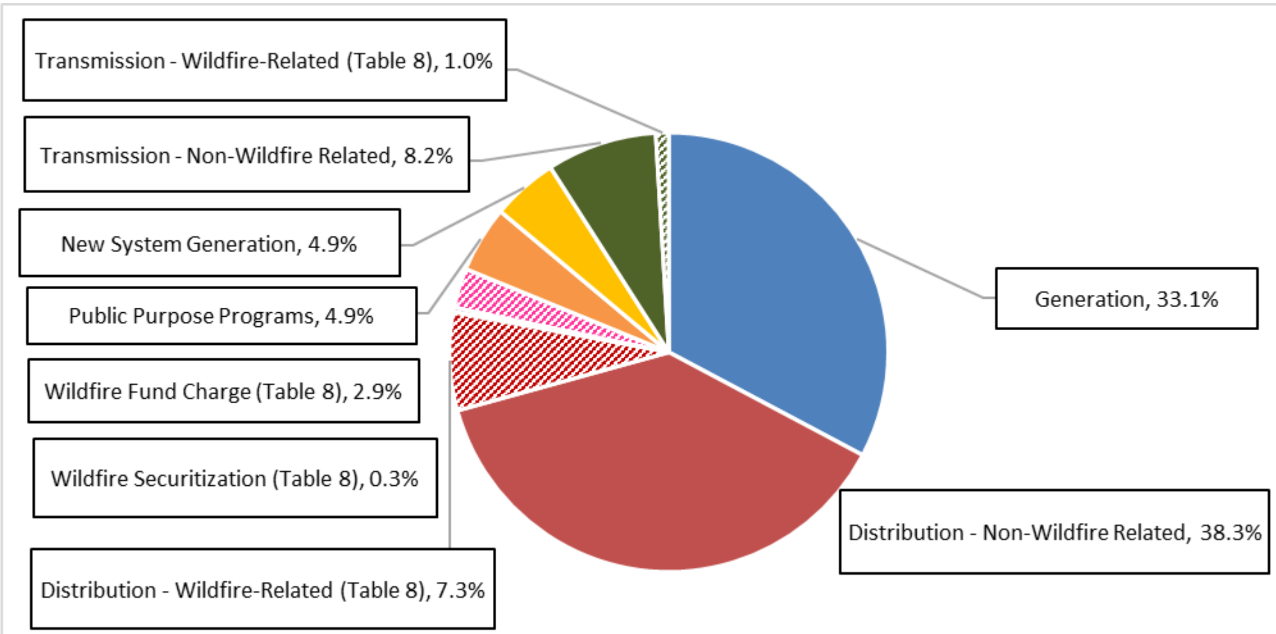
SCE	2019		2020		2021		2022	
	Operating Expense	Capital-Related	Operating Expense	Capital-Related	Operating Expense	Capital-Related	Operating Expense	Capital-Related
Wildfire-Related Distribution[108]	$287.5	-	$409.6	-	$1,177.2	$69.1	$1,003.7	$101.0
Wildfire Fund NBC	-	-	$428.1	-	$393.1	-	$447.0	-
Wildfire FRC NBC	-	-	-	-	-	$19.3	-	$51.0
Wildfire-Related Transmission[109]	$1.0	-	$168.1	$0.6	$57.2	$2.4	$146.8	$0.1
Subtotal Wildfire-Related Rev Req	**$288.5**	**-**	**$1,005.8**	**$0.6**	**$1,627.5**	**$90.8**	**$1,597.5**	**$152.1**
Total Wildfire-Related Rev Req		**$288.5**		**$1,006.4**		**$1,718.3**		**$1,749.6**
Total Rev Req		**$11,120.6**		**$12,665.3**		**$14,294.4**		**$15,170.3**
% Wildfire-Related Rev Req to Total Rev Req		**2.6%**		**7.9%**		**12.0%**		**11.5%**

Table 8, above, shows continued growth in the percentage of wildfire-related revenue requirement to total revenue requirement over the 2019 to 2021 period and a leveling-off in 2022 as compared to 2021. The 2022 wildfire-related revenue requirement is primarily driven by operating expense: the 2022 attrition year amortization of 2021 GRC adopted costs and wildfire-related recorded memorandum and balancing account costs,[110] wildfire liability insurance, and Wildfire Fund insurance. Figure 11, below, shows for year-end 2022 the approximately 12 percent in wildfire-

[108] Vegetation management does not distinguish between wildfire and non-wildfire vegetation management.
[109] *Ibid*.
[110] *See* D.21-08-036, D.21-01-012, and D.22-06-032.

related revenue requirement as part of the composition of SCE's total system revenue requirement.[111]

Figure 11: SCE 2022 Year-End Total System Revenue Requirement by Rate Component with Additional Wildfire-Related Revenue Requirement Breakout



[111] CPUC Fee not included. Not shown: ND 0.0%, DWR Refund -1.0%.

SDG&E Revenue Requirement in Rates

Table 9: SDG&E Wildfire-Related Revenue Requirement by Distribution, Transmission and Non-Bypassable Charge Rate Components (2019 – 2022, Year-End, $ millions)

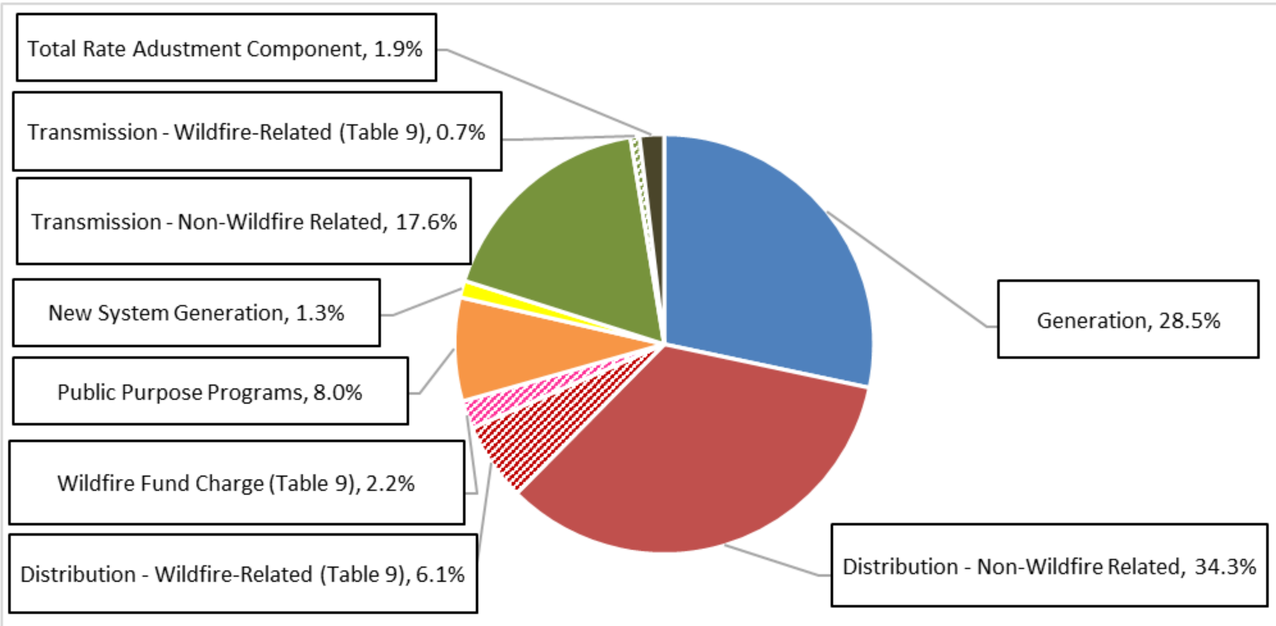
	2019		2020		2021		2022	
SDG&E	Operating Expense	Capital-Related	Operating Expense	Capital-Related	Operating Expense	Capital-Related	Operating Expense	Capital-Related
Wildfire-Related Distribution	$99.7	$11.8	$104.2	$37.4	$162.9	$44.7	$206.7	$49.4
Wildfire Fund NBC	-	-	$22.6	-	$90.2	-	$92.1	-
Wildfire FRC NBC	-	-	-	-	-	-	-	-
Wildfire-Related Transmission[112]	$14.7	-	$18.3	-	$23.6	-	$30.0	-
Subtotal Wildfire-Related Rev Req	**$114.4**	**$11.8**	**$145.1**	**$37.4**	**$276.7**	**$44.7**	**$328.8**	**$49.4**
Total Wildfire-Related Rev Req		**$126.2**		**$182.5**		**$321.4**		**$378.2**
Total Rev Req		**$4,211.7**		**$4,142.0**		**$4,334.8**		**$4,215.5**
% Wildfire-Related Rev Req to Total Rev Req		**3.0%**		**4.4%**		**7.4%**		**9.0%**

Table 9, above, shows continued growth in the percentage of wildfire-related revenue requirement to total revenue requirement over the 2019 to 2022 period.[113] The 2022 wildfire-related revenue requirement is primarily driven by operating expense: the 2022 attrition year amortization of 2019 GRC adopted costs as modified,[114] wildfire liability insurance, and Wildfire Fund insurance. Figure

[112] Wildfire Insurance only; SDG&E declined to provide FERC-related wildfire mitigation data.
[113] 2021 and 2022 total revenue requirements are from AL 3928-E (Attachment C, Present Revenue Requirements) and AL 4004-E (Attachment B, Proposed Revenue Requirements), respectively, both of which have the Tree Mortality Non-Bypassable Charge revenue requirement excluded due to confidentiality.
[114] *See* D.19-09-051 and D.21-05-003.

12, below, shows for year-end 2022 the approximately 9 percent in wildfire-related revenue requirement as part of the composition of SDG&E's total system revenue.[115]

Figure 12: SDG&E 2022 Year-End Total System Revenue Requirement by Rate Component with Additional Wildfire-Related Revenue Requirement Breakout



Wildfire-Related Portion of Monthly Bill

Table 10 shows the wildfire-related portion of a bundled residential Non-CARE[116] customer average monthly bill resulting from the wildfire-related revenue requirement represented in Figures 10-12.[117]

[115] CPUC Fee not included. Not shown: ND 0.0%, CTC 0.5%, DWR Refund -1.2%.
[116] 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.
[117] Year-end 2022 rates in effect. Typical Non-CARE customer using 500 kWh (PG&E climate zone S, SCE climate zone 9) and 400 kWh (SDG&E Inland climate zone). Bills are for illustrative purposes only.

Table 10: PG&E, SCE, and SDG&E Wildfire-Related Portion of Year-End 2022 Average Monthly Bill, Bundled Residential Non-CARE Customers

	Total Bill	Wildfire-Related Portion ($)	Wildfire-Related Portion (%)
PG&E	$167.14	$28.99	17.3%
SCE	$153.32	$15.36	10.0%
SDG&E	$159.15	$13.77	8.7%

Climate change, primarily caused by the burning of fossil fuels, is increasing the frequency and severity of wildfires in California.[118] As the wildfire-related portion of customer bills approaches 20 percent for some Californians, it may be time to shift ratepayer cost burdens caused by climate change-driven wildfires to non-ratepayer funding sources. Previous conversations on this topic have centered on wildfire spending being funded through taxpayer dollars instead of ratepayer dollars, a progressive approach with higher-income households paying a higher share of wildfire costs.[119]

Another approach would be to include wildfire mitigation costs in a possible residential income-graduated fixed charge in the ongoing Track A of the CPUC's Demand Flexibility Proceeding.[120] Party testimony is to include income-graduated fixed charge proposals with higher-income households paying a higher share of fixed charges.[121] In vetting these proposals, the CPUC may also consider the possible classification of wildfire mitigation costs[122] as fixed costs in calculating an income-graduated fixed charge.

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

[119] *See* Severin Borenstein's 2021 Affordability Proceeding En Banc comments summarized in the 2021 SB 695 Report, page 120 and PG&E's 2022 Affordability Proceeding En Banc comments summarized in the 2022 SB 695 Report, page 52 (with respect to operating expenses, not capital-related costs).

[120] Track A will establish an income-graduated fixed charge for residential rates for all IOUs in accordance with AB 205; *See* docket for R. 22-07-005. *See* the Net Bill Tariff section later in this chapter for more discussion of the residential income-based fixed charge track of the Demand Flexibility Proceeding.

[121] Opening testimony is due April 7, 2023; Reply testimony is due June 2, 2023.

[122] For example, parties may consider classifying wildfire mitigation costs as non-marginal distribution costs when developing proposals.

Historical Transportation Electrification Program Costs

In addition to traditional IOU objectives of reliable, safe, and affordable electric service, legislative mandates to pursue clean energy and other policy objectives can add costs that result in higher revenue requirements. Clean energy transportation electrification legislative mandates along with private sector innovation will propel the transition to a fully electrified transportation sector over the next decade, and significant upgrades to the distribution grid will be necessary to accommodate charging demand. There is the potential for these costs to be a key driver of rate increases.

Legislative and Regulatory Background

The CPUC is responding to several legislative mandates and gubernatorial directives to support and accelerate widespread TE.[123] SB 350 (De León, 2015) directed the CPUC to require the IOUs to submit applications for programs that leverage ratepayer funding to support electric vehicle (EV) adoption.[124] To date, the CPUC has authorized the IOUs to implement many TE programs to help meet California's zero-emission vehicle (ZEV) targets of five million ZEVs on the road by 2030, 250,000 installed publicly available EV charging stations, and 200 publicly available hydrogen fueling stations in the state by 2025[125] as well as to help meet California's goals toward requiring all in-state sales of new passenger vehicles be zero-emission by 2035, all medium- and heavy-duty vehicles in the state be zero-emission by 2045, and all drayage trucks and off-road vehicles and equipment be zero-emission by 2035, where feasible.[126]

Additionally, AB 841 (Ting, 2020) directs the establishment of new electric rules or tariffs that authorize each IOU to design and deploy all utility-side electrical distribution infrastructure for customers installing separately metered EV charging. This changes the CPUC practice of authorizing utility-side, electrical distribution infrastructure needed to charge EVs[127] on a case-by-case basis through individual program applications, to authorization of that infrastructure and associated design, engineering, and construction costs on an ongoing basis in an IOU's GRC. The bill also makes permanent the exemption to CPUC Electric Rules 15 and 16, which allow service facility upgrade costs resulting from residential EV charging to be treated as a common cost paid for by all ratepayers. New EV infrastructure rules pursuant to AB 841 were approved in October

[123] SB 350 defined TE as any vehicle fueled by electricity generated outside of the vehicle, including light-duty vehicles, medium- and heavy-duty vehicles, off-road vehicles, and shipping vessels.
[124] Such as multi-unit dwellings, workplaces, destination centers, disadvantaged communities, and low/medium income residential communities.
[125] Executive Order (E.O.) B-48-18.
[126] E.O. N-79-20.
[127] Section 740.19(b) defines "electrical distribution infrastructure" as including poles, vaults, service, drops, transformers, mounting pads, trenching, conduit, wire, cable, meters, other equipment as necessary, and associated engineering and civil construction work.

2021[128] and the exemption to Rules 15 and 16 for residential customers was approved in December 2021.[129]

The Decision on Transportation Electrification Policy and Investment, approved in November 2022, establishes a framework with budget and policy directives to ensure a structured approach to TE investment for all electric IOUs in the state, through five-year funding cycles.[130] The Decision authorizes up to $1 billion for a statewide Funding Cycle One (FC1) program, which will begin on January 1, 2025. $600 million in funding will be available for the first three years of the program, with the remaining funds authorized pending a Mid-Cycle Review to determine whether additional funding is needed. The IOUs will disburse funds, based on their percentage of 2024 electric sales, to a statewide third-party Program Administrator, who will design and administer the FC1 program. The FC1 program will fund behind-the-meter infrastructure rebates, technical assistance, and marketing, education, and outreach. By using a rebate structure, the program eliminates the opportunity for IOU ownership of behind-the-meter infrastructure, which is expected to result in ratepayer savings in the long run.

In addition to TE program expenses, in their GRCs the IOUs may file for recovery of distribution capacity costs related to EV load growth. The utilities began implementation of their EV Infrastructure Rules in April 2022, and the CPUC received data from the utilities' first year of implementation of the rules in April 2023. As they did not yet have data to inform their EV Infrastructure Rules revenue requirements, PG&E's and SDG&E's GRC proposals both utilize high-level TE related electric distribution infrastructure forecasts to develop their cost estimates. It is anticipated that SCE's 2025 GRC application will identify reliable TE related electric distribution infrastructure revenue requirement forecasts, which will not only include data from one-year of EV Infrastructure Rules adoption, but also include EV load forecasts that align with the 2022 Integrated Energy Policy Report (IEPR) update and current state TE regulations and other policies.

[128] *See* Resolution E-5167 (large IOUs) and Resolution E-5168 (small and multi-jurisdictional utilities).
[129] *See* D.21-12-033.
[130] *See* D.22-11-040.

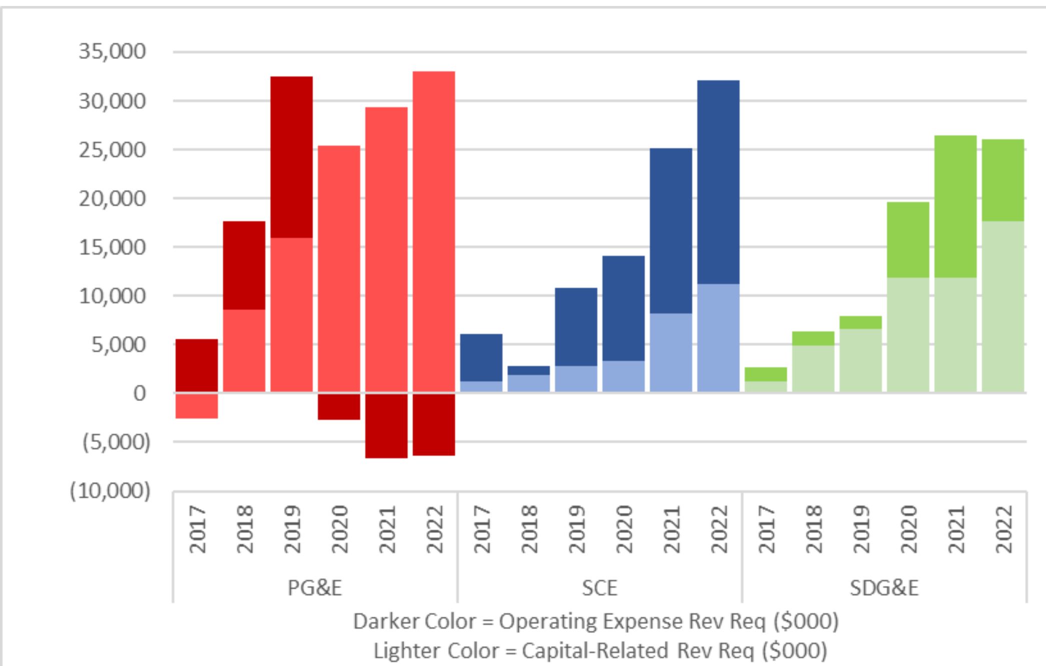
Costs in Rates

As of fourth quarter 2022, the CPUC has authorized the large electric IOUs to spend approximately $2.4 billion on EV charging infrastructure to support the state's TE goals. Out of the authorized IOU funding to date, $347 million has been spent[131] by PG&E, SCE, and SDG&E and $2.053 billion is still available for TE investment.

Revenue Requirement in Rates

Figure 13 shows for each IOU the relative share of the total operating expense and total capital-related revenue requirement[132] reflected in 2017 - 2022 rates corresponding to each IOU's transportation electrification program costs.[133] Operating expense revenue requirement may include balancing accounts that reflect negative (over-collected) balances. A capital-related amount may be negative due to first year depreciation flow-through.[134]

Figure 13: PG&E, SCE, and SDG&E Transportation Electrification Programs Revenue Requirement in Rates (2017 – 2022, Year-End, $ millions)



Transportation Electrification Portion of Monthly Bill

As indicated in previous SB 695 reports, TE programs continue to have modest impacts on bundled residential average rates, and the TE portion of forecasted bundled residential average rates is not expected to grow significantly in the near-term.[135] Table 11 shows the transportation electrification portion of a bundled residential Non-CARE[136] customer average monthly bill in 2022.[137]

Table 11: PG&E, SCE, and SDG&E TE Programs Portion of Year-End 2022 Average Monthly Bill, Bundled Residential Non-CARE Customers

	Total Bill	TE Program Portion ($)	TE Program Portion (%)
PG&E	$167.14	$0.23	0.1%
SCE	$153.32	$0.30	0.2%
SDG&E	$159.15	$0.95	0.6%

While the TE portion of Non-CARE customer bills is currently small, it is expected that at some point in the future a progressive approach to TE cost recovery may be needed as spending ramps up, with higher-income households paying a higher share of TE costs. This approach could be considered in the ongoing Track A (residential income-based fixed charge track) of the CPUC's Demand Flexibility Proceeding.[138] Party testimony is to include income-graduated fixed charge proposals with higher-income households paying a higher share of fixed charges.[139] In vetting these income-graduated fixed charge proposals, the CPUC may also consider the classification of transportation electrification and other grid infrastructure costs as fixed costs to promote decarbonization policies.[140]

California is undertaking a tremendous effort to accelerate TE infrastructure deployment in the coming years to meet the state's TE goals. The scale of the challenge is highlighted in the CEC Staff's first *Assembly Bill (AB) 2127 Electric Vehicle Charging Infrastructure Assessment* report, released in 2021,[141] which estimates that 1.5 million chargers will be needed by 2030 to support Governor Newsom's

131 This figure includes spending by all three IOUs as of December 2022.

132 There is not a 1:1 relationship between costs and revenue requirement placed in rates. Only a fraction of capital costs are reflected in revenue requirement placed in rates, *see* capital-related revenue requirement explanation earlier in this section.

133 SDG&E operating expense data reflects correction to previous years' data to reflect that SDG&E's authorized revenue requirements do not include balancing account balances.

134 For new capital spending, under normal tax ratemaking treatment, the benefit of the tax deduction "flows-through" to customers in the first year the capital asset is in service, with the tax benefit paid back over time as the utility receives revenue to amortize the capital asset ("flow-back").

135 Near-term defined as out to 2026.

136 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.

137 Year-end 2022 rates in effect. Typical Non-CARE customer using 500 kWh (PG&E climate zone S, SCE climate zone 9) and 400 kWh (SDG&E Inland climate zone). Bills are for illustrative purposes only.

138 Track A will establish an income-graduated fixed charge for residential rates for all IOUs in accordance with AB 205; *See* docket for R. 22-07-005. *See* the Net Bill Tariff section later in this chapter for more discussion of the residential income-graduated fixed charge track of the Demand Flexibility Proceeding.

139 Opening testimony is due April 7, 2023; Reply testimony is due June 2, 2023.

140 For example, parties may consider classifying various transportation electrification programs and policy mandate costs collected through distribution rates as non-marginal distribution costs when developing proposals.

141 At time of writing, the 2023 edition of the biennial AB 2127 Report has not been released.

goals for light-duty vehicle electrification. Considering that the state had 188,000 public chargers installed or planned as of September 30, 2020, there is a substantial gap in public charging infrastructure that will need to be funded through a combination of private, taxpayer, and ratepayer funding.[142]

While the report urges continued public financing of chargers and infrastructure in the near-term, it also highlights the importance of devising innovative financing mechanisms that can reduce the burden of these investments on ratepayers and the public, and of finding ways to utilize charging infrastructure to benefit the grid, and thus potentially reduce infrastructure upgrade costs elsewhere. Examples of public funding include: 1) CEC California Electric Vehicle Infrastructure Project (CALeVIP), an incentive program that provides funds for EV charger installations across the state;[143] 2) EnergIIZE, a CEC-funded infrastructure program for the medium and heavy-duty vehicle sector; 3) federal National Electric Vehicle Infrastructure Plan (NEVI) funding for EV charge corridors authorized through the 2021 Infrastructure and Jobs Act (IIJA); and 4) Low Carbon Fuel Standard (LCFS) credit revenue generated from EVs that is used in many cases to support additional charging infrastructure.

