2022 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

PUBLISHED MAY 2022

California Public Utilities Commission

2022 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

Contributors:
Bridget Sieren-Smith
Paul S. Phillips
Gelila Berhane
Elizabeth La Cour
Jean Spencer
Nick Zanjani

Special thanks to:
Kristina Abadjian, Love Asiedu-Akrofi, Amardeep Assar, Adam Banasiak, Jack Chang, Michael Conklin, Rory Cox, Julia Ende, Kevin Flaherty, Renee Guild, Tory Francisco, Eileen Hlavka, Ankit Jain, Alison LaBonte, Richard Myers, Andrew Ngo, Danny Nguyen, Erica Petrofsky, Karin Sung, Jason Symonds, Michael Truax, Carlos Velasquez, Abhilasha Wadhwa, Christopher Westling, David Zizmor

Table of Contents

List of Figures

List of Tables

I. Executive Summary

The California Public Utilities Commission (CPUC) issues this 2022 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 utility cost and rate increases consistent with the state's energy and environmental goals. California's Investor-Owned Utilities (IOU) are also required by statute to study and report to the CPUC recommended measures to limit costs and rate increases.[1]

For the 2022 SB 695 Report, two areas of increasing cost pressure are front and center: growing transmission and distribution infrastructure and operations costs, including wildfire mitigation costs, and equitable recovery of utility fixed costs.

As in last year's report, transmission and distribution infrastructure investments and operations are major cost drivers that continue to comprise a significant portion of IOU costs and rates.[2] While IOU capital expenditures (generally known as "rate base") are necessary to meet California's policy goals, investments in a safer, cleaner, and more efficient grid are increasing affordability challenges as IOU rate base continues rapidly trending upward.

Over the next several years it is anticipated that there will be higher than historic annual average growth rates for transmission and distribution infrastructure to account for climate change-driven investments, and most notably wildfire mitigation costs. In 2021, significant wildfire-related operating expenses, including wildfire liability insurance coverage, began to appear in rates and all indicators point to continued significant rate growth in the near term resulting from these ongoing wildfire mitigation efforts.

While increasing transmission and distribution costs continue to drive total system costs higher, the rate designs used to recover system costs have important effects on equity and clean energy adoption. The majority of the utilities' revenue requirement, including funds for generation, transmission and distribution investments, and operations and maintenance work, is recovered from customers via a volumetric rate.[3] However, only a portion of the IOUs' costs (principally generation

---

[1] *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.

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

[3] Volumetric rates collect revenues from customers on a cents/kilowatt-hour basis such that a customer's bill varies based on how much energy the customer consumes.

and some distribution costs) directly vary based on how much energy a customer consumes, while many infrastructure and operational costs (referred to as "fixed" costs)[4] do not.

Under this ratemaking structure, declines in electricity sales (due to, for example, greater adoption of distributed energy resources (DER) such as rooftop solar or energy efficiency) lead to a situation in which electric rates must rise to recover sufficient revenue to support certain fixed utility costs. While some stakeholders have proposed remedying this rate impact by authorizing the IOUs to increase the fixed charge component of customer rates to recover a greater proportion of fixed costs, this would require a statutory change beyond current limits.[5] Stakeholders have also proposed that fixed charges be collected on an income-graduated basis to ensure that the burden of supporting the electric grid and achieving California's climate change goals is shared equitably.