California Alternative Rates for Energy (CARE) Program Costs

The CARE program is a low-income energy rate assistance program that provides a discount on energy bills to qualifying low-income households with incomes at or below 200 percent of the Federal Poverty Guideline.[144] The CARE program seeks to provide financial assistance as a beneficial public good to lower customers' bills. CARE is funded by non-exempt customers (all customers except for CARE customers) as part of a statutory "public purpose program surcharge" that appears on monthly utility bills.[145] Currently the CARE program provides a rate discount ranging from approximately 30 percent to 35 percent on electric bills and 20 percent on natural gas bills.[146]

Legislative and Regulatory Background

The CARE program was established in 1989 by California Public Utilities Code Sections 739.1 and 739.2, with AB 327 (Perea, 2013) mandating the restructuring of the CARE discount rate to what it

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142 Crisostomo, Noel, Wendell Krell, Jeffrey Lu, and Raja Ramesh. January 2021. Assembly Bill 2127 Electric Vehicle Charging Infrastructure Assessment: Analyzing Charging Needs to Support Zero-Emission Vehicles in 2030. California Energy Commission. Publication Number: CEC-600-2021-001.

143 CALeVIP is currently funded for $124.9 million through CEC funding, with $32 million in co-founding partner contributions.

144 In addition to the CARE program, the Family Electric Rate Assistance (FERA) program provides families of three or more whose household income slightly exceeds the CARE allowances with an 18 percent discount on their electricity bill. Only the CARE program is discussed here.

145 For certain non-bypassable charges (NBC) from which CARE customers are exempt, non-exempt customers also pay what would have been the CARE customer portion of the NBC in the form of higher rates for the applicable NBCs.

146 PG&E and SDG&E electric effective discounts are 35 percent and SCE electric effective discount is 32.5 percent.

is today. As economic hardship for California residents has increased over the past few years, participation in CARE has increased as shown in Table 12.[147]

Table 12: PG&E, SCE, SDG&E, and SoCalGas CARE Program Participation (2016 – 2022, Year-End, Millions of Electric and Gas Customers Enrolled)

	2016	2017	2018	2019	2020	2021	2022
PG&E	1.423	1.406	1.376	1.383	1.573	1.551	1.470
SCE	1.236	1.223	1.206	1.185	1.424	1.402	1.165
SDG&E	0.271	0.282	0.288	0.299	0.336	0.321	0.350
SoCalGas	1.571	1.564	1.616	1.610	1.767	1.816	1.782
Total	4.501	4.475	4.486	4.477	5.100	5.090	4.767

In 2022, the program provided approximately $2.4 billion in electric and gas annual subsidies and served approximately 4.8 million low-income customers statewide.[148]

Costs in Rates

The CARE subsidy as calculated by the IOUs (known as the effective discount) currently consists of both a line-item discount subsidy and rate exemptions subsidy.

Effective Discount = Line Item Discount + Rate Exemptions

A higher CARE line-item subsidy does not result in a higher revenue requirement *for the utility* as revenue is collected from Non-CARE customers[149] and transferred to CARE customers. This cross-subsidy increases the rates that Non-CARE customers pay through the PPP rate component used to collect the surcharge for the line-item discount subsidy given on the CARE customer bill.

The IOUs currently net the rate exemption portion of the subsidy[150] from the effective discount total subsidy to obtain the line-item discount portion of the subsidy. For example, if a utility has an effective discount of 35 percent and the rate exemptions total about 4 percent, the line item discount currently will be about 31 percent. In this example, the 4 percent in rate exemptions could consist of rate components from which CARE customers are exempt such as the Wildfire Fund non-bypassable charge (NBC) and the CARE surcharge itself.[151] It is unclear why the IOUs currently bundle the rate exemption subsidy as part of the CARE Program subsidy when CARE Program language in statute[152] does not appear to suggest that the rate exemptions should be considered part

[147] *See* IOU ESA-CARE December Monthly Reports, posted to docket A.19-11-003.
[148] *Id.* Some customers are enrolled in more than one program; for example, SCE for electricity and SoCalGas for natural gas.
[149] Includes all Non-CARE residential customers and all other non-residential customers.
[150] These rate exemptions increase the various CARE-exempt non-bypassable charge rate components that Non-CARE customers pay to collect what would have been the CARE customer portion if the CARE customer were not exempted by statute.
[151] CARE customers are exempt from paying the CARE surcharge. For all others, the CARE surcharge is calculated on an equal-cents-per-kWh basis based on forecasted volumetric sales to all non-exempt customers.
[152] *See* Public Utilities Code §739.1.

of the CARE Program effective discount. In other words, the rate exemptions exist completely separately (in different statutes) as just that, rate exemptions, not CARE Program benefits.

AB 205, enacted in 2022, requires, among other things, that the effective discount not reflect any charges for which CARE customers are exempted: that is, that the effective discount should not reflect the rate exemptions.[153]

Effective Discount = Line Item Discount

In the previous example given, this would mean that the line-item discount would not be reduced by the rate exemptions and would be the full 35 percent.[154] CARE rate exemptions would continue to be in effect as indicated in statute for each applicable rate exemption.[155] For large IOUs, the average monthly Non-CARE customer bill impact of making the CARE Surcharge Portion Effective Discount = Line-Item Discount is likely to increase bills by about $1 to $2 per month.

Table 13 shows for each electric IOU the current[156] estimated CARE surcharge portion of a bundled residential customer average monthly bill.[157] The PPP rate component,[158] through which Non-CARE customers provide funds for the CARE surcharge, and through which both CARE and Non-CARE customers fund public purpose programs[159] is also shown.[160]

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153 *See* Public Utilities Code §739.1(c)(1). The effective discount is also not to include discounts to fixed charges or other rates paid by non-CARE customer, or bill savings resulting from participation in other programs, including the medical baseline allowance pursuant to subdivision (c) of Section 739.

154 The CPUC is examining this and other AB 205 requirements in the Demand Flexibility Proceeding, *see* docket for R. 22-07-005. *See* the Net Bill Tariff section later in this chapter for more discussion of the Demand Flexibility Proceeding.

155 For example, Public Utilities Code § 850.1(i) expressly states that fixed recovery charges must not be imposed on CARE or FERA customers.

156 Rates effective January 1, 2023.

157 PG&E rate exemptions: CARE Surcharge portion of PPP, SGIP portion of PPP, Wildfire Fund, and Wildfire Hardening Charge; SCE rate exemptions: WF Bond, WF Securitization, DWR Bond Refund, CARE Non-CARE Surcharge; SDG&E rate exemptions: CARE Surcharge (includes CARE program/discount, FERA, CSI, Food Bank, RUBA); VGI, DWR-BC, WF-NBC, 50% Minimum Bill or BSF (as applicable).

158 Inclusive of the PPP Surcharge (Non-CARE customers only).

159 Public purpose programs include, but are not limited to: Energy Efficiency, the Energy Savings Assistance (ESA) program and the Electric Program Investment Charge (EPIC) program. The ESA program provides low-income weatherization assistance; the EPIC program is a research, development and demonstration (RD&D) program that funds a broad portfolio of innovations seeking to advance the frontiers of energy science and technology.

160 Bill figures are rounded. 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.

Table 13: PG&E, SCE, and SDG&E PPP Portion and CARE Program Surcharge Portion of Current Monthly Electric Bill, Bundled Residential Customers (January 1, 2023)

Residential Customer	Total Bill	PPP Portion (inclusive of CARE Surcharge)	CARE Surcharge Portion
PG&E Non-CARE	$173	$13	$7
PG&E CARE	$110	$5	N/A
SCE Non-CARE	$170	$10	$4
SCE CARE	$119	$6	N/A
SDG&E Non-CARE	$183	$10	$7
SDG&E CARE	$119	$6	N/A

With the PPP portion of Non-CARE customer bills approaching 8 percent and the PPP portion of CARE customer bills around 5 percent for some Californians, a progressive approach to PPP funding may be needed, with higher-income households paying a higher share of PPP costs. This approach could be considered in Track A (residential income-based fixed charge track) of the CPUC's Demand Flexibility Proceeding.[161] Party testimony is to include income-graduated fixed charge proposals with higher-income households paying a higher share of fixed charges.[162] For example, party proposals classify PPP charges as a fixed cost to be recovered as a fixed charge on an income-graduated basis.

Recent Policy Actions to Address Affordability

CARE program enrollment allows CARE program customers to participate in other income assistance programs or program pilots. In December 2022, the CPUC approved the large electric and gas IOUs' Percentage of Income Payment Plan (PIPP) pilots.[163] For eligible customers enrolled in CARE, the PIPP pilots set current[164] monthly electric and bill payment amounts at an affordable

161 Track A will establish an income-graduated fixed charge for residential rates for all IOUs in accordance with AB 205; *See* docket for R. 22-07-005. *See* the Net Bill Tariff section later in this chapter for more discussion of the residential income-graduated fixed charge track of the Demand Flexibility Proceeding.

162 Opening testimony is due April 7, 2023; Reply testimony is due June 2, 2023.

163 *See* Resolution E-5200. Community Choice Aggregators in each IOU's service territory will be participating in the PIPP pilot as well.

164 PIPP bill caps only apply to current charges and not past-due charges.

percentage of four percent of participants' monthly income.[165] Pilot enrollment for eligible customers is currently underway.[166]

Additionally, customers enrolled in CARE or Family Electric Rate Assistance (FERA) are eligible for an Arrearage Management Plan (AMP). The AMP program will forgive 1/12 of a customer's eligible utility debt after each on-time payment of their current bill. After 12 on-time payments of individual monthly bills, the debt is fully forgiven (up to $8,000 per customer). In order to be eligible for this plan, a residential customer must meet all the following eligibility requirements:

- Be enrolled in one of the IOUs' financial assistance programs, CARE or FERA.
- Owe at least $500 or more on a combined gas and electric bill, or owe at least $250 or more on a gas bill (applies to gas-only customers).
- Be more than 90 days past due.
- Be an IOU customer for at least 6 months, and have made at least one on-time payment.

Net Energy Metering and Net Billing Tariffs Cost Shifts

Net energy metering (NEM) tariffs and net billing tariffs[167] (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. Since implementing NEM over 25 years ago, California has witnessed the evolution of the customer-sited rooftop solar industry, resulting in the installation of over 12 gigawatts of clean distributed energy resources.[168]

Legislative and Regulatory Background

California's NEM tariffs started in 1997, prompted by SB 656 (Alquist, 1995). The tariffs allow customers who install eligible renewable electrical generation facilities to serve onsite energy needs and receive credits on their electric bills for surplus energy sent to the electric grid. Almost all customer-sited, grid-connected solar PV in California is interconnected through NEM tariffs. The NEM program is required by statute to ensure that the tariff is based on the costs and benefits of the distributed generation systems, that it achieves various equity-related aims, and that customer-sited renewable distributed generation continues to grow sustainably.[169]

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[165] Reference household income set at two levels, resulting in a 4% cap of $109/month for the lowest level and $37/month for the higher level. These amounts are further split by electric and gas service at a 75/25 ratio.

[166] Pilot enrollment is limit to customers who are enrolled in the CARE program and who either (i) are located in one of the zip codes with the highest rates of recurring disconnections prior to the disconnections moratorium, or (ii) have been disconnected 2 or more times during the 12 months prior to the disconnections moratorium.

[167] Includes subtariffs.

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

[169] *See* Public Utilities Code §2827.1(b)(1), §2827.1(b)(3), and §2827.1(b)(4).

The first NEM design, now known colloquially as "NEM 1.0," was revised in 2016 per AB 327 (Perea, 2013) when the CPUC adopted the NEM successor tariff now referred to as "NEM 2.0."[170] Customers on NEM 2.0 pay for their cost to connect to the grid, take service on a time-of-use (TOU) rate plan,[171] and pay certain non-bypassable charges[172] that cannot be offset with surplus energy credits, in order to contribute a portion of their fair share of the costs of public purpose programs and other initiatives.

In 2022, the CPUC reformed NEM policy and adopted a successor NBT design that balances multiple statutory requirements and the needs of the electric grid, the environment, NEM participants, and all other ratepayers.[173] The NBTs seek to reduce greenhouse gas emissions and increase grid reliability by improving alignment of tariff price signals with the electric grid's conditions, both day and night, and by incentivizing adoption of combined solar and storage systems. The new tariffs also implement revisions that offer customers in low-income households more access to distributed generation systems, including solar systems paired with storage.

Costs in Rates

The NBT Decision found that a significant and growing cost shift from participating solar customers to non-participants exists in the NEM tariffs and, to a lesser extent, remains in the adopted NBTs. The record in the NBT proceeding showed that monthly bill savings is a major factor in customers deciding to install a solar system, and the NBT decision determined that a nine-year simple payback[174] for a stand-alone solar system — equivalent to nearly $100 in monthly bill savings — presents a balanced approach to partially reduce the cost borne by non-solar customers while ensuring customer-sited renewable distributed generation continues to grow sustainably.[175] While the NEM 1.0 and NEM 2.0 tariffs and their resulting cost shifts were not eliminated, aspects of the new NBTs, including more accurate compensation for exported energy,[176] should gradually reduce the cost shift, marking a major step toward equity in rates and bills.[177]

The NEM 1.0 and 2.0 cost shift is comprised of two elements: (1) overcompensation for exported energy and (2) avoidance of fixed costs. These cost shifts are not immediately apparent in rates.

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[170] *See* D.16-01-044.
[171] 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.
[172] D.16-01-044 lists the non-bypassable charges as Public Purpose Program Charge; Nuclear Decommissioning Charge; Competition Transition Charge; and Department of Water Resources bond charges. Other non-bypassable charges may be statutorily required.
[173] *See* D.22-12-056.
[174] Simple payback equals the cost of the system divided by first-year bill savings.
[175] NBT customers with a solar system paired with storage will likely have a shorter payback period and may see greater monthly bill savings than participating customers with a stand-alone solar system.
[176] This increased payback period is generally a function of reduced NEM export compensation rates (for similarly sized systems). The decision provides a glide path with a higher adder to ensure eligible low-income customers achieve the same nine-year payback target for stand-alone solar systems that all other residential customers receive.
[177] The NBT is to be fully implemented within 12 months of the NBT Decision, with PG&E permitted to extend implementation for non-residential customers for up to 18 months.

due to a "rate creep" effect that shows up as follows: (1) generation rates paid by all ratepayers reflect a higher passed-through cost due to NEM export compensation rates being higher than the benefits they provide to the electrical system;[178] and (2) distribution rates[179] paid by all ratepayers reflect a higher cost due to the ability of NEM customers to avoid fixed costs, particularly grid costs,[180] which then become the responsibility of non-participating ratepayers, many of which are low-income customers. The NBT Decision noted that certain parties contended the NEM cost shift ranged between $1 billion and $3.4 billion per year as of 2020 to 2021.[181] Most of this cost burden is shifted to non-NEM customers, since much of NEM customers' bills are offset by the NEM systems.

NEM Cost Shift = NEM Customer Bill Savings – Utility Avoided Costs

Bill savings is the yearly dollar amount that NEM customer avoid paying because of their self-generation and netting (inflated export compensation rates). This includes generation cost savings for self-consumption and distribution and other fixed cost savings for exports. Avoided costs are costs such as infrastructure upgrades that the utility should avoid incurring as a result of distributed generation. Figures 14-16 show the estimated annual historical NEM cost shift for bundled residential customers calculated by each IOU.[182] The NEM 2.0 cost shift data is additive to the NEM 1.0 cost shift data. For example, for PG&E 2022 data, NEM 2.0 cost shift is about $700 million per year, which when added to NEM 1.0 cost shift data of about $300 million per year, results in a total cost shift of about $1 billion per year.

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[178] These benefits are measured in the form of deferring distribution system upgrades costs---avoided costs---which were determined in the NBT Decision to be Avoided Cost Calculator values.
[179] Other rates besides distribution rates may also be affected by the avoidance of fixed costs.
[180] Avoidance of other non-grid related fixed costs such as Public Purpose Program (PPP) or other non-bypassable charges (NBC) was addressed in the NEM 2.0 decision.
[181] One of these parties, the Public Advocates Office at the CPUC, in comments later estimated the cost shift at $4.6 billion as of 2022.
[182] Data is from data response submitted to Energy Division in March 2023.

Figure 14: PG&E Annual Historical NEM Cost Shift, Bundled Residential Customers (2016 – 2022, $ millions)

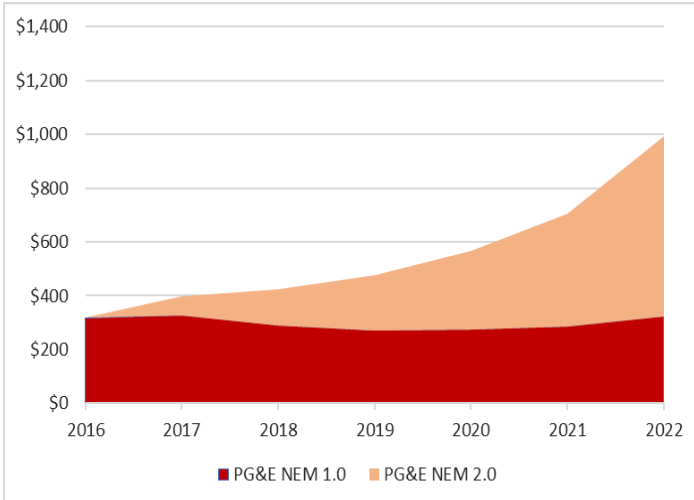


Figure 15: SCE Annual Historical NEM Cost Shift, Bundled Residential Customers (2016 – 2022, $ millions)

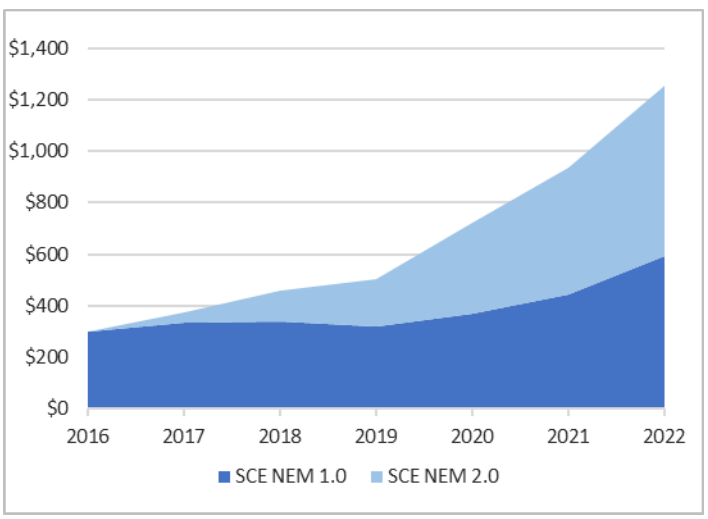
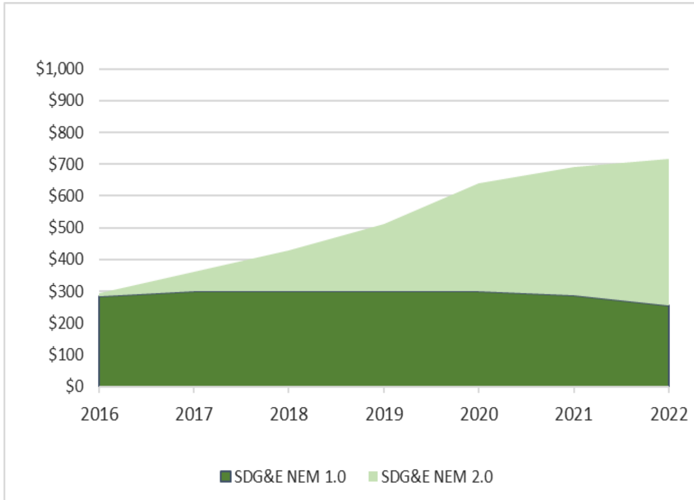


Figure 16: SDG&E Annual Historical NEM Cost Shift, Bundled Residential Customers (2016 – 2022, $ millions)



NEM Cost Shift Portion of Current Monthly Electric Bill

Table 14 shows the estimated portion of a typical bundled residential customer average monthly bill resulting from the 2022 NEM cost shift reflected in the above Figures 14-16, as calculated by each IOU.[183] Since the rate effect of the NEM cost shift cannot be directly determined, the estimated bill portion is shown as the difference between existing bills and what counterfactual bills would have been if there were no NEM cost shift. Most of this burden is shifted to the shrinking pool of NEM non-participants as much of NEM participants' bills are offset by the NEM systems. It is expected that when NBT implementation starts in 2023, the estimated NEM cost shifts shown in Table 14 will begin to reduce.[184]

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[183] Year-end 2022 rates in effect. 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.

[184] The CPUC adopted a five-year glide path as part of the successor tariff to minimize the cost shift, to ensure equity among all customers, and also to encourage the sustainable growth of the market, but not at the undue and burdensome financial expense of nonparticipant ratepayers.

Table 14: PG&E, SCE, and SDG&E 2022 NEM Cost Shift Portion of Year-End 2022 Average Monthly Bill, Bundled Residential Customers

Utility/ Residential Customer	Customer Monthly Bill with NEM Cost Shift	Customer Monthly Bill without NEM Cost Shift	Estimated NEM Cost Shift ($)	Estimated NEM Cost Shift (%)
PG&E Non-CARE	$167	$144	$23	13.8%
PG&E CARE	$107	$92	$15	14.0%
SCE Non-CARE	$153	$140	$13	8.5%
SCE CARE	$103	$95	$8	7.8%
SDG&E Non-CARE	$159	$132	$27	17.0%
SDG&E CARE	$103	$86	$17	16.5%

Recent Policy Actions to Address Affordability

The NBTs largely eliminate the NEM 1.0 and 2.0 overcompensation of exported energy portion of the cost shift by setting exported energy compensation equal to avoided cost, with a glide path transition incentive during the first five years.[185] The NBT Decision determined that the reformation of fixed charges for all residential customers who use the grid, as an opportunity to recover fixed costs and prevent cost shifts, should be addressed in the Rulemaking to Advance Demand Flexibility Through Electric Rates (Demand Flexibility Rulemaking).[186] The NBT Decision considered this new rulemaking to be a more appropriate venue to consider the issue of accurately calculating a customer's energy and grid usage while ensuring that the grid is prepared for the intermittent decrease and increase of usage.

Historical Trends in Electric Rates and Bills

Historical rate trends allow comparison of how an IOU's rates track another metric, inflation, over time. The reason inflation is typically used as a benchmark for electric rate growth is 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, it should be noted that while inflation generally affects the costs

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185 For the first five years of NBT, export compensation rates will be based on a nine-year schedule of values for each hour from the most recent Avoided Cost Calculator, adopted as of January 1 of the calendar year of the customer's interconnection date. Following the locked in period, retail export compensation rates will be based on averaged hourly avoided cost values from the most recent Avoided Cost Calculator, adopted as of January 1.

186 *See* R.22-07-005.

underlying the utility's revenue requirement, rates and bills are impacted by other factors, such as demand forecasts and commodity costs.

Bundled System Average Rate

Rates may be viewed at system level for all customer classes or at customer class level, such as residential class level. **Bundled system average rate (SAR)** is a high-level measure of an IOU's authorized bundled[187] customer revenue requirement expected to be recouped through authorized forecasted sales to bundled customers.

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

Bundled System Average Rate by Customer Class

A breakdown of the bundled system average rate by customer class is shown for each IOU in Figures 17-19.[188] Each class shows the same upward trend as the system average rate over this period, with residential and small commercial customers generally having higher average rates than the system average, and the large industrial and agricultural customers having lower average rates, with the exception of PG&E agricultural customers who have higher average rates than system starting in 2019.[189] Medium commercial customers generally have about the same rates as the system average, with the exception of SCE medium commercial customers who have higher average rates than system.

[187] Bundled IOU customers receive all services — generation, transmission, and distribution services — from the IOU.
[188] Includes California GHG Allowance Return which functions as a revenue requirement reduction.
[189] This effect for PG&E agricultural customers is driven mostly by the changes in the billing determinants that reflect changes in electric usage patterns for the Agricultural class.

Figure 17: PG&E Bundled System Average Rate By Class, Nominal Rates in Effect January 1[190] (¢/kWh)

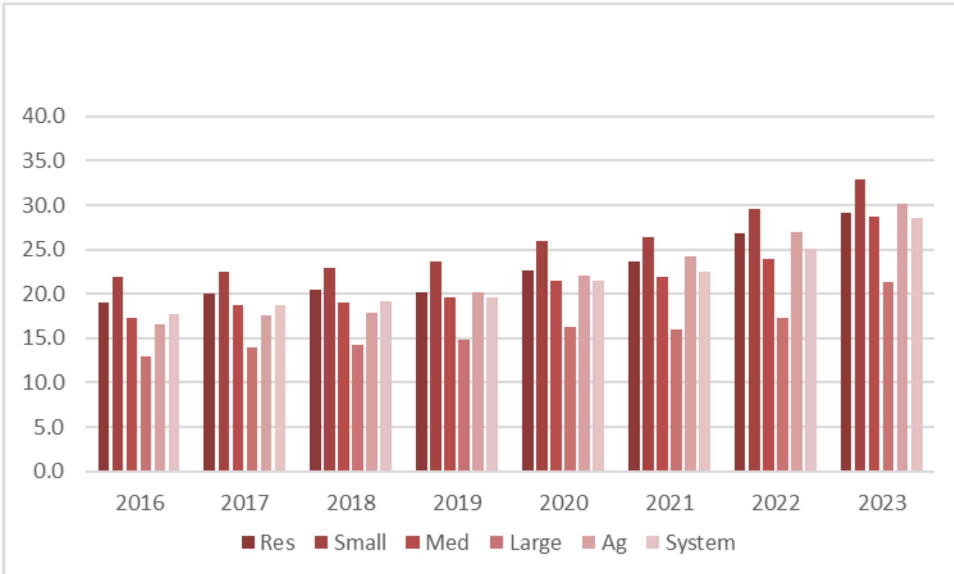
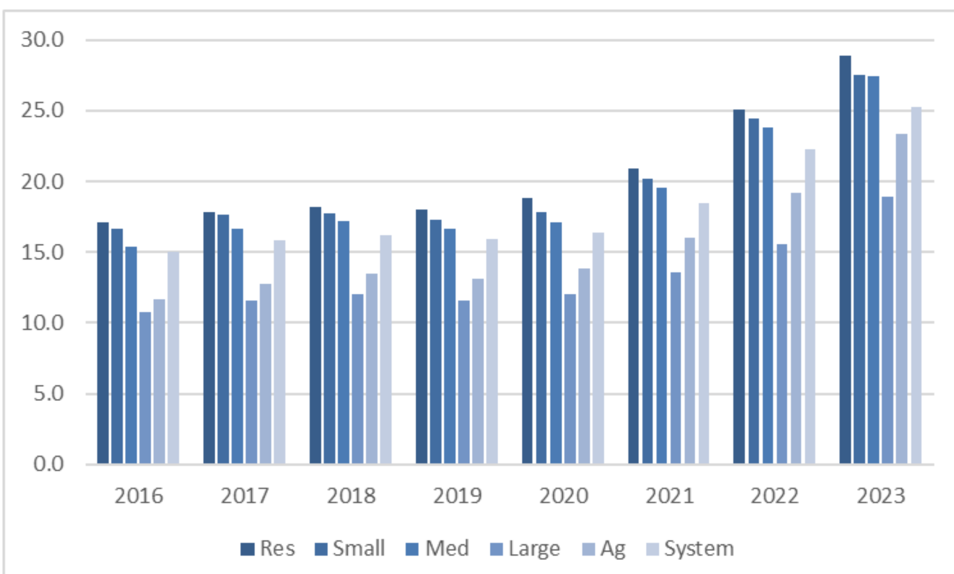


Figure 18: SCE Bundled System Average Rate By Class, Nominal Rates in Effect January 1[191] (¢/kWh)



[190] Customer class rate schedules: Res = E-1 & EL-1; Small = A-1; Medium = A-10 & E-19; Large = E-20; Ag = AG.

[191] Customer class rate schedules: Res = Domestic and D-CARE; Small = TOU-GS-1; Medium = TOU-GS-2 & TOU-GS-3; Large = TOU-8-S/P/T & TOU-8-S-S/P/T; Ag = TOU-PA-2 & TOU-PA-3.

Figure 19: SDG&E Bundled System Average Rate By Class, Nominal Rates in Effect January 1[192] (¢/kWh)

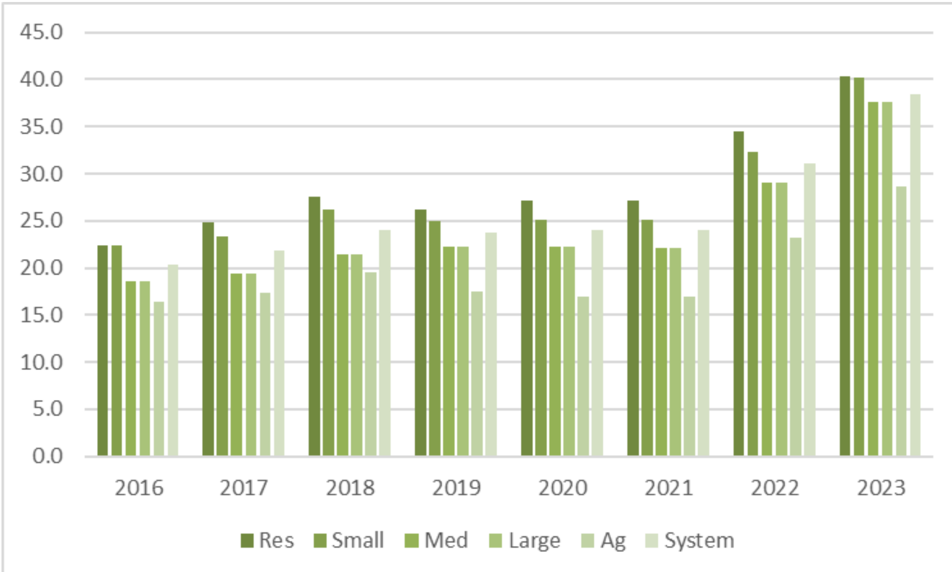


Figure 20 shows the simple volumetric bundled industrial sector average rate[193] based on U.S. Energy Information Administration (U.S. EIA) data.[194] While California industrial customers generally have lower average rates than the system average rate, California industrial average rates are higher than those in neighboring western states. A survey of western regional states shows that California IOU industrial rates have been about 140 percent higher than the non-California IOU regional average rate over the 2016 – 2021 period.[195] However, industrial customers that have set a business goal to use 100 percent renewable energy by 2045 may have more difficulty doing so in non-California western regional states.[196] Further, California industrial customers may enjoy

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[192] Class-level rates are not associated with any specific rate schedule. SDG&E has a combined medium/large commercial & industrial customer class.

[193] Simple volumetric rate is electricity price derived from dividing utility revenues from retail electricity sales by retail sales of electricity. Non-ratepayer funded sources, such as Greenhouse Gas Revenue Return credits from California's Cap-and-Trade program are not included.

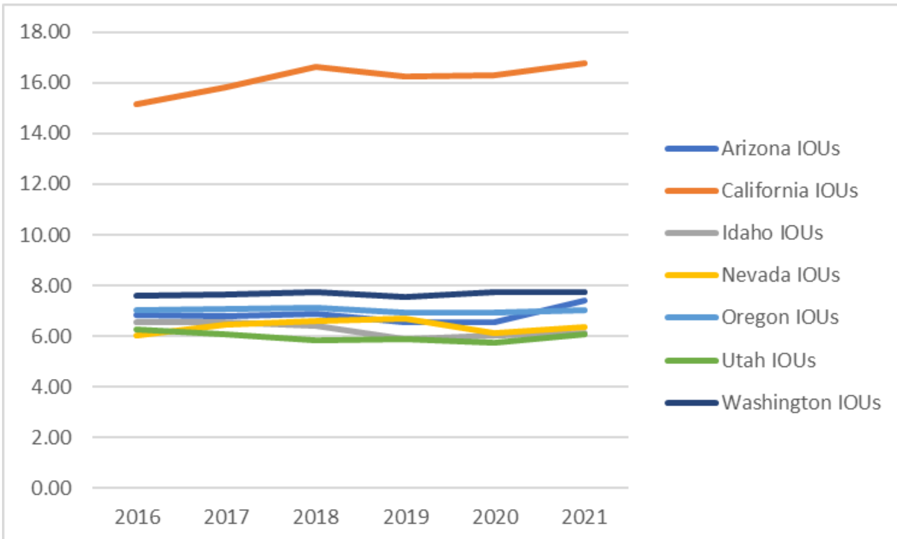
[194] *See* https://www.eia.gov/electricity/sales_revenue_price/, Table 8, all IOUs for each selected state. Table 8 Industrial sector data does not directly coincide with the customer classes shown in Figures 17-19. Regional states selected based on California Large Energy User Association's (CLECA) presentation of Industrial sector electricity rates at the California State Senate Energy, Utilities and Communications Committee Hearing (marker 2:01:37) archived at https://www.senate.ca.gov/media-archive. CLECA is an organization of large high load factor customers located in California. 2021 is the most recent year for which national-level data is available.

[195] CLECA contends in Affordability Proceeding comments that nonresidential customers are likely to relocate to neighboring western states if rates in California become untenable.

[196] SB 1020 (Laird, 2022) amended Section 454.53 of the Public Utilities Code to read: "It is the policy of the state that eligible renewable energy resources and zero-carbon resources supply 90 percent of all retail sales of electricity to California end-use customers by December 31, 2035, 95 percent of all retail sales of electricity to California end-use customers by December 31, 2040, 100 percent of all retail sales of electricity to California end-use customers by December 31, 2045…"

economies of scale and volume of sales due to population base density that may exceed that of neighboring states.

Figure 20: Select Western Region IOU Bundled Industrial Sector Average Rate (U.S. EIA, ¢/kWh)



Bundled Residential Average Rate

California's electric utility rates and bills are trending higher in national comparisons. Historically, the bundled[197] Residential Average Rates (RAR) of the California IOUs have been higher than those of most United States IOUs.[198] Despite the fact that average residential electricity usage in California is low compared to IOUs nationally, bundled residential average monthly bills have also been higher than those of most United States IOU customers since 2020.[199]

Table 15 shows the simple volumetric bundled RAR[200] for PG&E, SCE, and SDG&E from 2019 to 2021, based on U.S. Energy Information Administration (U.S. EIA) data.[201] This data ranks approximately 200 total IOUs nationally from highest rates (#1 ranking) to lowest rates (#200

[197] Bundled customers take generation, distribution, and transmission services from an IOU. Unbundled customers receive distribution and transmission services from an IOU but receive generation services from competing providers.
[198] *See* U.S. Energy Information Administration (U.S. EIA) data in Table 15. Rate data for all U.S. IOUs based on revenues divided by sales without regard to rate design.
[199] *Ibid.*
[200] Simple volumetric rate is electricity price derived from dividing utility revenues from retail electricity sales by retail sales of electricity. Non-ratepayer funded sources, such as Greenhouse Gas Revenue Return credits from California's Cap-and-Trade program are not included.
[201] *See* https://www.eia.gov/electricity/sales_revenue_price/, Table 6; 2021 is the most recent year for which national-level annual data is available.

ranking). For example, in 2021, SDG&E's bundled RAR ranked 6th highest. 2021 data in red font indicate a negative trend (i.e., higher rate or higher bill) over 2020 data.

While rates reflect the cost of providing each kilowatt hour of electricity, bill data provides a clearer picture of customer financial impact. From 2019 to 2021, California IOU bundled residential customer bills have been quickly trending upward relative to the bills of approximately 200 total IOUs nationally. For example, in 2019, PG&E's bundled residential average monthly bill ranked 70th highest out of about 200 IOUs, but in 2021, PG&E's bundled residential average monthly bill ranked 17th highest. SCE and SDG&E's bundled residential average monthly bills show similar bill ranking trends since 2019, as shown in Table 15.

Table 15: U.S. IOU Ranking of PG&E, SCE, and SDG&E (Out of Approximately 200 IOUs)
Bundled Residential Average Rates and Monthly Bills (U.S. EIA)

	Bundled Residential Average Rate (cents/kWh)			Bundled Residential Average Monthly Bill ($)		
	2019	**2020**	**2021**	**2019**	**2020**	**2021**
PG&E	24	13	**9**	70	25	**17**
SCE	42	21	**17**	142	85	**70**
SDG&E	17	9	**6**	122	87	88

Table 16 shows the corresponding U.S. EIA rate and monthly bill amounts for the large California IOUs.[202]

Table 16: PG&E, SCE, SDG&E Bundled Residential Average Rate and Monthly Bill (U.S. EIA)

	Bundled Residential Average Rate (cents/kWh)			Bundled Residential Average Monthly Bill		
	2019	**2020**	**2021**	**2019**	**2020**	**2021**
PG&E	22.4	23.7	25.9	$118	$139	$150
SCE	16.2	18.2	21.3	$93	$109	$121
SDG&E	25.8	25.5	30.7	$99	$107	$112

[202] Bill amounts are hypothetical at class level without distinction between customers who receive a low-income program bill discount and those who do not. U.S. EIA data for 2021 shows average monthly usage figures: PG&E 579 kWh; SCE 565 kWh; SDG&E 367 kWh.

Allocation of revenue requirements across customer classes determines the rates ultimately paid by individual customers. Bundled residential average rate (RAR) is determined in a similar manner as bundled SAR, except that instead of using system-level (i.e., all) bundled revenue requirement and bundled system-level forecasted sales, the revenue requirement is allocated to the bundled residential class and bundled residential class forecasted sales are used. Residential tariffs are then designed to collect the revenue requirement based on the forecasted sales reflected in the RAR.

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

RAR in Recent Years

Since 2013,[203] bundled residential average rates have increased at an average annual rate greater than the assumed rate of inflation: about 8 percent for PG&E, 7 percent for SCE, and 12 percent for SDG&E.[204]

Figures 21-23 show each IOU's nominal and inflation-adjusted bundled RAR for the period 2013 to 2023 and each IOU's bundled residential revenue requirement and forecasted sales for the period 2016 – 2023.[205] Side-by-side presentation facilitates comparing how RAR is impacted by changes in constituent revenue requirement and forecasted sales. For the graphs showing rates, nominal rates trending below the black line (i.e., inflation-adjusted rates) indicate that the IOU's bundled RARs are tracking favorably to inflation-adjusted rates. Nominal rates trending above the black line indicate that the IOUs' bundled RARs are increasing at a rate higher than the rate of inflation. In the graphs showing revenue requirement and forecasted sales, certain bundled residential data is considered confidential by SCE and SDG&E and has been labeled as such where applicable.

Figure 21 shows PG&E's nominal bundled RAR starting to generally increase at an increasing rate in the year 2020. From 2020 to 2023, bundled revenue requirement decreased on an average annual change basis about 1 percent and bundled residential authorized forecasted sales decreased on an average annual change basis about 8 percent. Over this time period, the average annual decrease in revenue requirement was not sufficient to compensate for the decrease in forecasted sales, resulting in an average annual increase to bundled RAR of about 10 percent.

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[203] Prior to 2013, the total system average rate (i.e., all rate classes) of each of the IOUs roughly tracked inflation; *See* the 2022 Assembly Bill (AB) 67 Report. Rate increases calculated from January 1, 2013 to January 1, 2023.

[204] Average annual inflation rate (2013 base year to 2023) is 3.4 percent, based on Consumer Price Index (CPI), California Region, All Items, All Urban Consumers, reported by the California Department of Finance (DOF), available here (CPI Forecast Data prepared in November 2022; 2022 & 2023 forecasted). Rate increases calculated from January 1, 2013 to January 1, 2023.

[205] 2016 is the most recent year for which data was requested. Includes the California Climate Credit (CCC) which functions as a revenue requirement reduction.

Figure 21: PG&E Nominal and Inflation-Adjusted Bundled Residential Average Rate and Bundled Residential Authorized Revenue Requirement and Forecasted Sales (January 1)

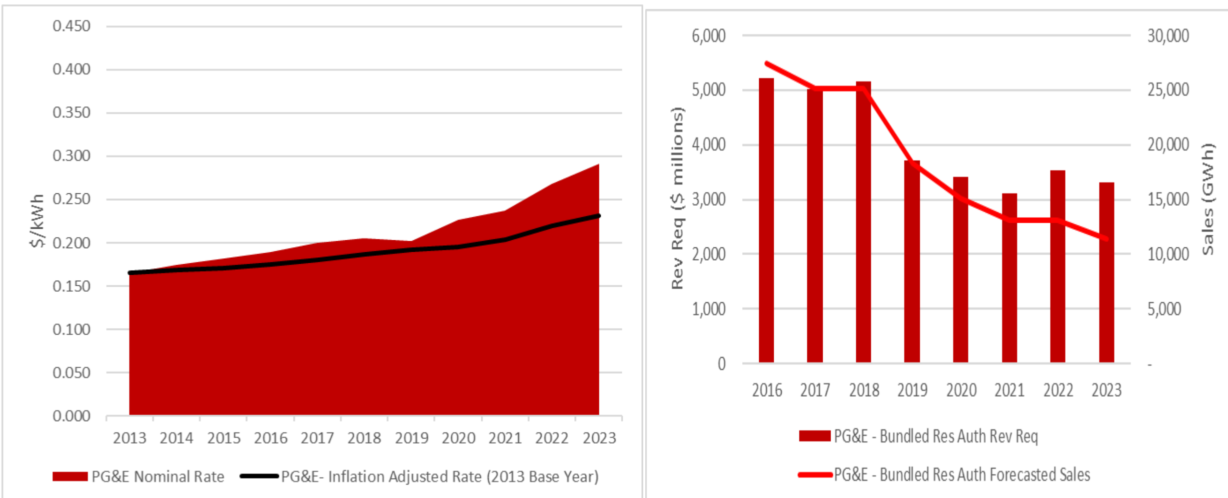
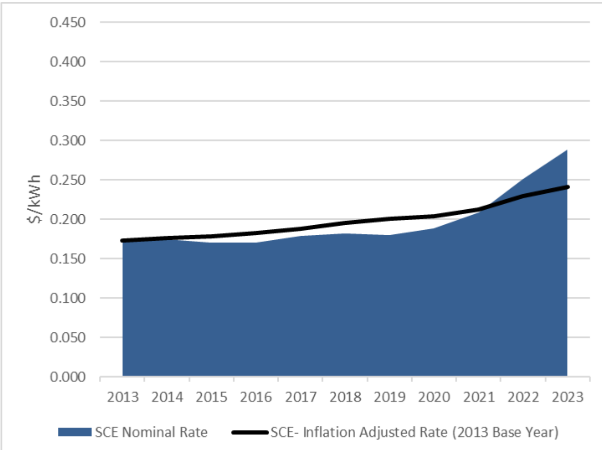


Figure 22 shows SCE's nominal bundled RAR starting to generally increase at an increasing rate in the year 2021 and how commendably well its bundled RAR appears to comport against inflation up until that time. From 2020 to 2021, bundled revenue requirement increased about 9 percent and bundled residential authorized forecasted sales decreased about 2 percent. Both of these countervailing effects result in an average annual increase to bundled RAR of about 11 percent over this time period. Data needed to further deconstruct bundled RAR beyond 2021 is not currently available due to confidentiality labeling.[206]

[206] SCE claims confidentiality for its bundled load forecasts in its ERRA Forecast proceedings for the forecast year and one previous year under D.06-06-066, Matrix section V.C. For more information about the confidentiality of certain SCE bundled customer information, *see* 2021 SB 695 Report, Chapter III, section "Bundled Rate Transparency Considerations."

Figure 22: SCE Nominal and Inflation-Adjusted Bundled Residential Average Rate and Bundled Residential Authorized Revenue Requirement and Forecasted Sales (January 1)



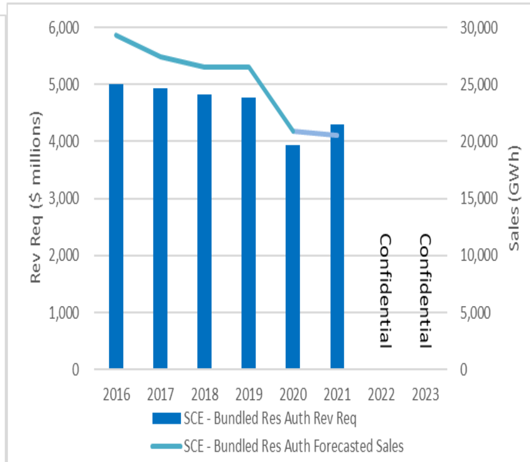
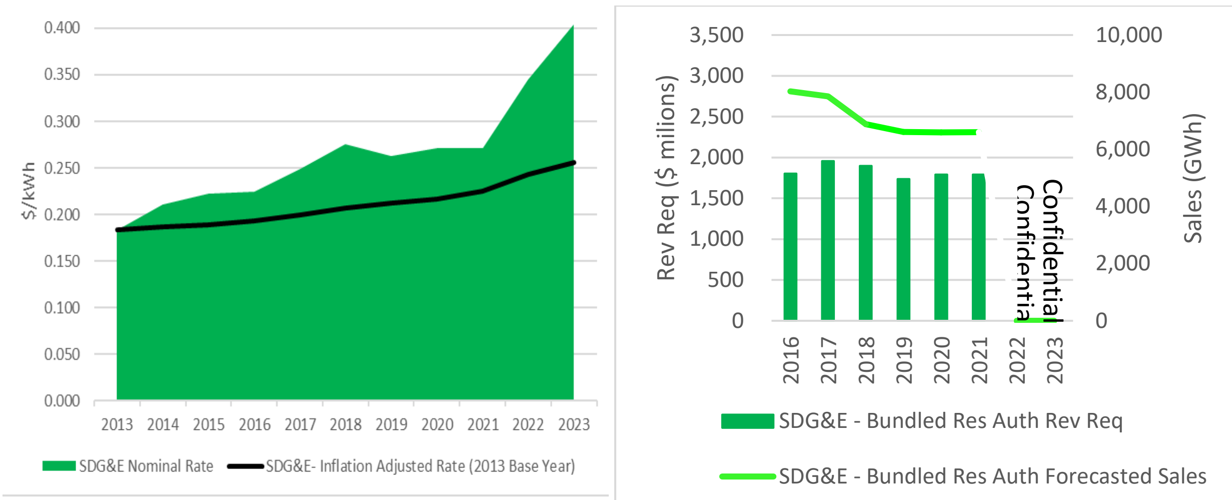


Figure 23 shows SDG&E's bundled RAR sharply increasing in the year 2022 as well as how its bundled RAR has historically not maintained a close correlation with inflation. The data needed to further deconstruct bundled RAR in 2022 and 2023 is not currently available due to confidentiality labeling.[207]

SDG&E has a larger share of customers investing in rooftop solar compared to PG&E and SCE. This high rate of photovoltaic (PV) adoption decreases the denominator (kWh sales) of SDG&E's bundled RAR, as customers are purchasing less electricity from the utility, although they may still be consuming the same amount from their PV system. While this decreased demand allows SDG&E to avoid some costs of procuring generation, a utility still has fixed costs that cannot be fully eliminated. These fixed costs include maintaining and building new grid infrastructure and paying for power plants and solar farms built or contracted by utilities in previous years. As a result, declining utility sales result in larger rate increases as utility fixed costs are now spread across fewer units of usage. SDG&E calculates that as a result of declining sales and other factors, under current NEM tariffs, Non-CARE and CARE customer bills for NEM non-participant customers are about 17 percent and 29 percent higher, respectively, than they would have been without current NEM tariffs.[208]

[207] SDG&E claims confidentiality under section V.C. of the IOU Confidentiality Matrix, adopted as Appendix 1 of CPUC Decision D.06-06-066. For more information about the confidentiality of certain SDG&E bundled customer information, *see* 2021 SB 695 Report, Chapter III, section "Bundled Rate Transparency Considerations."
[208] *See* previous section in this chapter "Net Energy Metering and Net Billing Tariffs Cost Shifts."

Figure 23: SDG&E Nominal and Inflation-Adjusted Bundled Residential Average Rate and Bundled Residential Authorized Revenue Requirement and Forecasted Sales (January 1)



Current Year-Over-Year RAR and Bills

The CPUC is tracking electric and natural gas utility costs and rates to keep the public and policymakers apprised of recent trends.[209] From January 1, 2022 to January 1, 2023,[210] electric bundled residential average rates have increased approximately 9 percent for PG&E, 15 percent for SCE and 17 percent for SDG&E, resulting in monthly bill increases as shown in Table 17.[211]

Table 17: Recent Increases in Bundled Residential Average Rates and Monthly Bills

	Residential Average Rates ($/kWh)			Average Residential Monthly Bills ($)		
	Jan-1-2022	Jan-1-2023	% Change	Jan-1-2022	Jan-1-2023	% Change
PG&E	0.268	0.291	8.6%	$148	$173	16.9%
SCE	0.251	0.289	15.1%	$139	$165	18.7%
SDG&E	0.345	0.404	17.1%	$159	$183	15.1%

On a weighted-average basis,[212] customers of the large electric IOUs paid about 18 percent more for electricity on January 1 of this year than January 1 of last year. These increases were largely driven by wildfire mitigation operating expenses, including vegetation management efforts and wildfire

[209] *See* CPUC Rate Change Advisories.
[210] Rates include the California Climate Credit (CCC).
[211] Bills for 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.
[212] Weighted by approximate residential customers: PG&E 45%, SCE 45%, and SDG&E 10%.

liability insurance, and major price increases for natural gas power plant fuel.[213] These increases may also reflect the NEM cost shift, discussed in a previous chapter, due to overcompensation of NEM participant exported energy and NEM participant avoidance of fixed costs.[214]

Bundled Residential and Select Small Commercial Average Monthly Bills

Anecdotally, IOU customers are more likely to recall their monthly bill amount rather than the rate at which their electricity is served, indicating that customers naturally think in terms of paying bills, not rates. A residential customer's total monthly bill is largely driven by the volume of their monthly usage, as reflected in the generation and delivery portions of their bill. However, even though average residential usage in California is low compared to that of the United States, low usage is showing diminishing returns as a mitigating factor and may no longer be enough to limit residential customer bill impacts due to rising rates.

The major determinant in calculating bills is electricity **usage**.[215] Residential usage tends to cluster around typical usage profiles, which vary by climate zone.[216] However, typical load profiles for non-residential customers can vary substantially, depending on their usage patterns (or load profiles) in the commercial, industrial, or agricultural customer class.[217] Nevertheless, small commercial customers may be grouped by commercial customer group using standards such as the North American Industry Classification System (NAICS) to get a sense of typical usage characteristics for customers with the same industry code.[218]

Figures 24-26 show for each IOU typical bundled average monthly bills for residential customers[219] as well as for small commercial customers representing Food Services and Drinking Places (NAICS 722), Ambulatory Health Care Services (NAICS 621), and Real Estate (Property Management, NAICS 531).[220] Bundled small commercial customers with industry subsector Food Services (NAICS 722) show typical average monthly bills in the $500 to $1000 range (and even higher in

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[213] *See* PG&E, SCE, and SDG&E Rate Change Advisories for the period January 2022 to January 2023.

[214] NEM cost shift effects may be directly attributable e.g. avoidance of grid access costs, or may be generally attributed to a decline in electric sales.

[215] Usage (in kWh) multiplied by a rate factor equals the volume of electricity billed. Other bill elements such as fixed charges and taxes are outside the scope of this analysis.

[216] Climate zones are drawn in each IOU's service territory based on climactic variation and are also known as baseline territories as defined by each IOU in its Preliminary Statements. For this analysis, residential average monthly usage for each IOU is based on average monthly usage reported for bill impacts presented in bill inserts.

[217] For non-residential, usage may include electricity consumption (kWh) or demand (kW). Demand usage is outside the scope of this analysis.

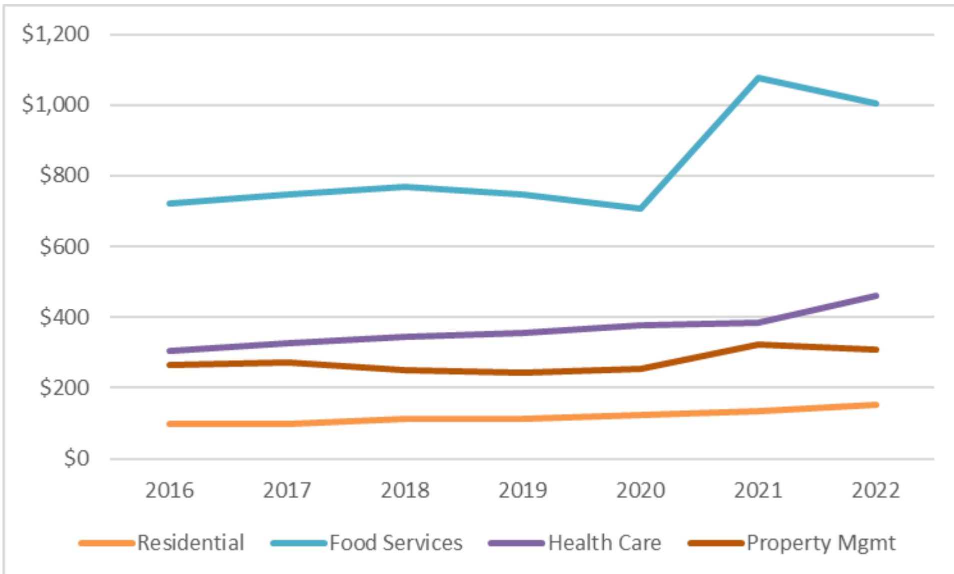
[218] Grouping by industry code does not definitively determine typical usage profiles as several other factors such as climate zone, size of establishment, age of establishment, and energy efficiency of equipment may significantly affect usage.

[219] 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.

[220] *See* U.S. Bureau of Labor Statistics for more information about NAICS subsector codes. These NAICS subsector codes were selected by the IOUs as being representative of small commercial customers and are not exhaustive for the customer class.

years 2021 and 2022 in some cases), with industry subsector Health Care Services (NAICS 621) and Property Management (NAICS 531) showing bills in the range of $200 to $400. Residential monthly bills are above $100.[221]

Figure 24: PG&E Typical Bundled Average Monthly Bills, Residential and Select Small Commercial, Nominal Rates in Effect January 1 ($/Month)



221 Typical average monthly bills are for illustrative purposes only.

Figure 25: SCE Typical Bundled Average Monthly Bills, Residential and Select Small Commercial, Nominal Rates in Effect January 1 ($/Month)

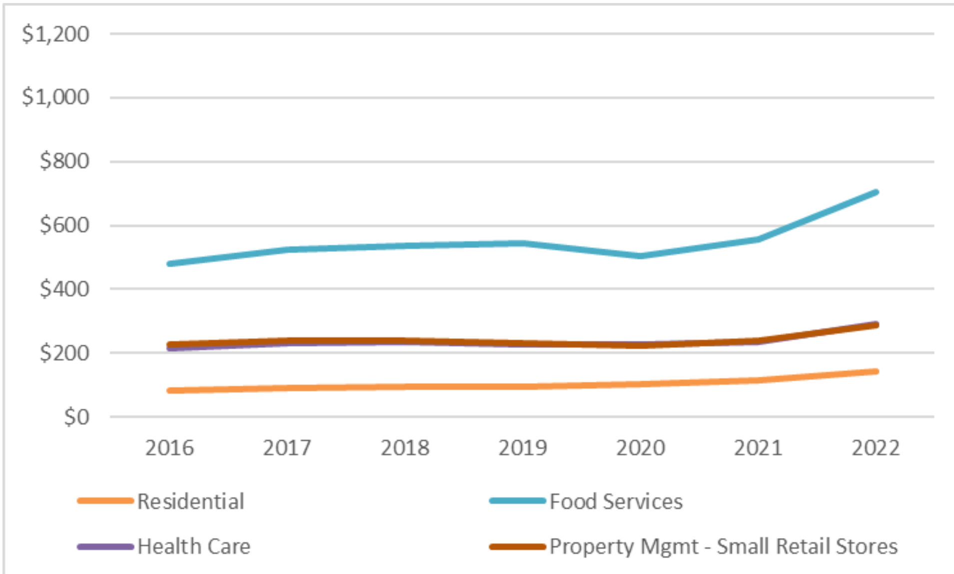
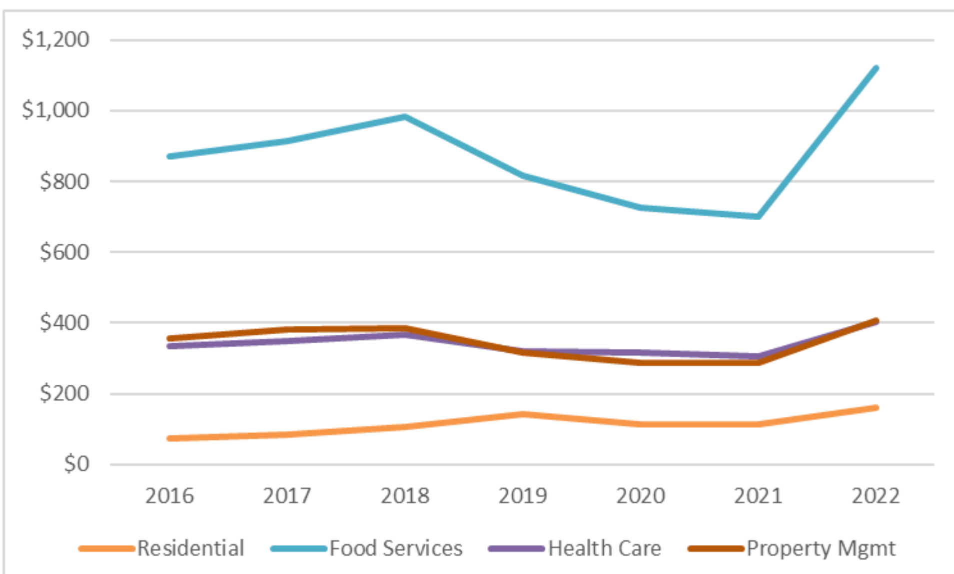


Figure 26: SDG&E Typical Bundled Average Monthly Bills, Residential and Select Small Commercial, Nominal Rates in Effect January 1 ($/Month)



IV. ELECTRIC IOU BUNDLED RESIDENTIAL CUSTOMER RATES FORECAST

Electric IOU rates are projected to continue to rise to cover investments in wildfire mitigation measures, clean energy resources and electric systems reliability enhancements. While these investments will yield substantial reductions in greenhouse gas emissions and criteria air pollution, significantly reduce the risk of wildfire ignition from electrical equipment, and bolster system reliability during extreme weather events, the anticipated increase in rates is not sustainable. In fact, if these costs are not prudently managed and alternative funding sources are not utilized, the state could undermine its progress toward its goal of delivering a safe, reliable, affordable, and clean energy electric system.

Forecasted Incremental Revenue Requirement and Projected Rate Impacts

As part of the Affordability proceeding,[222] the CPUC ordered PG&E, SCE, and SDG&E to each submit a quarterly cost and rate tracker (CRT) tool to Energy Division for evaluating the inputs of the affordability metrics developed as part of the rulemaking and for other ongoing support of the CPUC's work.[223] In addition to producing bundled residential essential usage bills[224] for the affordability metrics, each IOU's CRT may be used to produce a short- to medium-term bundled residential cumulative rate forecast[225] to show overall rate trends.[226] The CRT can also use the rates forecast to project estimated bills for bundled residential customers at IOU climate zone level.[227]

The CRT models cumulative forecasted revenue requirement[228] and forecasted sales[229] information as provided by the IOUs to produce rates.[230] Forecasted incremental revenue requirement information is updated in the CRT for the duration of each cost recovery proceeding, to reflect the

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222 *See* R.18-07-006.
223 *See* D.20-07-032, Ordering Paragraph (OP) 1.
224 Essential usage bills (EUB) reflect essential service, which is the minimum amount of service measured by the metrics. EUBs are used as an input to calculate certain affordability metrics.
225 The forecasts produce cumulative rate impacts, assuming recovery of all pending rate requests for the current year and three additional years.
226 Rates and bills for non-residential customer classes are not produced in the CRTs, as usage for a typical non-residential customer needed to show bill impact is difficult to define.
227 Climate zones are drawn in each IOU's service territory based on climactic variation and are also known as baseline territories as defined by each IOU in its Preliminary Statements.
228 Includes balancing account balances and the California Climate Credit (CCC). The CCC functions as a revenue requirement reduction.
229 Forecasted sales are based on authorized sales forecasts or on sales forecasts requested in pending applications, if available.
230 Energy Division staff may modify the forecasts to reflect estimates for cost recovery applications not yet filed and to take into account historical trends in revenue requirement and rates. Forecasts do not take into account future natural gas price spikes, which are difficult to predict. Forecasts also do not take into account future NBT cost shifts, except to the extent that they may be reflected in historical trends in revenue requirement and rates.

most-recent publicly-available revenue requirement.[231] The tool may still have limitations based on the completeness and classification of data provided by the utilities. For example, certain wildfire mitigation plan cost recovery applications have not yet been filed, and the IOUs may not have filed estimates of the cost recovery in the CRTs. Further, if a breakout in the CRT of certain types of costs is desired such as wildfire-related costs, it may be difficult to break them out from other costs included in a ratesetting application, such as the total revenue requirement requested in a GRC proceeding.[232]

Bundled Residential Average Rate Forecasts

Bundled residential average rate forecasts for the years 2023 – 2026 are shown in Table 18.[233] The forecasted rates are simple volumetric rates based on forecasted bundled residential revenue requirements and bundled residential forecasted sales. PG&E's, SCE's, and SDG&E's current electric CRTs[234] were used to produce the bundled residential average rates forecasts that are for illustrative purposes only and solely for use in this report. 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.

Table 18: PG&E, SCE, and SDG&E Forecasted Bundled Residential Average Rates (nominal $/kWh)

	Current	Year-End			
	Q1-2023	2023	2024	2025	2026
PG&E Nominal Rate	$ 0.305	$ 0.357	$ 0.366	$ 0.394	$ 0.424
SCE Nominal Rate	$ 0.288	$ 0.312	$ 0.310	$ 0.331	$ 0.353
SDG&E Nominal Rate	$ 0.404	$ 0.404	$ 0.447	$ 0.501	$ 0.562

231 Examples of changes to revenue requirement include revised testimony and settlement agreements.

232 Similar potential cost grouping difficulty may exist with transportation electrification costs as well, as programmatic capital costs are rolled into GRCs after program termination.

233 Cumulative rates, assuming recovery of all pending rate requests, are projected through year-end. Actual rates in effect at end of first quarter of 2023 (with estimated climate credit effect), with 3.75 years remaining through year-end 2026.

234 Current CRTs are for first quarter 2023 (Q1-2023) with current rates effective March 1, 2023 for PG&E and SCE, and January 1, 2023 for SDG&E. PG&E and SDG&E CRT sales forecasts held at currently authorized sales forecasts; SCE CRT sales forecasts are estimated 2023-2026 sales forecasts.

The average annual percentage change in forecasted 2026 bundled residential rates over 2023 current rates for each IOU are greater than the assumed average annual rate of inflation of 3.3 percent:[235]

- PG&E: about 39 percent through 2026 for an average annual increase of 10.4 percent
- SCE: about 23 percent through 2026 for an average annual increase of 6.0 percent
- SDG&E: about 39 percent through 2026 for an average annual increase of 10.4 percent

Table 19 shows the projected monthly bill increase resulting from the rates forecasts in Table 18 based on the usage amounts the IOUs use in their legal bill inserts[236] – 500 kWh per month for PG&E and SCE, and 400 kWh per month for SDG&E.[237] Average electricity bills for PG&E bundled residential customers are forecast to rise at an average annual change of about 11 percent, about 5 percent for SCE customers, and about 10 percent for SDG&E between now and 2026, implying that these households' energy bills will become less affordable if household incomes track the assumed inflation rate of 3.3 percent.

Table 19: Current and Projected Residential Average Monthly Bills (First Quarter 2023 – Year-End 2026)

IOU	Current (Q1-2023) Residential Average Monthly Bill	Projected Year-End 2026 Residential Average Monthly Bill	Projected 2026 Average Annual Percent Change
PG&E	$181	$255	10.9%
SCE	$164	$192	4.6%
SDG&E	$183	$250	9.8%

[235] Average annual inflation rate (2023 base year to 2026) is 3.3 percent, based on Consumer Price Index (CPI), California Region, All Items, All Urban Consumers, reported by the California Department of Finance (DOF), available here (CPI Forecast Data prepared in November 2022; 2022 & 2023 forecasted).

[236] 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."

[237] Bills for 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. Monthly usage data is that used in legal bill inserts for PG&E's 2023 General Rate Case (GRC) Phase I, SCE's 2021 GRC Phase I Track 4, and SDG&E's 2024 GRC Phase I. Bills calculated based on PG&E climate zone X, SCE climate zone 9, and SDG&E Inland climate zone. Bills are for illustrative purposes only.

Table 20 shows a comparison of 2023 and 2026 bills based on Non-CARE and CARE customer recorded average usage in 2022[238] for climate zones designated "moderate"[239] and "hot."[240] The IOUs do not currently use recorded average usage to calculate typical customer bills in their legal bill inserts (PG&E and SCE use 500 kWh/month and SDG&E uses 400 kWh/month),[241] nor do they use hot climate zones for these calculations (PG&E and SCE use a moderate climate zone, and SDG&E uses a hybrid of moderate and cool climate zones). Table 20 also shows this same comparison of 2023 and 2026 bills using typical customer bills.

Table 20: Comparison of Recorded Average Usage Monthly Bills in Moderate and Hot Climate Zones with Typical Average Usage Monthly Bills (First Quarter 2023 – Year-End 2026)

Residential Customer	2023 Moderate Recorded Usage	2023 Moderate Typical Usage	2023 Hot Recorded Usage	2023 Hot Typical Usage	2026 Moderate Recorded Usage	2026 Moderate Typical Usage	2026 Hot Recorded Usage	2026 Hot Typical Usage
PG&E Non-CARE	$158	$181	$205	$174	$222	$255	$288	$245
PG&E CARE	$90	$116	$146	$111	$128	$163	$205	$157
SCE Non-CARE	$205	$164	$274	$169	$239	$192	$319	$197
SCE CARE	$119	$111	$179	$114	$139	$130	$209	$133
SDG&E Non-CARE	$164	$183	$152	$182	$224	$250	$207	$247
SDG&E CARE	$125	$119	**$175**	$118	$171	$162	**$238**	$161

For moderate climate zones, PG&E and SDG&E recorded usage bills are generally lower than typical usage bills as the recorded usage for climate zone X and the Inland climate zone, respectively, is lower than the typical usage of 500 kWh/month and 400 kWh/month. However, SDG&E CARE customer bills show the opposite effect, with recorded usage for the Inland climate zone higher than the typical usage of 400 kWh/month. SCE customer bills also exhibits this effect, with the recorded usage for climate zone 9 higher than the typical usage of 500 kWh/month.

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238 The CRTs use recorded usage for the previous calendar year, and bill impacts presented in GRC applications and testimony use this convention as well.

239 "Moderate" climate zones are also sometimes referred to as "warm" climate zones, as opposed to "cool" or "hot." Moderate climate zones shown: PG&E X; SCE 9; SDG&E Inland.

240 Hot climate zones as defined in D.17-09-036, Decision Adopting Findings Required Pursuant to Public Utilities Code § 745 for Implementing Residential Time-of-Use Rates. Hot climate zones shown: PG&E R; SCE 15; SDG&E Desert. PG&E climate zone R

For hot climate zones, in all cases except for SDG&E Non-CARE, recorded usage bills are higher than typical usage bills, as expected, due to additional weather-related usage. SDG&E Non-CARE customer recorded usage is lower than typical usage due to low usage in the winter, which produces a lower annualized bill. Further, SDG&E CARE customer recorded bills, bolded in Table 20, are *higher* than comparative Non-CARE customer bills (figure immediately above the bolded figure). This indicates that CARE customers in hot climate zones may have higher usage than Non-CARE customers due to poor or outdated insulation in their homes, or are customers who cannot install distributed generation resources.

While climate zone selection and "typical" average usage data (PG&E and SCE use 500 kWh/month and SDG&E uses 400 kWh/month) used to produce bills for legal bill inserts is not set, additional consideration should be given to requiring the IOUs to present similar bills for hot climate zones based on recorded usage in legal bill inserts.

Electric Bill Affordability

Affordability of utility services cannot be measured based on the magnitude of utility bills alone. Electricity and natural gas are essential services, and consumers necessarily must purchase them to maintain a healthy living standard and meaningfully participate in society. Unlike other products or services, which customers are able to forego if prices rise too high, essential utility services will generally continue to be consumed regardless of price. This means that for low-income households, increases in utility bills will largely crowd out other purchases rather than affect energy usage behavior. Instead of observing actual consumption behavior or simply comparing changes in utility bills to inflation, it is necessary to develop metrics that consider the costs of essential services in relation to the socioeconomic conditions of the households that are paying for those services.

This section presents the current outlook for electricity affordability in California as measured by the affordability ratio (AR) metric that was adopted in Rulemaking (R.)18-07-006.[242] Using the most recently available data, this analysis presents affordability results for an essential level[243] of electricity service for the forecast years 2023 through 2026.

The CPUC has developed effective tools for measuring current and future affordability by geographic location. One key metric is the AR which quantifies the percent of a representative household's income used to pay for an essential utility service after non-discretionary expenses, such as housing and other essential utility services, are removed from the household's income. The

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 Desert climate zone includes Imperial County and other areas in the Imperial Valley.

241 U.S. EIA data for 2021 (latest calendar year available) shows average monthly usage figures: PG&E 579 kWh; SCE 565 kWh; SDG&E 367 kWh.

242 *See* D.20-07-032.

243 D.20-07-032 adopts climate zone-specific baseline allowance quantities for the definition of essential electricity service.

higher an AR, the less affordable the utility service. AR can be calculated for any of the four essential services individually (electricity, natural gas, water, and communications), or for the combined bundle of essential services. AR may also be calculated for any income level in a given area, with AR_{20} (the AR for a household at the 20th percentile income level) and AR_{50} (the AR for a household at the median, or 50th percentile, of income) chosen by staff as the standard representations.[244]

This section will focus exclusively on the AR_{20} results for electricity service, since this measure succinctly highlights where electricity affordability concerns are most significant and the degree to which affordability challenges are expected to become more severe over the forecast period. It is worth noting that the results presented here do not account for the impact of low-income programs such as CARE and FERA. This analysis characterizes the affordability of electricity service for low-income customers who do not necessarily qualify for assistance.

The AR calculation uses income and housing cost data that is estimated for geographic areas known as Public Use Microdata Areas (PUMA).[245] The distribution of incomes is particular to each PUMA and is measured in the Census Bureau's American Community Survey (ACS). The AR metric is sensitive to geographic variations in cost-of-living, which can impact the amount of income available to pay for essential utility services. Future values of income and housing costs for representative households are estimated by using the California Department of Finance's Economic Research Unit's regional forecasts of inflation and shelter cost growth to adjust historical income and housing cost estimates, respectively.[246]

Using the CRT-derived electric rate forecasts presented earlier in this report and the essential quantities of electricity consumption in each baseline territory, essential usage bills (EUB) were calculated for each IOU climate zone. EUBs for water, natural gas, and communications services, are based on historical EUBs for these services that have been adjusted using the Department of Finance regional inflation estimates.

In this analysis, PUMA boundaries have been overlaid with the service territory boundaries for the four essential services so that AR values can be calculated for representative households at very granular geographic levels. These granular AR values are then aggregated to the level of IOU climate zones through a weighted averaging process.[247] The resulting climate zone-level AR_{20} values are presented for the forecast period for each IOU.

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[244] The 20th percentile was selected because it represents households that are low-income but may not necessarily qualify for an assistance program such as California Alternate Rates for Energy (CARE).

[245] PUMAs are "non-overlapping, statistical geographic areas that partition each state or equivalent entity into geographic areas containing no fewer than 100,000 people each." There are currently 265 PUMAs in the state of California. By looking at a common income percentile across the different PUMAs in California, the AR metric characterizes the relative wealth of each PUMA to the others. More information on PUMAs can be found on the Census Bureau's website: https://www.census.gov/programs-surveys/geography/guidance/geo-areas/pumas.html

[246] For more details on the forecasting methodology, *see* D.22-08-023.

[247] For more details on the weighted average aggregation process, *see* D.20-07-032.

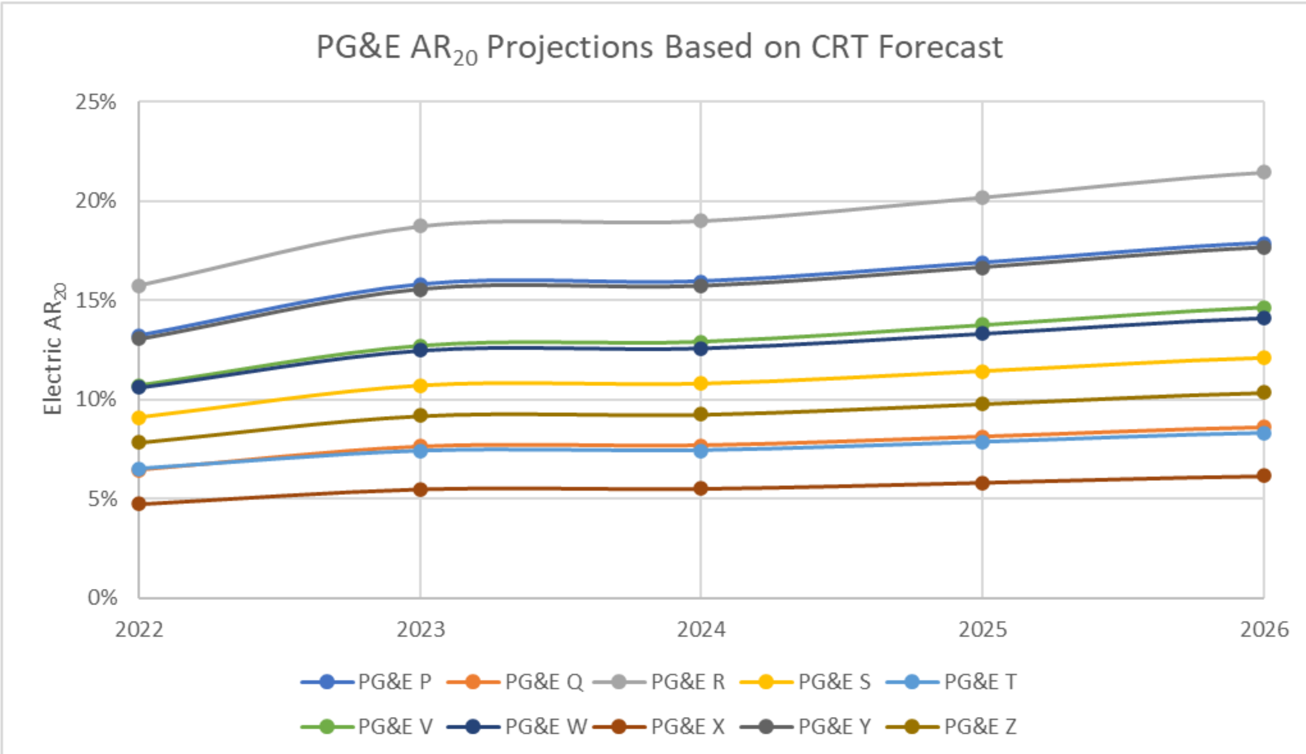
Table 21 shows the expected increase in weighted average electric AR20 values for PG&E climate zone R (a hotter region that includes Merced and Fresno), SCE climate zone 15 (along the California border with Nevada and Arizona and one of the hottest and least affordable regions in the state), and SDG&E's Mountain climate zone (one of its two warmest zones).

Table 21: Projected 2022 – 2026 Electric AR_{20}
Select Climate Zones

IOU and Climate Zone	Baseline 2022 Average AR_{20} (%)	Projected 2026 Average AR_{20} (%)	Projected Relative Percent Change
PG&E – R	15.7	21.4	36.3%
SCE – 15	17.6	23.4	33.0%
SDG&E – Mountain	11.0	15.6	41.8%

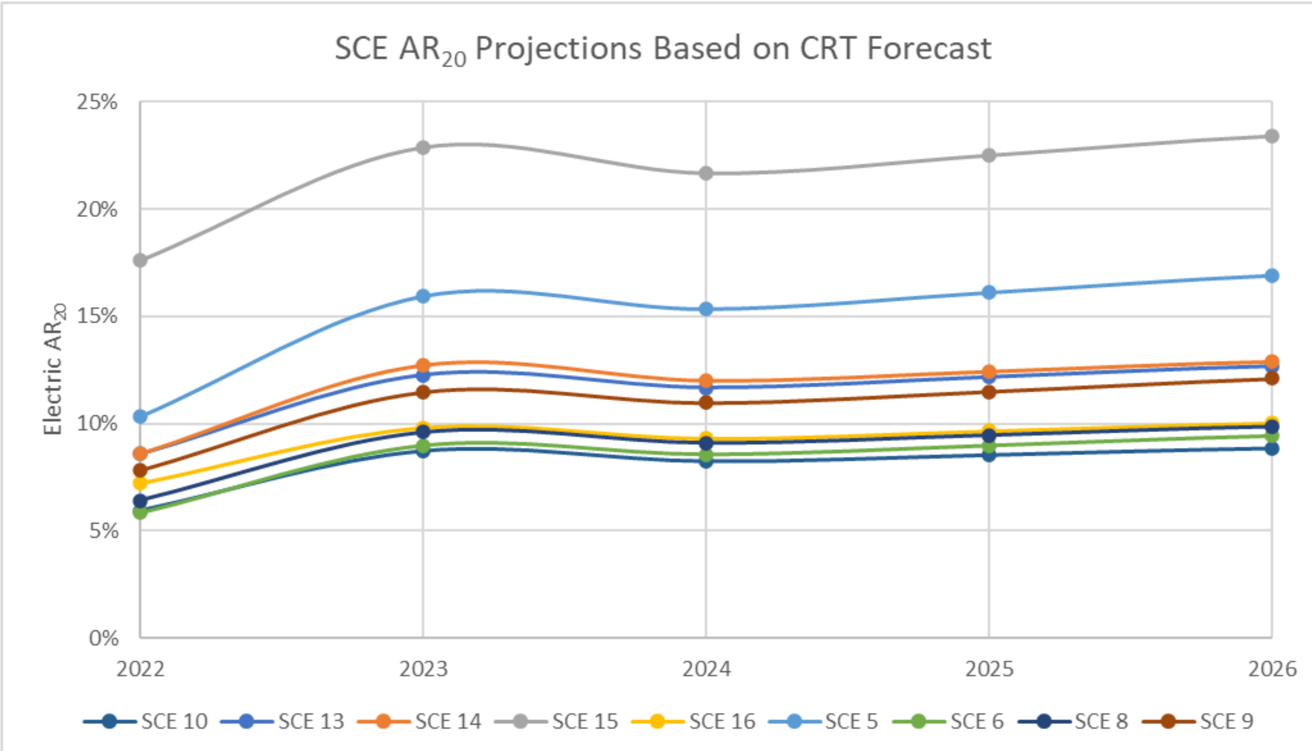
PG&E's AR_{20} forecast in Figure 27 shows that affordability of electric service is expected to worsen during the forecast period of 2023 – 2026 relative to the 2022 baseline. This indicates that the current outlook for rate increases will lead to EUB growth that will outpace the expected growth in household incomes. Much of that increase is expected to happen in 2023 when the AR_{20} value will increase 3 percentage points from 15.7 percent to 18.7 percent. While PG&E climate zone R is expected to have the worst AR values, the other PG&E climate zones are also expected to have increases in AR_{20} during the forecast period due to the large, forecasted increases in PG&E's electric rates. Across PG&E's climate zones, AR_{20} values are expected to increase between 27 percent and 37 percent by 2026 compared to the 2022 baseline. This implies that households' electric bills will become less affordable if household incomes track the inflation rate predicted by the Department of Finance.

Figure 27: PG&E Electric AR20 Forecast Based on CRT Projections by Climate Zone



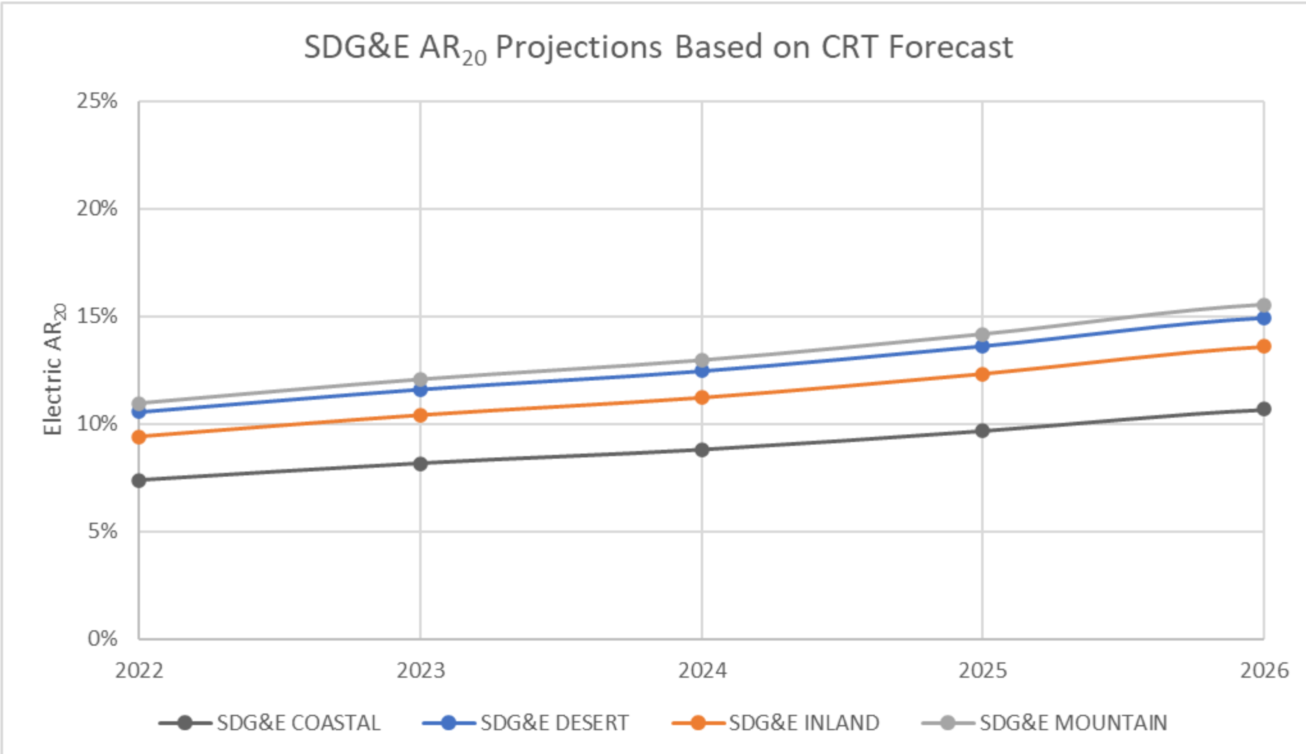
The SCE AR_{20} forecast presented in 8 shows a large uptick in AR_{20} in 2023 relative to the 2022 baseline. SCE's residential rates are currently forecasted to decrease slightly in 2024 before resuming a steady increase during the remainder of the forecast period. Since SCE's rates are expected to drop slightly in 2024, affordability is expected to improve a bit as income growth provides some relief before AR_{20} values resume their steady upward march. Across all of SCE's climate zones, AR_{20} values are expected to increase between 33 percent and 64 percent over the forecast period compared to the 2022 baseline.

Figure 28: SCE Electric AR20 Forecast Based on CRT Projections by Climate Zone



The SDG&E AR_{20} forecast is presented in Figure 29, and shows a steady increase in AR_{20} values over the forecast period. Across the four climate zones, AR_{20} values are expected to increase by between 41 percent and 45 percent by 2026 compared to the 2022 baseline. Even though SDG&E's volumetric rates are much higher than the rates of the other two IOUs, the more temperate weather (and thus, lower AC-driven electricity usage) and more affluent service territory have kept their EUBs more affordable, as measured by the AR_{20} metric. However, with an expected rapid growth in rates and bills over the forecast period, SDG&E customers will see a decline in electricity affordability over the next few years. As with the other IOUs, this implies that these households' electric bills will become less affordable if household incomes track the predicted inflation rate.

Figure 29: SDG&E Electric AR20 Forecast Based on CRT Projections by Climate Zone



V. Natural Gas Cost and Rate Trends

Background

The CPUC regulates the natural gas utility services of more than 10 million customer accounts served by Pacific Gas & Electric (PG&E), Southern California Gas Company (SoCalGas), San Diego Gas & Electric (SDG&E), and several smaller utilities.[248] Critical elements of the Public Utilities Code related to gas services require that the CPUC:

1. Evaluate the reasonableness of natural gas rates and rate changes;
2. Oversee Core Transport Agent (CTA) rules[249] and consumer protection matters;
3. Oversee the adoption of standards and incentives for biomethane production;
4. Oversee the implementation of utilities' Pipeline Safety Enhancement Plans (PSEP) to pressure test or replace all intrastate transmission pipelines that do not have a record of a pressure test;[250]
5. Determine the feasibility of minimizing or eliminating use of SoCalGas's Aliso Canyon gas storage facility while still preserving energy reliability;[251] and
6. Create a path to transition away from fossil gas while maintaining safety, reliability, and just and reasonable rates.

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

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

Natural gas utility costs may be categorized into the three main components: 1) core procurement costs, 2) costs of operating the natural gas transportation system and providing customer service,

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[248] Public Utilities Code Section 913.1(b) mandates that gas corporations with 500,000 or more retail customers in California study and report on measures the corporation recommends be undertaken to limit costs and rate increases. The large natural gas IOUs that are required by Public Utilities Code Section 913.1(b) to submit Senate Bill (SB) 695 reports are PG&E, SoCalGas, and SDG&E.

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

[250] Public Utilities Code Section 958: https://codes.findlaw.com/ca/public-utilities-code/puc-sect-958.html.

[251] Public Utilities Code Section 714: https://codes.findlaw.com/ca/public-utilities-code/puc-sect-714.html.

and 3) costs associated with gas public purpose programs (PPP). Core gas procurement commodity costs are passed directly on to gas customers with no markup and are recovered in utility gas procurement rates, which are adjusted monthly.[252] The other two components of natural gas utility costs are typically addressed in GRC and other cost recovery proceedings. These rate setting proceedings have several objectives, among them: setting rates as low as possible while yielding revenues that cover the utilities' costs; maintaining safe and reliable service; and promoting energy conservation and greenhouse gas (GHG) reduction.

The GRC establishes the total annual revenue required for a utility to recover its costs of serving customers and a fair return or profit on its investments for shareholders. The revenue authorized in a utility's GRC (called "revenue requirement") includes day-to-day operating costs of running the utility system, administrative and general expenses, depreciation of capital investments in facilities and assets over their useful lives, taxes, and a rate of return on invested capital. Utilities recover expenses (e.g., repairs, maintenance, inspections, etc.), on a dollar-for-dollar basis. They recover capital expenditures (e.g., plant, equipment, tools, etc.) through depreciation plus a rate of return on these investments.

Bundled gas rates are impacted by the following: 1) changes to revenue requirement, which are mostly determined in GRCs, 2) changes to forecasted sales demand, which are determined in cost allocation proceedings, and 3) core procurement costs adjusted monthly through advice letters filed by the IOUs. The rates paid by individual customers are also impacted by how the revenue requirement is allocated among customer classes in the cost allocation proceedings.[253] Gas revenue requirement and rates can also be affected by non-GRC proceedings.

The decisions of other state and federal agencies can also impact rates. The California Geologic Energy Management Division's (CalGEM's) 2018 changes to gas storage regulations increased the cost of maintaining gas storage facilities, and regulations enacted by the federal Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) in 2019 will increase the cost of operating and maintaining transmission pipelines. Rates also include the cost of a percentage of the GHG emissions resulting from gas consumption, per the California Greenhouse Gas Cap and Trade Program implemented by the California Air Resources Board. Of the Cap-and-Trade revenues collected in gas rates, most are returned to customers as climate credits and the remainder support building decarbonization programs.

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[252] The utilities' gas procurement hedging program can offset some of the commodity cost. The CPUC requires the utilities to purchase physical hedges in the form of long-term interstate pipeline capacity contracts and storage. The utilities also purchase financial hedges, which cover a portion of expected winter gas demand. If prices settle above a pre-determined level, the company receives a payment which is then used to lower customers rates and bills.

[253] The large utilities recover some of its 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.

Changes to Utilities' Revenue Requirements

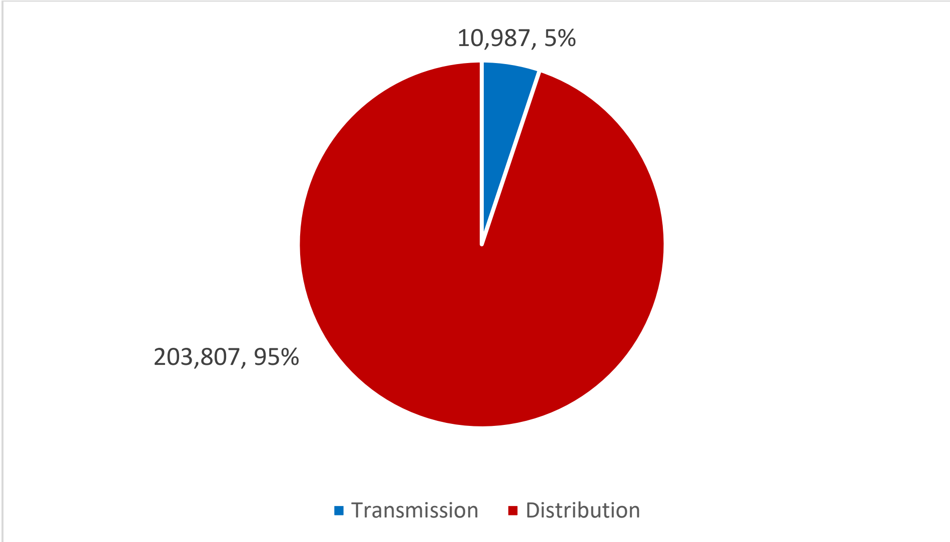
Overview

The sections below examine the changes to each utility's revenue requirement between 2016 and 2023.[254] They are broken down to show changes for different components of the utilities' gas delivery systems as well as commodity and PPP costs. Broadly speaking, the gas system includes backbone transmission, local transmission, distribution, and storage. The utilities' backbone transmission system consists of large diameter, high pressure pipelines that connect to the interstate pipeline system, bringing gas from receipt points at the California border to the local transmission and distribution system. Local transmission pipelines transport gas from the backbone system and storage fields to the distribution system. Distribution pipelines are smaller diameter, lower pressure pipelines that bring gas from the local transmission system to customers.

Transmission pipelines are more expensive to build and operate, but there are far more miles of distribution pipelines. In 2021, there were 10,987 miles of intrastate transmission pipeline and 203,807 miles of distribution pipelines in California.[255] Large noncore customers often take gas directly from transmission pipelines.[256] For example, PG&E indicates in A.21-09-018 that about 600 very large volume noncore customers, which account for about 93 percent of noncore throughput, receive their gas directly from the backbone or local transmission systems. In accordance with the regulatory principle of cost causation in which the beneficiary pays, such customers are not allocated costs for the distribution system. Thus, distribution costs are borne primarily by core customers.

[254] The source of these data is the utilities' February 21, 2023 response to the Energy Division's data requests. The core procurement revenue is based on an annual estimate; all other revenues are based on authorized revenue requirements. For all IOUs, the core procurement revenue requirement estimate is higher in 2022 than in 2021.
[255] PHMSA Miles and Facilities 2010+, California: Oracle BI Interactive Dashboards - Public Reports (dot.gov).
[256] Noncore customers consume about 65 percent of the natural gas delivered by California's natural gas utilities.

Figure 30: Miles of Transmission vs. Distribution Pipeline in California (2021)



Source: PHMSA

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

In the sections below, recent revenue requirement trends for the following categories are included for each utility: commodity[257], backbone transmission, local transmission, distribution, storage, and PPP and other. Commodity revenues cover the costs incurred by the utilities on procurement activities undertaken on behalf of core gas customers and includes gas commodity costs, net hedging costs, and brokerage fees. Backbone transmission revenues include capital, operations and maintenance (O&M), and administrative and general (A&G) costs recovered for backbone transmission pipelines, including the federally mandated Transmission Integrity Management Program (TIMP)[258] and state-mandated PSEP costs. Local transmission revenues include capital, O&M, and A&G costs recovered for local transmission pipelines, including TIMP and PSEP costs.[259] Distribution revenues include costs related to service lines, regulators, meters, meter

[257] The commodity revenue consists of annualized net commodity costs.
[258] TIMP requires operators to create and implement a plan to continually evaluate threats to their transmission pipelines, rank those threats, and take appropriate action to mitigate them as outlined in the Code of Federal Regulations (CFR) Title 49, Subpart O, §192. The plan must identify High Consequence Areas and use assessment methods such as inline inspection, hydrostatic testing, or direct assessment to monitor the integrity of pipelines in those areas. New PHMSA regulations added TIMP assessment requirements for a newly created category: Moderate Consequence Areas.
[259] Local transmission pipelines transport gas from backbone pipelines and storage fields to the distribution system.

reading and billing as well as the costs for maintaining and operating high and medium pressure distribution pipelines, which include the cost associated with the Distribution Integrity Management Program (DIMP).[260] Storage costs include the capital and O&M costs of operating natural gas storage facilities, including biennial well testing in accordance with CalGEM regulations and other aspects of the utilities' Storage Integrity Management Program (SIMP).[261] PPP and "Other" costs include the costs for the California Alternate Rates for Energy (CARE) program, energy efficiency (EE) and low-income EE, and the gas public interest research and development program, which is administered by the California Energy Commission (CEC). Because all three large IOUs saw significant cost increases in the commodity category, a special section on that topic is included below.

PG&E Revenue Requirement by Rate Category

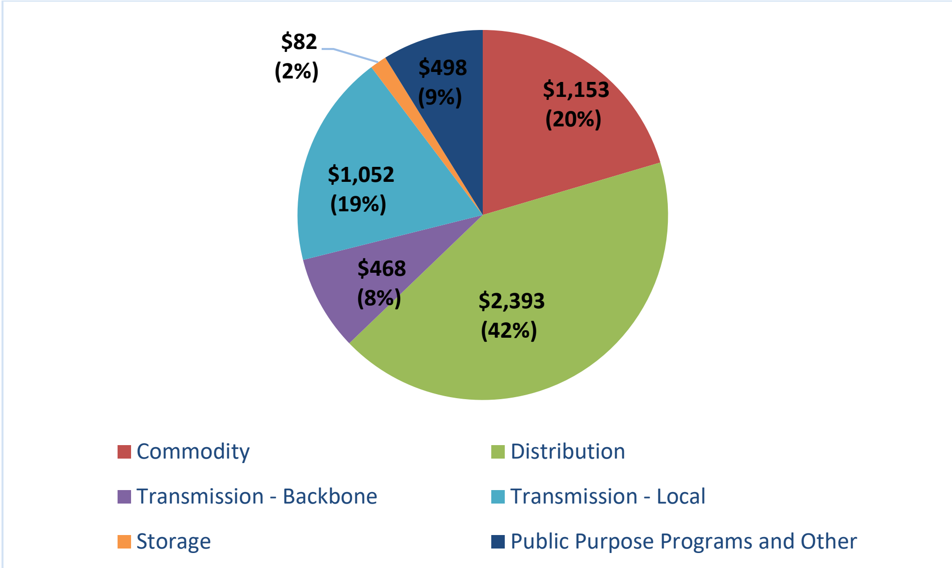
The distribution component accounts for the largest portion of PG&E's 2023 revenue requirement at 42 percent, followed by the commodity (20 percent), local transmission (19 percent), backbone transmission (8 percent) and storage (2 percent) components. PPP accounts for approximately 9 percent of the revenue requirement.

PG&E distribution and local transmission costs are collected via the transportation rate component of the gas bill. Core customers pay for an allocated share of backbone transmission and storage costs in the core gas procurement rate. PG&E core customers may also pay for storage obtained from independent storage operators in the procurement rate.

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

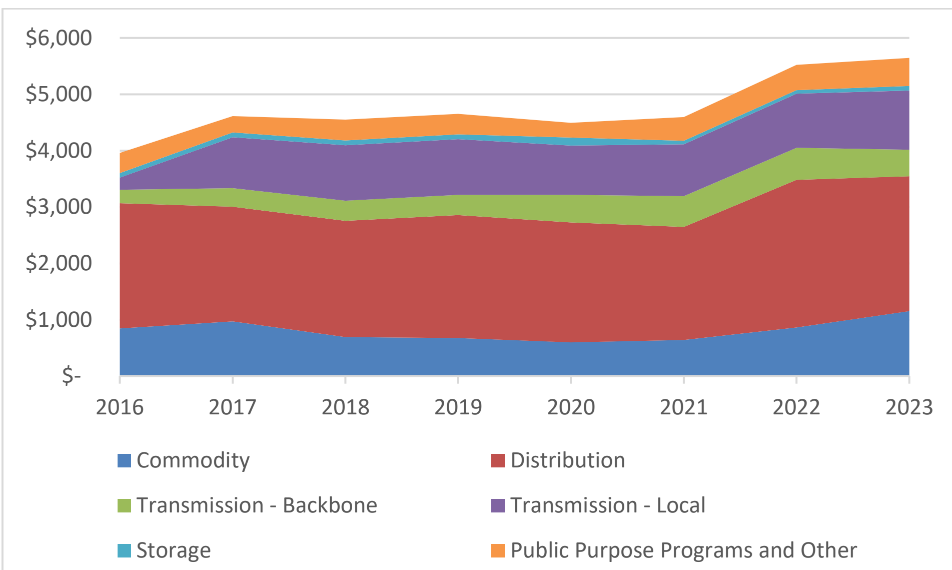
[261] SIMP requirements are set by PHMSA and CalGEM under 49 CFR, Part 192.12 and Title 14, Chapter 4, §1726 of the California Code of Regulations (CCR) respectively and are intended to identify and manage threats to the functional integrity of storage wells and reservoirs. Operators must periodically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

Figure 31: PG&E 2023 Revenue Requirement ($ millions)



PG&E's total gas operations revenue requirement increased by approximately 43 percent since 2016. From 2021 to 2023, PG&E's total gas operations revenue requirement increased by 2.3 percent. See Figure 32.

Figure 32: 2016–2023 PG&E January 1 Revenue Requirement by Rate Category ($ millions)[262]



[262] Data is from IOU responses to Energy Division SB 695 Report data requests, submitted to CPUC on 2/3/2022.

The underlying revenue requirement components changed by the following percentages from 2022 to 2023:[263]

- Commodity: +34 percent,
- Backbone transmission: -17 percent,
- Local transmission: +9 percent,
- Distribution: -9 percent,
- Storage: +32 percent, and
- Public Purpose Programs and other: +11 percent.[264]

The driver of the 34 percent increase to the gas commodity cost is due to the increases in the weighted average cost of gas purchases and in the cost paid to the independent storage providers. From November 2021 to January 2022 natural gas prices were 90 percent higher in PG&E's service area. The monthly average 2022 commodity price of 74.6 cents per therm was about 63 percent higher than the average 2021 commodity price of 45.9 cents per therm. See the section on the West-wide Increase in Gas Commodity Costs below for more information.

Distribution revenues include O&M and capital-related revenue requirements adopted in the GRC. Distribution revenues also include year-end balances from various regulatory accounts. PG&E projects a decrease in distribution expenses from 2022. The following are drivers for the projected decrease in 2023 Gas Distribution costs. First, a final decision on PG&E's 2023 General Rate Case (GRC) Phase 1 Application was not issued in time for the January 1 rate change, therefore, PG&E included the 2022 authorized base revenue requirements for its Gas Distribution (GD) and Gas Transmission & Storage (GT&S) functions based on the 2020 GRC (D.20-12-005) and 2019 GT&S (D.19-09-025) decisions, respectively. The gas distribution base revenue adjustment also includes the impact of the cost of capital decision in D.22-12-031. The revenue requirements for 2023 will be trued up following a final 2023 GRC decision. Secondly, the 2022 under-collection of $61 million was removed from the 2023 revenue requirement. Third, a $154 million revenue requirement in the Wildfire Expense Memorandum Account for 2022 does not apply and therefore was removed from the 2023 revenue requirement.

The backbone transmission system (BTS) is used to transport gas from PG&E's interconnection with interstate pipelines, other local distribution companies, and California Gas fields to PG&E's local transmission and distribution system. The 17 percent decrease in 2023 from 2022 backbone transmission costs is driven by the following factors. First, as mentioned above, the GT&S revenue requirements have been held flat, at 2022 authorized levels (adjusted by the impact of the cost of capital decision in D.22-12-031) due to a late decision in the 2023 GRC. Second, as authorized by

[263] Data is from IOU responses to Energy Division SB 695 Report data requests, submitted to CPUC on 2/3/2022.
[264] The natural gas PPP surcharge funds the following programs: Energy Efficiency (EE), Energy Savings Assistance (ESA), Statewide Marketing Education and Outreach, CARE, and public-interest R&D.

D.19-09-025, the 2019 GT&S rate case decision, PG&E trued up the balances in eight GT&S related accounts, resulting in a decrease of $137 million to backbone transmission function. This decrease is partially offset by an increase of $38.2 million, related to adoption of 2011-2014 GT&S capital expenditures in D.22-07-007.[265]

The local transmission system consists of the pipelines that accept gas from the BTS and transport the gas to the distribution system. Local transmission costs are included in customer gas transportation rates.

Storage includes core customer gas storage, carrying cost of working gas in storage for core customers, and unbundled storage. While storage GT&S function revenue requirements have been held flat, at 2022 authorized levels (less the impact of the cost of capital decision in D.22-12-031), pending a decision in the 2023 GRC, there is an increase of $19.8 million adopted in D.22-07-007.

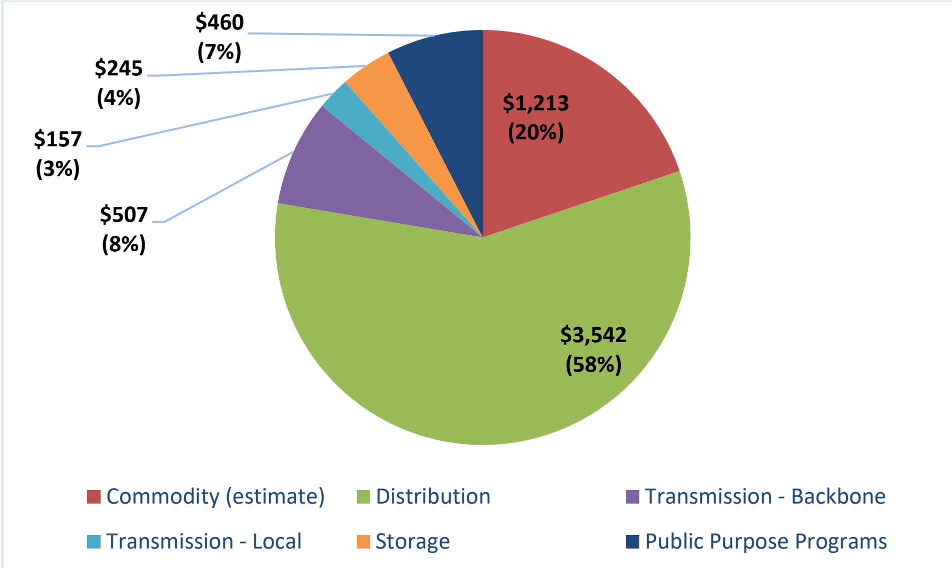
PPP revenues include the CARE discount collected from Non-CARE customers, EE program costs, gas CPUC Fee and the Natural Gas Greenhouse Gas Costs and Credit. The increase in revenue is driven by an increase in the EE authorized funding[266], an increase of $33 million in CARE balancing account under collection in 2022 compared to 2021, and a net increase of $21.5 million in GHG costs and revenues.

SoCalGas Revenue Requirement by Rate Category

The distribution component accounts for the largest portion of SoCalGas' 2023 revenue requirement, accounting for 58 percent, followed by the commodity (20 percent), backbone transmission (8 percent), storage (4 percent), and local transmission (3 percent) components. PPP accounts for 7 percent of the revenue requirement.

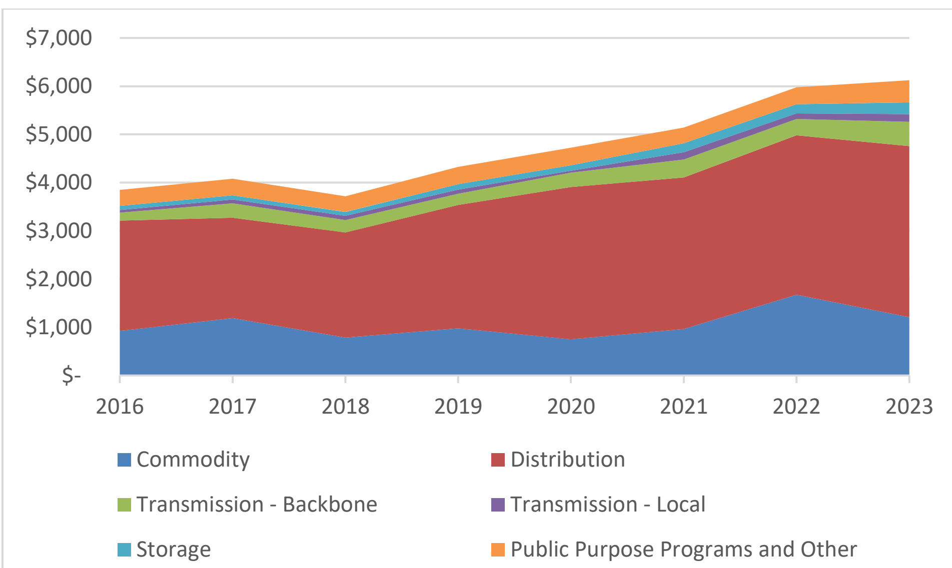
265 Decision approving Settlement Agreement on PG&E's 2011-2014 GT&S Capital Expenditures.
266 Advice Letter 4521.

Figure 33: SoCalGas 2023 Gas Revenue Requirement ($ millions)



Since 2016, SoCalGas' total revenue requirement has increased by about 59 percent. From 2022 to 2023, SoCalGas' total revenue requirement has increased roughly 2.5 percent. See Figure 34.

Figure 34: 2016–2023 SoCalGas January 1 Gas Revenue Requirement by Rate Category ($ millions)



Revenue requirement components changed by the following percentages from 2022 to 2023:

- Commodity: - 28 percent,[267]
- Backbone transmission: + 49 percent,[268]
- Local transmission: + 27 percent,
- Distribution: + 7 percent,
- Storage: + 30 percent
- Public purpose programs and other: + 32 percent.

SoCalGas projects lower commodity prices in 2023 will offset increases to the backbone transmission, local transmission, distribution, storage, and PPP revenue requirements. The total collected revenue in 2023, as such, is expected to increase by 2.5 percent relative to 2022.

The monthly average 2022 commodity price of 75.4 cents per therm was about 68 percent higher than the average 2021 commodity price of 44.8 cents per therm. During the 2022-2023 winter, natural gas prices in California were impacted by colder weather in the mid-continent and northwest which increased the overall demand for natural gas in the western region, higher LNG export to Europe and Asia, and lower interstate pipeline capacity to California due to the aftermath of the 2021 rupture of an El Paso pipeline near Coolidge, Arizona. Refer to the discussion on the Nationwide Increase in Gas Commodity Costs, below, for more information.

The primary drivers of SoCalGas' 2023 revenue requirement net increase include the following:

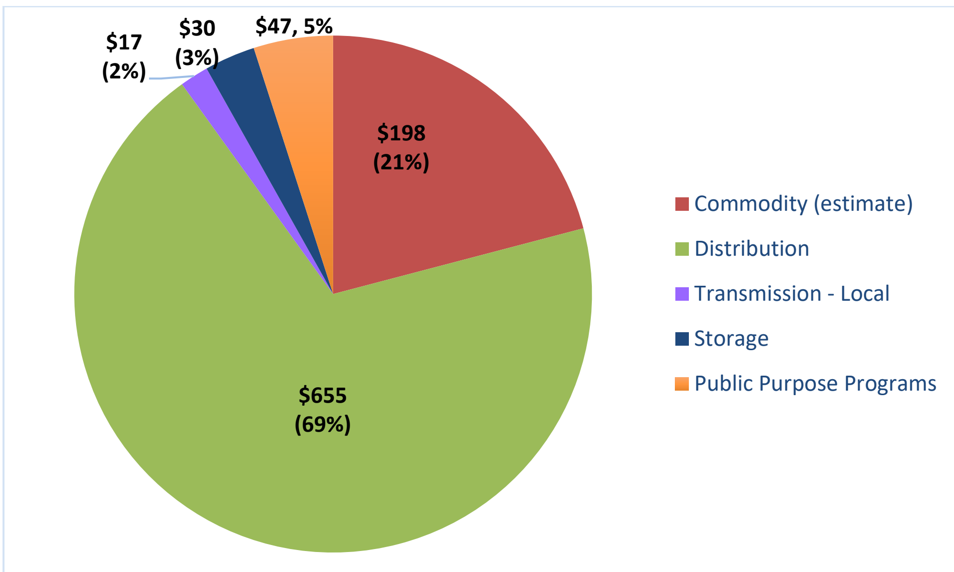
- Increases to SoCalGas regulatory accounts: a) $259 million related to transportation revenue requirement increases; b) $181 million and $36 million related to core and noncore customer revenue requirements, respectively.
- The 2023 GHG revenue requirements, a component of the Public Purpose Program charge, increase by $29 million.[269]
- Test Year 2019 General Rate Case attrition and cost of capital adjustments resulting in a $108 million increase.[270]
- A $57 million increase in 2023 revenue requirement due to tax adjustment.[271]

[267] In 2023, SoCalGas projects a 28% decrease in commodity costs ($1.21 billion) relative to its 2022 commodity costs of $1.67 billion. Cold weather, geopolitical conflict, and pipeline capacity constraints drove SoCalGas' commodity cost higher in 2022.
[268] The 49% shown here ($507 million) represents the SoCalGas' Backbone Transmission Surcharge (BTS) revenue requirement after system integration. Prior to system integration, SoCalGas' BTS revenue requirement is $446 million, and SDG&E's BTS revenue requirement is $61 million. SDG&E's Backbone Transmission revenue requirement is transferred from SoCalGas to SDG&E by Regulatory Accounting. The BTS rate is included in the SoCalGas and SDG&E Gas Core Procurement (G-CP) rates for Core customers.
[269] Advice Letter 6045-G.
[270] Advice Letter 6044-G.
[271] Advice Letter 6018-G.

SDG&E Revenue Requirement by Rate Category

Due to the integration of the SoCalGas and SDG&E gas systems, SDG&E's backbone transmission revenue requirement is recovered in SDG&E's core procurement rate.[272] The distribution component accounts for the largest portion of SDG&E's 2023 revenue requirement, accounting for 69 percent, followed by the commodity (21 percent), storage[273] (3 percent), and local transmission (2 percent) components. PPP accounts for 5 percent of the revenue requirement.

Figure 35: SDG&E 2023 Gas Revenue Requirement ($ millions)



SDG&E's total gas operations revenue requirement increased by approximately 64 percent since 2016, with a roughly 0.5 percent net increase from 2022 to 2023. See Figure 36.

Revenue requirement components[274] changed by the following percentages from 2022 to 2023:

- Commodity: - 27 percent,[275]
- Local transmission: +17 percent,
- Distribution: +13 percent,
- Storage: + 30 percent, and

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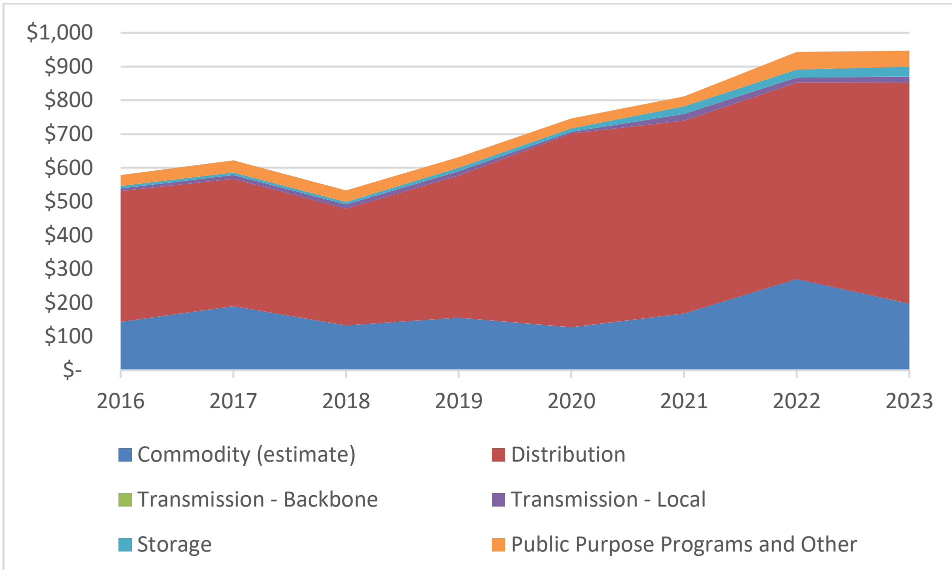
[272] SoCalGas' procurement department purchases gas on behalf of SDG&E's core customers. A Backbone Transmission Surcharge is included in SDG&E's core procurement rate which pays for the Backbone Transmission costs assigned to SDG&E's core customers.
[273] A percentage of SoCalGas' storage costs are allocated to SDG&E.
[274] SDG&E's backbone transmission revenue requirement is recovered through SDG&E's procurement rate.
[275] In 2023, SDG&E projects a 27% decrease in commodity costs ($198 million) relative to its 2022 commodity costs of $271 million. Cold weather, geopolitical conflict, and pipeline capacity constraints drove SDG&Es' commodity cost higher in 2022.

- Public Purpose Programs and other: -10 percent.

Figure 36: 2016–2023 SDG&E January 1 Gas Revenue Requirement by Rate Category ($ millions)



SDG&E projects its gas purchase costs to decrease by 27 percent from 2022 to 2023. SDG&E also projects its distribution revenue requirement will increase by 13 percent due to cost amounts reflected in newly added regulatory accounts: a) $29 million in the Customer Information System Account (CISBA) and b) $11 million in the Transition of Stabilization and OCM Balancing Account (TSOBA-G); and the $16 million included in the Core Fixed Cost Account (CFCA).[276] SDG&E expects its local transmission and storage revenue requirements to increase by 17 percent and 30 percent due to higher transmission and storage costs in the updated TCAP studies.[277] Public Purpose Program costs will decrease by 10%.

The primary drivers of SDG&E's 2023 revenue requirement net increase include the following:

- Adjustments to SDG&E Annual Update of Regulatory Accounts total of $32 million increase including: a $22 million increase in core customer regulatory account amortizations, a $17 million increase in noncore customer regulatory account amortizations, a $7.6 million increase in SoCalGas' transportation cost, a $1.1 million increase in CU/UAF, and other decrease adjustment of ($16) million.[278]

[276] Advice Letter 3129-G.
[277] Advice Letter 3042-G.
[278] Advice Letter 3129-G and 3129-G-A.

- Test Year 2019 General Rate Case attrition and cost of capital adjustments, resulting in a $8 million increase.[279]
- A $5 million increase in 2023 revenue requirement due to the tax adjustment.[280]
- Transition, Stabilization and Organizational Change Management Balancing Account (TSOBA costs) of $11 million.[281]
- Cost recovery of Customer Information System Balancing Account (CISBA) Costs of $28 million.[282]

West-Wide Increase in Gas Commodity Costs

Unlike the process for electric utilities, the CPUC does not set an annual authorized revenue requirement for natural gas utilities' procurement costs. Instead, core procurement rates are adjusted monthly and are intended to recover monthly forecasted utility gas procurement costs. Gas commodity prices can be volatile and difficult to forecast. Calculating the procurement rate monthly provides a price signal to customers, who may choose to reduce their usage when procurement rates are high to achieve savings on their gas bills.

Core procurement costs include the various costs associated with procuring natural gas supplies for a utility's core gas customers, such as the cost of the commodity, interstate pipeline capacity costs, hedging costs, and other costs. However, the major component of core procurement costs is the cost of the commodity itself, which can be highly variable.

Utilities purchase natural gas through wholesale gas markets in which prices fluctuate based on national gas market conditions. The rates are based on a 30-day forecast of natural gas market prices. The utilities recover only the cost of purchased gas with no mark-up. The price of natural gas is not regulated at the state level by the CPUC or at the national level by the Federal Energy Regulatory Commission (FERC)—the market determines the price. However, the CPUC has created incentive mechanisms to encourage utilities to get the best possible prices for customers: SoCalGas' Gas Cost Incentive Mechanism (GCIM) and PG&E's Core Procurement Incentive Mechanism (CPIM). More information on these mechanisms can be found in the Costs and Rates Containment section below.

International, national, and regional events caused the price of natural gas to skyrocket during winter 2022-23. Fossil natural gas supply is increasingly a global commodity. First, exports of liquified natural gas (LNG) have increased significantly due to the war between Russia and Ukraine and the global realignment of fossil natural gas markets. This realignment put pressure on United States

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279 Advice Letter 3128-G.
280 Advice Letter 3113-G.
281 Advice Letter 3040-G.
282 Advice Letter 3039-G.

fossil natural gas markets in 2022, increasing prices overall, especially during the first nine months of the year.

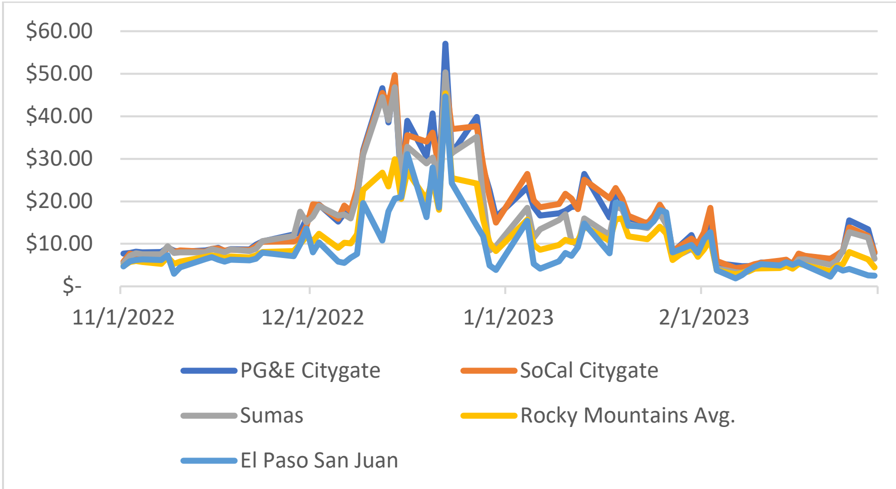
Second, the Pacific region had its sixth coldest November since 1950 followed by a cold December. Consistently cold temperatures across the West led to high customer demand for natural gas and a sustained drawdown of gas storage fields in the Pacific region. This is critical because gas storage fields provide the utilities an alternative to purchasing expensive gas supplies. Cold weather, high demand, and low storage led to high gas prices in western states including Washington, Oregon, Wyoming, Arizona, Nevada, and Colorado, as well as California. The cold in the West contrasted with generally warm weather east of the Rockies. Despite beginning winter below the five-year average,[283] national storage inventories were buoyed by above normal temperatures and were able to catch up. By mid-March, national storage inventories were 23.7 percent above the five-year average,[284] which had the effect of lowering gas prices outside the West. In contrast, by mid-March, Pacific storage was 56.4 percent below the five-year average.[285]

Third, there were multiple outages on the El Paso interstate pipeline system that supplies gas to California, resulting in less gas available to purchase. The increased demand, combined with the outages on interstate gas pipelines and declining gas storage inventory, contributed to these historic commodity prices.

The figure below illustrates daily natural gas wholesale prices at various western trading hubs including the PG&E Citygate, SoCal Citygate,[286] Sumas (Canada-Washington border), Rocky Mountain Region (Wyoming) and El Paso-San Juan (New Mexico). As shown in Figure 37, the PG&E and SoCal Citygate fossil natural gas prices trended very closely with regional prices.

[283] EIA Weekly Natural Gas Storage Report for the week ending Nov. 9, 2022: https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2022/11_10/.
[284] EIA Weekly Natural Gas Storage Report for the week ending March 10, 2023: https://ir.eia.gov/ngs/ngs.html.
[285] EIA Weekly Natural Gas Storage Report for the week ending March 10, 2023: https://ir.eia.gov/ngs/ngs.html.
[286] The Citygate is any point at which the backbone transmission system connects to the local transmission and distribution system. The Citygate is not one specific, physical location and represents a virtual trading point on the natural gas system.

Figure 37: Natural Gas Prices (in MMBtu) at Western Gas Hubs



Graph Source: [NGI]

Between 2021 and 2022, average daily December fossil natural gas wholesale prices increased by 514 percent at PG&E Citygate and 416 percent at SoCal Citygate. The fossil natural gas wholesale price drives California's retail fossil natural gas price trends and impacts gas procurement rates.

The extremely high gas prices of winter 2022 can be seen in Figure 38 below, which compares July 2022 to February 2023 monthly natural gas prices at PG&E Citygate and SoCalGas Citygate to the same months in July 2021-2022.

Figure 38: Natural Gas Average Monthly Prices per MMBtu

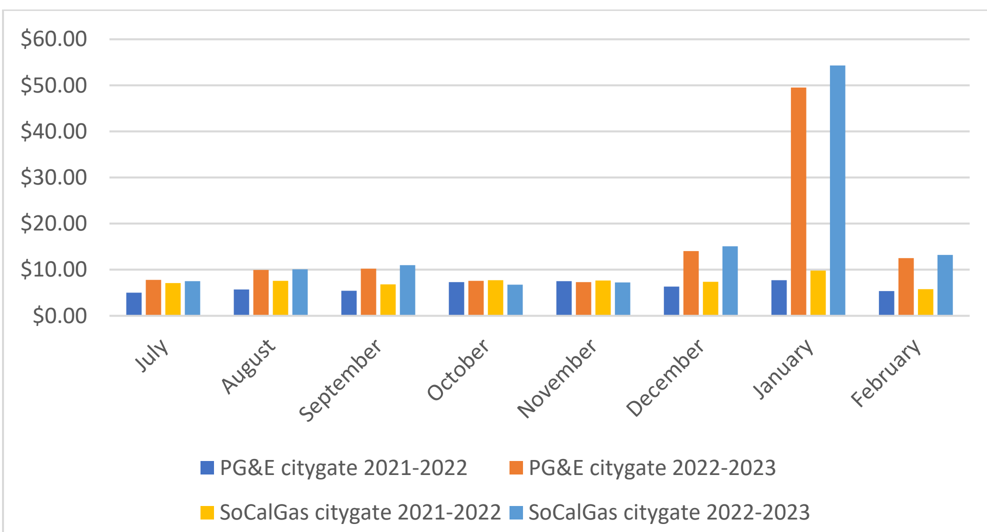
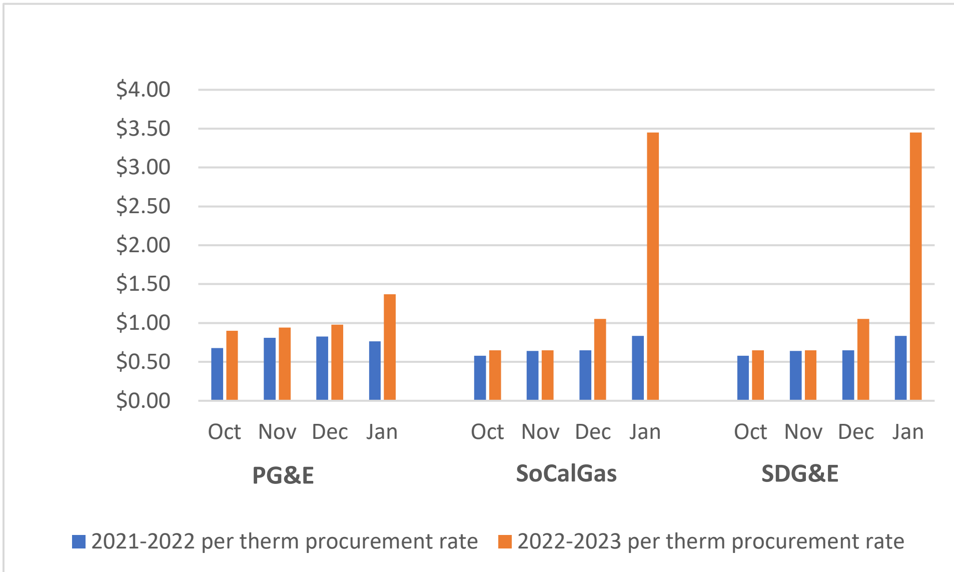


Figure 39 compares the monthly Procurement Rates paid by core customers for PG&E, SoCalGas, and SDG&E in 2021 and 2022.

Figure 39: PG&E, SoCalGas, SDG&E Gas Procurement Rates per Therm Oct 2021-Jan 2022 vs Oct 2022-Jan 2023



Average Rates by Customer Class

A breakdown of average rates by core customer class is shown for SoCalGas, SDG&E, and PG&E in Figures 40–42. Each class shows an upward trend during this period (2016 to 2023). Residential, small, medium, and large business customers (core customers) pay higher rates than non-core customers because core customers are more expensive to serve and require greater reliability.[287] The fixed costs of serving larger customers are recovered over a larger number of therms, due to their higher usage, which results in lower rates per therm. The bundled average rates for core customers include a customer or minimum charge,[288] procurement, transportation, and the PPP surcharge. CARE residential customers get a 20 percent discount off the entire natural gas bill.

[287] Non-core customer rates include the access charge, transportation rate (levels often based on volume of service), and gas PPP surcharge (but not for Electric Generation customers).
[288] SoCalGas imposes a $5 fixed charge, while SDG&E and PG&E impose a $4 minimum charge.

Figure 40: SoCalGas Gas Average Rates per Therm by Class in Effect January 1 (2016-2023)

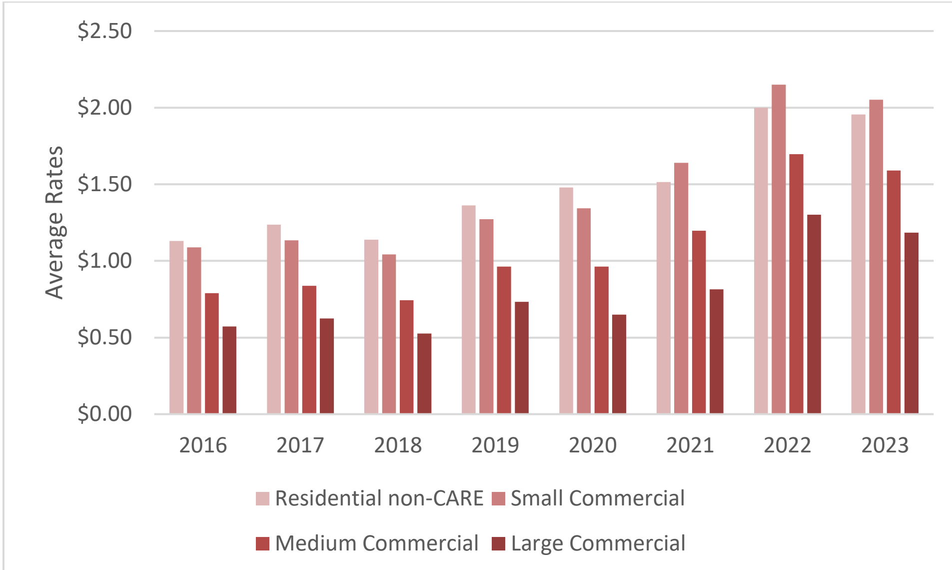


Figure 41: SDG&E Gas Average Rates per Therm by Class in Effect January 1 (2016-2023)

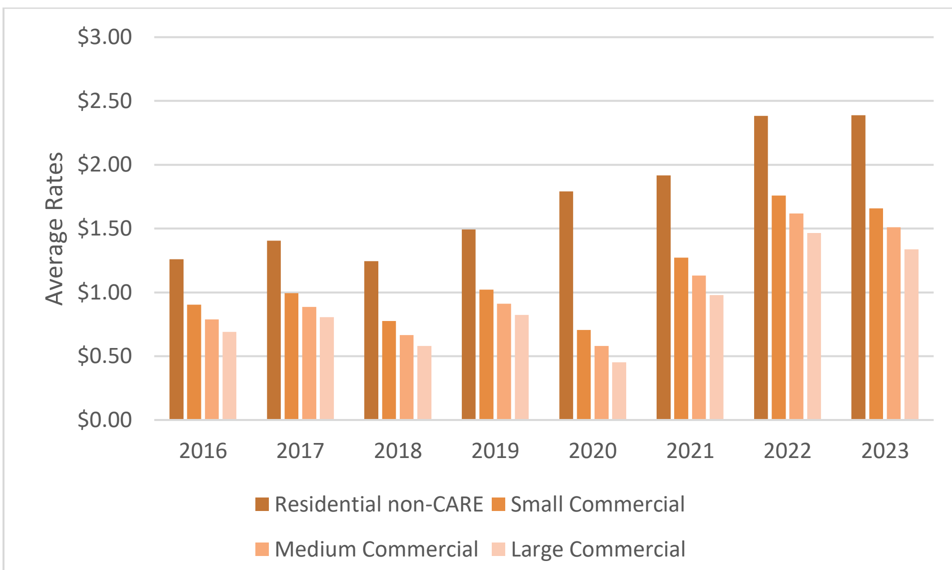
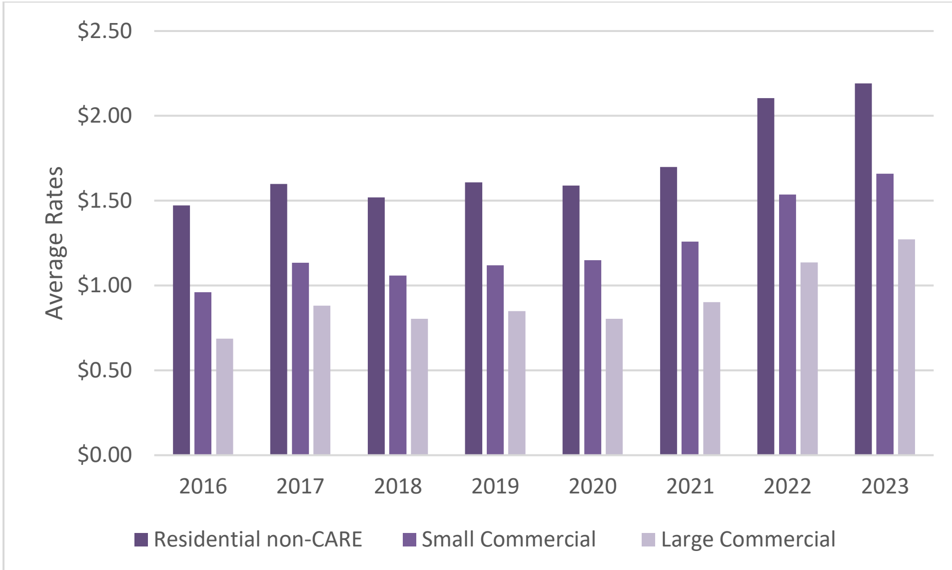


Figure 42: PG&E Gas Average Rates per Therm by Class in Effect January 1 (2016-2023)



Costs and Rates Containment

The CPUC has undertaken actions in the preceding 12 months (May 1, 2021 – April 30, 2022) and is taking actions in the succeeding 12 months (May 1, 2022–April 30, 2023) to limit utility costs and rate increases through scrutiny of gas utility revenue requirements in various proceedings. This section presents CPUC decisions made in the past 12 months and pending proceedings in which utilities have made requests for cost recovery that could increase rates.

PG&E

GRC Review

PG&E filed its first combined GRC/GT&S on June 30, 2021, to request gas rate approvals for 2023 through 2026 (A.21-06-021). PG&E seeks the following revised amounts in its latest testimony: $4.706 billion, $5.220 billion, $5.643 billion, and $6.099 billion for 2023, 2024, 2025 and 2026, respectively, in revenues for its gas distribution, transmission and storage operations.[289] These amounts represent increases of 15 percent, 28 percent, 38 percent and 49 percent in 2023, 2024, 2025 and 2026, respectively, from PG&E's 2022 adopted gas revenues. PG&E's proposed gas revenues comprise 31 percent of its utility-wide total GRC proposed revenues beginning in 2023, rising to 35 percent by 2026. The costs and revenue requests presented in this GRC were rigorously reviewed and some were challenged by intervenors. The CPUC is currently assessing the merits of the utility's requests, with a decision expected this year.

[289] PG&E Errata Testimony in A.21-06-021 which "Includes Errata Through August 8, 2022", Exhibit PG&E-11-E, Ch. 2, p. 2-2, Table 2-1.

Gas Cost Allocation and Rate Design (CARD)

In D.20-12-002, the final decision in the Rate Case Plan (RCP) proceeding, the Commission combined the GRC and revenue requirement component of the Gas Transmission and Storage (GT&S) proceeding. The cost allocation and rate design components of the GT&S were separated and placed in a new CARD proceeding filed September 30, 2021. With this, PG&E maintains two proceedings for gas cost allocation and rate design as has been the case since 1998's Gas Accord 1. The Gas Cost Allocation Proceeding (GCAP) covers cost allocation and rate design for distribution while CARD covers these for transmission and the unbundled gas marketplace, including storage. The revenue allocation and rate design approved in CARD will implement rates based on the revenue requirement pending approval in PG&E's 2023 GRC, Phase 1 Track 1 Application (A.21-06-021).

PG&E has requested flexibility to later take account of the impact of variables which may affect PG&E's proposal. These include major revisions of revenue requirement of PG&E's 2023 GRC, changes following review of the CARD filing by Core Gas Supply (CGS), and implications of the final decision in R.20-05-003, the rulemaking to continue Electric Integrated Resource Planning (EIRP) and related procurement processes that adopts a new Preferred System Plan (PSP). Further, PG&E filed revised CARD testimony on August 18, 2022, to address two additional issues identified in scope: (a) safety considerations potentially impacted by this Application and (b) Environmental and Social Justice (ESJ) issues potentially impacted by this Application.

Gas Procurement Costs Incentives

The Core Procurement Incentive Mechanism provides PG&E with a financial incentive to purchase and transport gas for core ratepayers at a cost that is equal to, or less than, prevailing market prices. The CPIM compares actual monthly purchased gas costs (commodity and transportation) to monthly benchmarks over a 12-month (November to October) period.

On June 3, 2022, PG&E submitted its CPIM performance report, which covered the period November 19, 2019, though October 31, 2020 (Year 27). The report stated that PG&E's core gas costs and reservation charges were $17,850,817 below the CPIM benchmark and that, according to the mechanism, the savings should be split with $15,172,842 going to ratepayers and $2,677,975 to shareholders. On January 25, 2023, the CPUC's Public Advocates Office issued its Monitoring and Evaluation Report for the Year 27 CPIM, which confirmed the total savings, shareholder award, and ratepayer benefits as presented in the report. On February 8, 2023, PG&E submitted Advice Letter 4712-G requesting approval of the $2.7 million shareholder reward. The Advice Letter is currently pending approval. PG&E's recorded gas costs were $18 million below the benchmark, which, if approved, will result in core ratepayer gas commodity costs that were $15 million below the prevailing market price.

Recovery of 2011-2014 GT&S Capital Expenditures

On July 31, 2020, PG&E filed A.20-07-020 requesting cost recovery of $512 million for gas transmission and storage (GT&S) capital expenditures that it incurred in 2011 to 2014 above the costs that the Commission had authorized in D.11-04-031.

PG&E previously requested recovery of these GT&S capital expenditures in PG&E's 2015 GT&S rate case (A.13-12-012). Decision 16-06-056 disallowed the recovery of these capital expenditures but allowed PG&E to seek recovery of these GT&S costs in a future application, after the Commission's Safety and Enforcement Division (SED) or a third party performs an audit of the reasonableness of these costs. SED completed the audit and issued a report (Audit Report) with its findings confirming the costs, on June 2, 2020.

PG&E sought approval for $512 million in 2011-2014 GT&S capital expenditures that D.16-06-056 ordered for further review and certification. These capital expenditures translate to $416.3 million in revenue requirement. Certain parties to the proceeding filed a joint motion on July 7, 2021, for approval and adoption of a settlement agreement among the settling parties.

On July 14, 2022, the Commission approved the parties' settlement agreement reducing PG&E's requested capital expenditures $356.3 million in revenue requirement and increased PG&E's requested amortization period of 36 months by an additional 24 months.[290]

SoCalGas and SDG&E

GRC Additional Years' Revenues

In April 2020, SoCalGas and SDG&E filed a joint petition to modify the decision from their 2017 GRC to extend it two additional years (also known as "attrition years") as directed in the January 2020 Rate Case Plan decision.[291] The CPUC issued D.21-05-003 in May 2021, authorizing SoCalGas' revenue requirement adjustments of $142.1 million for 2022 (4.53 percent increase) and $130.2 million for 2023 (3.97 percent increase) and SDG&E's revenue requirement adjustments of $87.3 million for 2022 (3.92 percent increase) and $85.6 million for 2023 (3.70 percent increase). The total revenue requirements authorized were $2.3 and $2.4 billion for SDG&E and $3.3 and $3.4 billion for SoCalGas for 2022 and 2023, respectively. These revenue requirements are slightly less than the original utilities' requests made in the petition. The CPUC proposed and adopted an updated escalation factor index to determine the amount of revenues to be collected for those two additional years, which reflects the impacts of COVID-19 pandemic on ratepayers. This reduced the utilities' initial requested relief by $12.9 million and $19.5 million for SoCalGas and $7.1 million and $29.8 million for SDG&E, for 2022 and 2023, respectively. These revenue requirement reductions resulted in lower rate impacts for customers.

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[290] *See* D.22-07-007.
[291] *See* D.20-01-002.

2024 GRC

On May 16, 2022, SoCalGas and SDG&E submitted their 2024 GRC requesting to revise the authorized revenue requirement to recover costs of the utilities gas operations, facilities, and infrastructure and other functions necessary to provide utility services to their customers. SoCalGas requests a $4.398 billion revenue requirement, to be effective January 1, 2024, an increase of $738 million or 20.2 percent increase over the expected 2023 revenue requirement. This results in an estimated bill impact of 13.2 percent for SoCalGas non-CARE residential gas customers in 2024 compared to 2023. For the remaining years in the GRC cycle (post- test years, PTY), 2025 to 2027, SoCalGas is requesting additional revenue increases of $295 million (6.7 percent) in 2025, $261 million (5.6 percent) in 2026, and $379 million (7.7 percent) in 2027.

SDG&E requests a $2.996 billion ($2.332 billion for electric and $664 million for gas) revenue requirement, to be effective January 1, 2024, an increase of $449 million or 17.6 percent increase over the expected 2023 revenue requirement. This results in an estimated bill impact of 5.3 percent for SDG&E electric residential customers and 17.5 percent for gas residential customers in 2024 compared to 2023. For PTYs 2025-2027, SDG&E is requesting additional revenue increases of $315 million (10.5 percent) in 2025, $306 million (9.2 percent) in 2026, and $279 million (7.7 percent) in 2027. In the GRC, party intervenors will review the costs presented and revenues requested by the utilities and challenge costs as they see fit. The CPUC will assess the merits of all the parties' positions and make its decision taking into account safety, reliability and affordability.

Gas Cost Incentives

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

On June 15, 2022, SoCalGas submitted an application stating that its core procurement costs for the period April 1, 2021, through March 31, 2022, (Year 28), were $122,216,733 below the benchmark and seeking approval of a shareholder reward of $22,313,352 for its performance. On October 15, 2022, the CPUC's Public Advocates Office issued its Monitoring and Evaluation Report for Year 28 of the GCIM, which confirmed the total savings, shareholder award, and ratepayer benefits as presented in the application. A.22-06-005 is currently pending. SoCalGas' recorded gas costs were $122 million below the benchmark, which, if approved, would result in core ratepayer gas commodity costs that were $100 million below the prevailing market price.

Cost Allocation Proceeding (CAP)

On September 30, 2022, Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) filed their Cost Allocation Proceeding (CAP) application to revise rates for gas services, and to implement gas storage related proposals effective January 1, 2024, through

December 31, 2027. In addition, in this application, SoCalGas and SDG&E proposed to move the CAP to a four-year cycle (instead of the three-year cycle of the previous Triennial Cost Allocation Proceeding (TCAP)), to match the cycle of what is now used for the GRC.

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

Aliso Canyon Order Instituting Investigation

On February 9, 2017, the CPUC opened the Aliso Canyon proceeding, Investigation I.17-02-002, as directed by SB 380 (Pavley, 2016). SB 380 required the CPUC to "determine the feasibility of minimizing or eliminating the use of the SoCalGas Aliso Canyon Natural Gas Storage Facility (Aliso Canyon) while still maintaining energy and electric reliability for the region." This facility is the largest of four gas storage facilities serving southern California. The CPUC has modeled the current gas system, finding that the Aliso Canyon facility is currently necessary for winter reliability and cost containment.

A third-party consultant modeled the costs and benefits of adding new infrastructure that would allow Aliso Canyon to be closed by 2027 or 2035. The consultant modeled several different infrastructure portfolios, including gas infrastructure upgrades, new electricity transmission, increased energy efficiency and building electrification, and additional electric generation and storage. This analysis concluded that any of these portfolios could successfully replace the services provided by Aliso Canyon. The consultant found that any of the portfolios modeled, except for new gas infrastructure, would result in a net decrease in energy system costs, when factoring in the costs of compliance with the Cap-and-Trade Program and Renewable Portfolio Standard, because the benefits of using the new resources would outweigh the investment costs. However, on balance the savings would accrue to gas ratepayers, while electricity ratepayer costs would increase. This analysis did not address costs or usage of the Aliso Canyon site itself.

In September 2022, the CPUC published a staff proposal presenting a framework to replace Aliso Canyon in the coming years using a combination of non-gas-fired electricity generation and storage, building electrification, and energy efficiency. Based on the contractor's modeling, the staff proposal estimates that starting from 2023 forecasts, an annual reduction of 214 million metric cubic feet per day (MMcfd) in forecast peak gas demand (i.e., 5 percent of the 2027 peak day demand), or an annual increase of 1,084 megawatts of non-gas-fired electric generation and storage capacity, or some combination of both, will be necessary to reliably serve all energy demand in 2027 without the use of Aliso Canyon. Some of this reduction is already forecast to occur, and procurement would be necessary to make up the difference.

The staff proposal also suggests biennial reassessment of gas and electric system reliability to gauge progress and potential changes to the maximum amount of gas stored at Aliso Canyon based on the reassessment. The CPUC increased the maximum inventory level for the facility in November 2021 to protect "gas and electricity customers from reliability and economic impacts."[292] That level will remain in place until the CPUC issues a new decision in the proceeding.

The proceeding remains open, with the CPUC yet to determine whether to order that Aliso Canyon be closed and, if so, what infrastructure will be procured to allow that closure and what the timeline and other parameters will be. The CPUC anticipates a decision in this proceeding during 2023.

Line 1600 Repairs and Replacement

In A.15-09-013, SoCalGas and SDG&E applied for a Certificate of Public Convenience and Necessity (CPCN) for the construction of a new transmission pipeline, Line 3602. The utilities also proposed to reclassify an existing transmission pipeline, Line 1600, from transmission to distribution to avoid potential customer rate impacts due to required pressure testing. In Phase One of the proceeding, the CPUC evaluated the need for the proposed project pertaining to safety, reliability, resiliency, and operational flexibility and to resolve basic planning assumptions and standards that may inform the California Environmental Quality Act (CEQA)/National Environmental Policy Act (NEPA) process. On June 21, 2018, the CPUC denied SDG&E's and SoCalGas' request for a CPCN for the proposed Line 3602 project.[293]

The CPUC opened a second phase to review cost forecasts pertaining to the SoCalGas/SDG&E's Line 1600 PSEP.[294] Under the approved plan, SoCalGas/SDG&E will replace segments of the line located in high consequence areas and hydrotest parts of the line located in non-high consequence areas. The project is estimated to cost $677 million, with $630 million anticipated to be capital expenditures and $47 million estimated to be operating expenses. Phase 2 of this proceeding will enable the CPUC to provide appropriate guidance regarding the reasonableness of the cost estimates, cost containment strategies, ratemaking and accounting treatment. D.20-02-024 did not grant cost recovery in this phase; however, reasonableness review of the cost forecasts established in this phase will occur in later GRCs.

On December 3, 2020, the CPUC denied the rehearing of D.20-02-024 with modifications. The modification rejected the Intervenor's request to consider the basis for the cost of the full hydrotest

[292] See D.21-11-008, Conclusion of Law 1: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M421/K086/421086399.PDF.
[293] *See* D.18-08-028.
[294] *See* D.20-02-024.

alternative during the second phase of the proceeding and states that because Design Alternative 1 is in effect as legally required, the cost of a different alternative is not relevant. Design Alternative 1 consists of replacing pipeline in high consequence areas and hydrotesting in non-high consequence areas, which the CPUC's Safety and Enforcement Division formally approved on January 15, 2019. The reasonableness of forecasts established in this phase will be reviewed in later applicable GRCs. This cost forecasts review proceeding is ongoing.

Angeles Link Application

On December 15, 2022, the Commission approved D.22-12-055 authorizing SoCalGas to record in a memorandum account up to $26 million in feasibility study costs for its proposed Angeles Link dedicated clean renewable hydrogen pipeline project. D.22-12-055 did not determine how those costs would be recovered, but it said that SoCalGas could request cost recovery from ratepayers in a future proceeding if the memorandum account is approved. The decision did allow SoCalGas to record 15 percent more in costs over the $26 million cap by filing a Tier 2 Advice Letter. The application stated that the project had to be approved prior to SoCalGas's next GRC due to the urgent climate benefits that the project would bring. The anticipated costs for the proposed memorandum account do not include construction or capital costs. The application referenced the use of underground hydrogen transportation infrastructure and "new in-state dedicated hydrogen pipelines," suggesting much of the pipeline will be new infrastructure built underground.

The application stated that the project is designed to facilitate the closure of the Aliso Canyon methane storage facility and preserve energy reliability, as well as address overall climate change concerns. The application did not name specific end users of the renewable hydrogen, but it described an intent to serve future green hydrogen end users, including "hard-to-electrify" industries, electric generators, and the heavy-duty transportation sector. The application stated that the foundation of the system would be one or more transmission pipelines that would run from generation sources in areas such as the Central Valley, Mojave Desert/Needles, or the Blythe area. The application did not specify how the hydrogen would be produced other than that it would come from electrolysis powered by renewable electricity.

The application described three phases for the project. Phase 1 would last from 12 to 18 months and cost an estimated $26 million. It would support a pre-Front End Engineering and Design analysis assessing green hydrogen demand, identifying end users, and conducting energy studies, in addition to engaging stakeholders. Phase 2 would last from 18 to 24 months and cost $92 million. It would identify a preferred option through design, engineering, and environmental studies and complete refined engineering and implementation plans. Phase 3 would last from 18 to 30 months and cost "several hundreds of millions of dollars." This phase would prepare permit applications, including an application to the CPUC for a Certificate of Public Convenience and Necessity and other long-lead permit applications.

All Investor-Owned Utilities

Long-Term Gas Planning Rulemaking

On January 16, 2020, the CPUC opened a rulemaking[295] to initiate long-term planning procedures for the California natural gas system. The goal of the proceeding is to ensure safe, reliable, and affordable gas service as fossil gas consumption declines in support of California's climate goals. As noted above, rates are derived by dividing the revenue requirement by sales. As total gas sales decline, rates per therm will go up unless the revenue requirement also declines. Thus, cost containment in an era of declining fossil gas use requires strategic planning to reduce the revenue requirement. Increased coordination between GHG reduction activities and gas system planning will support cost containment.

The rulemaking has two tracks. Track 1 established baseline standards and addressed issues of immediate concern. These included: determining that the existing reliability standards are still adequate; harmonizing the Operational Flow Order (OFO) penalty structure across the state; and setting a minimum in-service standard for backbone pipeline capacity and creating a citation program for not utilities not meeting that standard. The OFO Decision was issued on April 22, 2022. The Decision on the remaining Track 1 issues was issued on July 14, 2022.

Track 2 focuses on long-term system planning. Track 2a focuses on gas infrastructure. Its goal is to create new criteria for the CPUC to use when evaluating utility requests for spending on infrastructure as well as for proactively identifying distribution pipelines that can be decommissioned. Building electrification can reduce gas system costs if it allows gas distribution pipeline segments to be retired, which is greatly enhanced if the electrification is geographically concentrated.

In December 2022, the CPUC issued a staff proposal outlining a path for the proactive decommissioning of distribution pipelines, which identifies environmental health, pipeline risk minimization, and affordability as goals when determining where to focus building decarbonization. Based on these goals, the proposal suggests using five tranches to geographically prioritize areas for "electrification zones" and targeted gas distribution pipeline decommissioning. The staff proposal also proposes enhanced CPUC data collection and review of gas distribution system maintenance and non-pipeline alternatives. The proposal does not address pilot projects.

Regarding gas transmission infrastructure, this proceeding seeks to find a balance in which California has sufficient transmission and storage infrastructure to avoid creating reliability issues and scarcity that drive up gas commodity prices while at the same time avoiding unneeded investments that could lead to stranded assets. In December 2022, the CPUC adopted Gas General Order 177, which requires utilities to request a Certificate of Public Convenience and Necessity and conduct CEQA analysis before building certain large gas infrastructure projects if they are not emergency

[295] *See* R.20-01-007.

projects and will affect criteria emissions. This order increases CPUC oversight of gas transmission infrastructure, bringing it in line with the CPUC's oversight of electric transmission infrastructure.

The CPUC is preparing to consider infrastructure planning further in tracks 2b and 2c. Track 2b focuses on equity, rates, safety, and workforce issues. The equity portion focuses on barriers low-income customers face in electrifying and what the CPUC can do to mitigate those barriers. The rates portion will look at ratemaking strategies to mitigate the impact of the gas transition on customer rates both now and in the future. The safety portion will look at ways to streamline safety spending where possible, given that most safety spending is required by state or federal agencies. Track 2c is scheduled to focus on data and process, considering a long-term strategy for managing gas planning going forward.

Current Gas Market Conditions and Impacts on Electricity Markets

The CPUC held a public En Banc on February 7, 2023, to gather facts on the extent of, and reasons for, high gas prices this winter. The CPUC gathered critical data during the En Banc, including the following:

- Gas prices for delivery on December 22, 2022, were nearly seven times higher compared to the same day in 2021.
- The price spikes were not unique to California and were experienced in other Western gas markets as well, including in Nevada and Arizona.
- California gas utilities had to rely heavily on storage inventory to meet the increased heating demand brought on by cold weather early in the winter season.
- High gas costs have led to high electric prices in the CAISO Market and the Western Energy Imbalance Market compared to 2021-2022. CAISO has estimated that electricity prices were $3 billion over the norm in December 2022.

The CPUC opened an Order Instituting Investigation (OII) on March 16, 2023, to continue fact-gathering efforts on the causes of the extraordinarily high gas prices; to investigate whether the utilities' communications were sufficient; and to explore potential solutions to avoid similar events in the future and minimize their impacts if they do occur.

Rulemaking to Implement Dairy Biomethane Pilots

Pursuant to SB 1383 (Lara, 2016), the CPUC opened a rulemaking[296] to establish dairy biomethane natural gas pipeline injection demonstration projects. In 2018, the CPUC along with the Air Resources Board and the Department of Food and Agriculture, put forth a pilot solicitation and selected six projects for construction. Contracts between utilities and developers of the six pilot projects were signed, and the new dairy biomethane facilities have started converting biogas from dairy digesters into renewable natural gas (RNG) for heating and transportation purposes in an

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

effort to move California closer to its goal of reducing methane emissions by 40 percent below 2013 levels by 2030. The pilots will undergo evaluation processes to determine GHG reduction levels and project goal attainment. Forecasted costs associated with the six pilot projects are estimated to be approximately $133 million, and utilities are required to seek prior authorization from the CPUC for any deviation from the original cost estimates. Due to delays experienced as a result of the COVID-19 pandemic, the first of these projects was adjusted to come online in 2021 and the last of these projects is projected to come online in the third quarter of 2023. As of the end of 2022, only one of the six projects – Weststeyn – was not yet online.

Biomethane Procurement Considerations (SB 1440 Implementation)

In response to SB 1440 (Hueso, 2018), on February 24, 2022, the Commission adopted a biomethane procurement standard in D.22-02-025. The decision established biomethane procurement targets crafted to help achieve the state's Short-Lived Climate Pollutant (SLCP) reduction goals, which call for a 40 percent reduction in methane and other SLCPs by 2030. Biomethane procurement will reduce otherwise uncontrolled methane and black carbon emissions in California's waste, landfill, agricultural, and forest management sectors. The short-term 2025 biomethane procurement target is 17.6 billion cubic feet of biomethane, which corresponds to 8 million tons of organic waste diverted annually from landfills. Each utility will be responsible for procuring a percentage of the total diversion obligation in accordance with its proportionate share of natural gas deliveries. The medium-term 2030 target is a Renewable Gas Standard that requires biomethane procurement at 12.2 percent of current residential and small business (i.e., "core") gas usage in 2020, which equates to 72.8 billion cubic feet per year for California's four largest gas IOUs, collectively. Various other requirements in the procurement program are designed for environmental and social justice, public safety, and methane leak reduction. To protect ratepayers from unreasonable bill increases, the Commission in late 2022 approved a Standard Biomethane Procurement Methodology to ensure that all biomethane contracts are appropriately priced and further required that the gas IOUs submit Renewable Gas Procurement Plans in order for the Commission to vet anticipated future costs. PG&E, SoCalGas, SDG&E, and Southwest Gas filed the Renewable Gas Procurement Plans mandated by D.22-02-025 on December 28, 2022. A decision adopting some version of the procurement plans is expected before the end of 2023.

Renewable Hydrogen Injection Safety Pilot Projects

In December 2022, the CPUC issued D.22-12-057 ordering the gas IOUs to propose pilot projects studying the safety impacts of blending hydrogen into the methane pipeline system, with the hydrogen blend making up to 20 percent of the methane in the system. The decision ordered the gas IOUs to file an application proposing their pilots by December 2024. The decision also established an interim clean renewable hydrogen definition as emitting no more than 4 kilograms (kg) of carbon dioxide equivalent (CO2e) per kg of hydrogen produced on a life-cycle basis and not using fossil fuel as a feedstock or production energy source. That definition matches the definition for clean hydrogen eligible for federal production incentive payment as established in the Inflation

Reduction Act of 2022 while adding a "renewable" standard that is ultimately contingent on further deliberation through the SB 1075 (Skinner, 2022) implementation process in collaboration with CARB and the CEC.

Risk Spending Accountability Report (RSAR) Reviews

In December 2014, the CPUC issued D.14-12-025, which directed the IOUs under its jurisdiction to prepare annual reports comparing GRC-authorized and actual spending on risk mitigation projects and explain any discrepancies. In 2022, CPUC staff reviewed the Risk Spending Accountability Reports (RSARs) filed by the four largest IOUs (SCE, SDG&E, SoCalGas, and PG&E) and identified spending patterns of concern with respect to the provision of safe and reliable gas and electric service. The RSAR reviews provide stakeholders in the GRC process useful information regarding the IOUs' spending on major work categories for cost containment consideration in the next GRCs.

They also provide stakeholders with an opportunity to comment on the filing. a process which has yielded valuable input on the content and format of the filings.[297]

On October 6, 2022, the Commission passed D.22-10-002 in the Risk-based Decision-making Framework proceeding (RDF; R.20-07-013), which updated and clarified the report's requirements pertaining to the structure of the report, project status, calculation of authorized spending and variance explanations.

The report also simplified the filing dates for the reports. IOUs are now required to submit their RSARs by April 30 each year with intervenors supplying their comments by July 21st. CPUC Staff review the reports and issue observations and recommendations on October 31st.

Gas Line Extension Subsidy Phase-out in Phase III of Building Decarbonization Proceeding

In November 2021, CPUC's Energy Division staff released a report recommending the complete elimination of all gas line extension subsidies (i.e., allowances, refunds, and discounts) for all customer classes effective July 1, 2023. According to the staff report, gas ratepayers subsidize gas line extensions at a cost exceeding $100 million annually.[298] The report further states, "By eliminating all gas line extension allowances, builders would be forced to shoulder greater expense if they choose to construct a building that uses gas...the added up-front gas burden would send a signal to builders that building new gas infrastructure is more expensive, and thus make dual-fuel construction less desirable and financially riskier. As such, the builder community would be more likely to gravitate towards all-electric new construction."[299] The CPUC issued a Proposed Decision

[297] For more information on RSARs *see* https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/risk-spending-accountability-reports.
[298] R.19-01-011, ruling of November 16, 2021, pp. 21, 23.
[299] *Ibid*, p. 31.

recommending action consistent with staff's report on August 8, 2022, and approved a final decision (D.22-09-026) on September 15, 2022. While gas line extension subsidies will be eliminated effective July 1, 2023, the Commission made available a pathway for the IOUs to request special exemptions for cases in which a builder can demonstrate that receiving such a subsidy would further California's climate goals.

Non-CPUC Regulations that Impact Rates

CalGem Storage Regulations

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

There are significant costs associated with the work that the gas utilities must undertake to adhere to these regulations, including well construction requirements, additional inspections and surveys, biennial integrity testing, and continuous well monitoring. The projected costs for all gas storage providers would be significantly more under the default CalGEM rules, which require that all wells be tested every two years. Complying with the CalGEM rules also decreases storage injection and withdrawal capacity for two reasons: 1) wells are out of service during biennial testing; and 2) flowing gas only through a well's tubing reduces its injection and withdrawal capacity compared to flowing gas through the tubing and packer.

On June 15, 2021, CalGEM approved a modified version of PG&E's 2021 Revised Implementation Plan. Under PG&E's 2021 Revised Implementation Plan, its capital cost projections from 2022 through 2025 are estimated to be approximately $198 million. In addition, its Operations and Maintenance (O&M) cost projections for 2022 through 2030 are estimated to be approximately $139 million. In approving PG&E's 2021 Revised Implementation Plan, CalGEM required three additional well inspection and testing requirements to be met, which includes more frequent testing than proposed in PG&E's original plan. Due to the additional testing and inspection requirements, PG&E submitted testimony in its 2021 GRC (A.21-06-021) indicating that retaining the Los Medanos gas storage field, which was set to be decommissioned, would be the most cost-effective way to meet reliability standards, along with the drilling of new wells to offset withdrawal capacity losses from work that is required to meet the CalGEM requirements. Forecasted costs to retain Los Medanos are estimated to be approximately $109.5 million ($12.5M in 2022, $12.5M in 2023, $74.5M in 2024, and 10M in 2025), and $98 million for the drilling of new wells ($19M in 2023, $46M in 2024, and $33M in 2025). PG&E's testimony indicates that capital expenditure costs are forecasted to increase by 5 percent in 2023 and in 2024, and by 15 percent in 2025. O&M costs are forecasted to increase by 44 percent in 2023, 36 percent in 2024, 41 percent in 2025, and 24 percent in 2026.

SoCalGas' Risk Management Plan is currently pending approval. To date, CalGEM has approved a one-time extension of the wall-thickness inspection period for seven of SoCalGas' 105 active wells. However, the 24-month pressure testing cycle is still required for these wells, which reduces potential savings.

PHMSA Mega Rule

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is an agency within the U.S. Department of Transportation that oversees the nation's pipeline infrastructure. Two major gas pipeline incidents caused PHMSA to issue a Notice of Proposed Rulemaking in April 2016 to clarify and enhance rules for the safe transportation of gas and hazardous liquids. The 2010 San Bruno, California pipeline rupture revealed the dangers of "grandfather" clauses that did not require older transmission pipelines to meet modern testing standards.[300] The 2012 rupture of a pipeline near a highway in Sissonville, West Virginia demonstrated the limitations of the definition of High Consequence Areas (HCAs),[301] which did not include proximity to major roadways. PHMSA divided the rulemaking into three phases, with the first phase focused on the safety of gas transmission pipelines; the second on repair criteria in HCAs and non-HCAs, integrity management improvements, corrosion control, and other related issues; and the third on gas gathering lines. Together, these rulemakings are often referred to as the PHMSA Mega Rule.

The final rule in the first phase was issued on October 1, 2019. It mandates that gas operators begin implementing the new procedures on July 1, 2021. The primary requirements of the new rule are that pipeline operators must 1) reconfirm the maximum allowable operating pressure (MAOP) of certain transmission pipelines by 2035, 2) verify pipeline material properties and attributes, and 3) identify and conduct inline inspections of "piggable" transmission pipelines in Moderate Consequence Areas (MCAs) by 2034 and reassess them every 10 years thereafter.[302]

"Moderate Consequence Area" is a new definition created by the rule that applies to transmission lines operating at 30 percent Specified Minimum Yield Strength (SMYS) or higher that have a Potential Impact Circle that contains five or more buildings intended for human occupancy and/or

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

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

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

a principal roadway with four or more lanes. Previously, pipeline operators were only required to do inline inspections in High Consequence Areas.

Reconfirming MAOP

The Mega Rule states that MAOP must be reconfirmed for transmission lines in High Consequence Areas and Class 3 and 4 locations and piggable transmission lines in Moderate Consequence Areas that don't have verifiable records that they have met the modern standard.[303] Operators must reconfirm 50 percent of pipeline mileage by July 3, 2028, and 100 percent by July 2, 2035. The following methods can be used to reconfirm MAOP: pressure test; pressure reduction; Engineering Critical Assessment (ECA) using in-line inspection (ILI or pigging) tools; pipeline replacement; small Potential Impact Radius (PIR) pressure reduction; or other technology.

Verifying Pipeline Materials

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

Assessment Outside High Consequence Areas

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

Comparison of Mega Rule and PSEP

The Mega Rule and PSEP both have their origins in the San Bruno pipeline explosion and seek to improve transmission pipeline safety, but they are not identical. The Mega Rule will require California utilities to make additional expenditures on pipeline safety beyond what they have made, or planned to make, on PSEP. The table below provides a comparison of the two programs.

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

Table 22: Mega Rule vs. PSEP

	Mega Rule	PSEP
MAOP Reconfirmation Required	Transmission lines operating at 30% SMYS and above without verifiable records	All transmission lines without record of post-construction pressure test
MAOP Reconfirmation Methods Allowed	Various, listed above	Pressure test or replace
Verification of Pipeline Materials and Properties?	Yes	No
Assessment in MCAs?	Yes	No
Requires Installation of Automatic and/or Remote Shut-off Valves?	No[304]	Yes
Requires Replacement Pipeline to Be Piggable?	No	Yes

PG&E and SoCalGas/SDG&E provided initial estimates of the miles of pipeline that would be impacted by phase 1 of the Mega Rule to the CPUC's Safety and Enforcement Division (SED). These estimates are preliminary and subject to change.

Table 23: Miles of Pipeline Subject to PHMSA Mega Rule

	PG&E	SoCalGas/SDG&E
MAOP Reconfirmation	345	1,040
Materials Verification	210[305]	1,354
Assessment Outside HCA	873.5	253

Source: SED.

Track 2b of the Long-Term Gas Planning OIR, will examine ways to streamline the implementation of safety rules to save costs. While PG&E has mostly completed PSEP work, SoCalGas/SDG&E's PSEP work is ongoing. One potential cost-saving strategy would be to revise California's PSEP rules to allow for the additional MAOP reconfirmation strategies approved by PHMSA rather than requiring that all transmission pipelines be pressure tested or replaced. Mega Rule costs are embedded in the utilities' costs for their Transmission Integrity Management and Gas Safety Enhancement Programs.

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

[305] The Materials Verification miles overlap with some of the MAOP Reconfirmation miles.

CARB GHG Regulations

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

Following AB 32, CARB promulgated regulations creating the Cap-and-Trade Program. Under CARB's regulations, large emitters of greenhouse gases must purchase and surrender compliance instruments (typically allowances or offsets) to CARB for each ton of GHG released. This includes electric and natural gas utilities, who must pay for GHG emissions that come from burning fuel for electricity generation or that occur when customers burn purchased fuel. Electric utilities began accruing Cap-and-Trade Program costs January 1, 2013, while natural gas utilities began accruing costs January 1, 2015. However, Cap-and-Trade costs for natural gas utilities were not introduced into rates until July 1, 2018. For electric utilities, costs were not incorporated into electric rates until January 1, 2014.

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

CARB also allocates some allowances for free to electric and natural gas utilities on behalf of their ratepayers. Electric IOUs are required to sell these allowances at auction and utilize the proceeds for the benefit of ratepayers. Natural gas IOUs may also use some allowances for compliance, reducing the cost passed to customers in rates. Since 2014 (for electric customers) and 2018 (for most natural gas customers) residential customers have received the California Climate Credit as their share of the proceeds for the sale of allocated allowances. Although not part of rates, the California Climate Credit is delivered on-bill automatically to all residential ratepayers, including submetered customers and community choice aggregator (CCA) customers within the footprint of an IOU. Since 2014, as a result of the Cap-and-Trade Program, the average residential electric customer has received around $500 in California Climate Credits, while the average residential natural gas customer has received around $150.

Non-residential customers also pay Cap-and-Trade costs in rates. For electric customers, Public Utilities Cost Section 748.5 requires that small business and emission-intensive trade-exposed industrial customers also receive a portion of the CARB allocated allowance proceeds. Small Business customers automatically receive the on-bill Small Business California Climate Credit, while qualifying industrial customers receive the California Industry Assistance Credit. Since 2014, the assistance to small business customers has totaled $512 million while the California Industry Assistance Credit has totaled $588 million statewide. Natural gas non-residential customers do not receive on-bill assistance.

APPENDICES

Appendix A – 2022 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 2023 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 "2023 Electric and Gas Costs Utility Reports" bullet point under "Reports and White Papers" section of the webpage.

Appendix B - A Lexicon of Key Ratemaking Terms and Definitions

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

- **Attrition Year:** In GRC proceedings, a year subsequent to the test year for which formulaic adjustments to the test year revenue requirement are made until the next GRC cycle commences.
- **Bundled Customers:** Customers who get all of their services - generation, transmission, and distribution services - from the Investor-Owned Utilities.
- **Bundled System Average Rate (Bundled SAR):** Bundled authorized revenue requirement divided by bundled forecasted kilowatt-hour sales.
- **Bundled Residential Average Rate (Bundled RAR):** Bundled residential class authorized revenue requirement divided by bundled residential forecasted kilowatt-hour sales.
- **Cost of Service Regulation (COSR):** 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.
- **Distributed Energy Resources (DER):** Distribution-connected generation resources, including energy efficiency, storage, electric vehicles, and demand response technologies.
- **Energy Burden:** Actual home energy costs as a percentage of household income.

- **Energy Resource Recovery Account (ERRA):** ERRA balancing accounts are evaluated in annual proceedings and track authorized versus actual utility energy procurement costs e.g., fuel and purchased power. ERRA costs are pass-through expenses; the utility receives no mark up or profit on these costs.

- **Fixed Charge:** A charge assessed on customer bills to recover fixed costs.

- **Fixed Cost:** A cost that does not change as the quantity consumed (and produced) changes during some defined time increment. A utility's fixed costs may be difficult to allocate because some costs are customer-specific and some are systemwide.

- **General Rate Case (GRC):** A proceeding in which revenue requirements are approved based on the costs of operating and maintaining the utility system. GRCs are often "settled" based on overall agreement between advocacy groups and the utility, with the CPUC approving the settlement agreement if it is "reasonable in light of the whole record, consistent with the law, and in the public interest…"

- **Grid Services:** The utility's cost of providing grid services consists of at least four components — the typical fixed costs associated with: (1) transmission, (2) distribution, (3) generation capacity and (4) ancillary and balancing services that the grid provides throughout the day.

- **Load Serving Entities (LSE):** A company or organization that supplies load (electricity) to customers. For CPUC-jurisdictional LSEs, these are defined as Investor-Owned Utilities (IOU), Community Choice Aggregators (CCA) and Direct Access (DA) suppliers.

- **Non-Bypassable Charges (NBC):** Costs of public purpose programs (PPP) and certain other programs or costs that are paid by all customers who use the utility delivery system.

- **Non-Rate Base Expenses:** Costs that the utility collects from customers but does not place in rate base and for which it does not earn a profit. This includes pass-through costs for non-utility owned generation and fuel costs.

- **Non-Wires Alternatives (NWA):** Non-traditional solutions, such as DERs, which replace traditional transmission and distribution investments, such as poles, wires, and transformers.

- **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 of Return (ROR) on Rate Base:** The cost of paying back utility debtholders with interest, plus the Return on Equity (ROE) to shareholders, as a weighted average of all types of capital.

- **Return on Equity (ROE):** Return to utility shareholders, or profit, and the most controversial component of the ROR formula.

- **Rate Design:** Designing rate schedules and further allocating revenues to individual customers within a customer class. Rate design is also used to promote conservation or other desired outcomes.

- **Revenue Requirement or Utility Costs:** Total operating costs, depreciation, and a reasonable profit, as recovered in rates.

- **Revenue Allocation:** Allocating total revenue requirement to individual customer classes (residential, commercial, agricultural, industrial) based on the utility's cost to serve that class.

- **Test Year:** In GRC proceedings, the first year of the GRC cycle for which the CPUC sets a pre-specified revenue requirement.

- **Time-of-Use (TOU) Rate Plan**: TOU rate plans are based on when and how much energy is used. TOU rates are lower during the day, when less expensive renewable energy sources like solar and wind are available.

- **Total Revenue Requirement:** Rate Base x Authorized Rate of Return + Expenses.

- **Total System Average Rate:** Total authorized revenue requirement divided by total forecasted kilowatt-hour sales.

- **Unbundled Customers**: Customers who take distribution and transmission service only, with generation service provided by a separate entity, usually a Community Choice Aggregator (CCA) or Direct Access (DA) service provider.

- **Utility Decoupling:** Decoupling refers to annual rate-making adjustments that ensure that utility earnings are separate and independent of actual kWh sales between rate cases, thus removing the disincentive for utilities to encourage energy conservation.