The disparity between volumetric revenue recovery and fixed costs that do not vary with energy consumption also contributes to potential inequities among customers. Customers with DERs on a net energy metering (NEM) tariff, such as residential rooftop solar customers, are compensated for the energy they generate and supply to the grid at full retail volumetric rates. Because many of the costs recovered in volumetric rates are fixed costs that do not vary with energy usage, compensating NEM customers for their generation at volumetric rates means that utilities recover a disproportionately small share of fixed costs from NEM customers. In order to recover the full authorized revenue requirement, retail volumetric rates must rise, disproportionately burdening non-participating customers, who on average have lower incomes than NEM customers. This is referred to as the "cost shift."[6] The CPUC is currently considering proposals to modernize NEM.[7]

In addition to transmission and distribution infrastructure and operations costs and equitable recovery of utility fixed costs, this report includes discussion of other recommendations that can be undertaken over the succeeding 12 months to limit utility cost and rate increases. These recommendations were presented as part of the 2022 Affordability En Banc (En Banc) hearing held

---

4 Fixed costs are costs that generally do not vary based on how much electricity a customer uses. Costs such as operations and maintenance and investments in transmission and distribution lines, poles, substations, transformers meters and maintenance of buildings are considered fixed costs because those costs tend to not change regardless of how much electricity customers use.

5 Public Utilities Code §739.9(f) caps fixed charges at $10 per residential customer per month and $5 per residential customer per month for low-income customers that qualify for California Alternate Rates for Energy (CARE).

6 Decision (D.) 16-01-044, p. 81 further explains the cost shift: "The IOUs lose revenue from NEM customers, particularly residential NEM customers, because those customers pay less to cover fixed costs through their volumetric rates. This revenue is recovered through increases in rates paid by all customers. This circumstance is often referred to as a "cost shift" from NEM customers to other customers, who pay the increase in rates but without receiving any of the specific benefits, such as credit for exports, that accrue to NEM customers." *See* "Net Energy Metering Tariffs Cost Considerations" section later in this report.

7 A proposed decision (PD) to modernize NEM was issued on December 13, 2021. One objective of the PD, among many, is to reduce the cost shift and further align with statutory requirements to ensure the tariff's benefits to all customers and the electrical system approximately equal its costs and that behind-the-meter distributed generation continues to grow sustainably.

on February 28, 2022 and March 1, 2022. The En Banc included detailed stakeholder proposals[8] on actions that could be undertaken to reduce utility costs and revenue requirements as well as proposals to recover costs consistent with affordability, equity, and clean energy goals.

The operational landscape facing the IOUs has changed drastically in the last few years. The need for additional critical measures to protect customers from catastrophic wildfires, growing pressure on rates resulting from the current NEM tariff, and difficult economic conditions resulting in part from the COVID-19 pandemic have resulted in rising costs that are challenging to mitigate. Indeed, rate relief for customers may need to come from outside of the CPUC's current framework of cost allocation and rate design, as lawmakers and CPUC decision-makers consider utility operational areas and public purpose programs that may be more appropriately funded by all Californians.

California Utilities Compared to the Rest of the U.S.

In advancing clean energy policy in the United States, California leadership must be considered in the context of both past and future rates and bill trends:

- The state's per capita energy consumption is one of the lowest in the nation, due in part to California's mild climate as well as the state's commitment to energy efficiency.[9]

- California ranks first in the nation as a producer of electricity from solar, geothermal, and biomass resources and second in the nation in conventional hydroelectric power generation.[10]

- California was set to finish 2021 with approximately 2,500 MW of battery storage installed on the Independent System Operator (ISO) grid, up from about 250 MW in summer 2020. This is the highest concentration of lithium-ion battery storage in the world.[11]

- About 30 percent of the nation's public electric vehicle charging stations are in California.[12]

Many of these efforts have resulted in a cleaner electricity portfolio but have also led to declines in electricity sales due to customer generation, energy efficiency, and conservation of electricity. Declining sales lead to rising electric rates as fixed costs are spread over a smaller usage base. At the same time, costs for various state-mandated programs intended to *increase* low-carbon electricity consumption, such as funding electric vehicle infrastructure as a strategy for substantially reducing

---

[8] *See* 2-28-22 Hearing and 3-1-22 Hearing.

[9] *See* U.S. Energy Information Administration (EIA) https://www.eia.gov/todayinenergy/detail.php?id=49036#.

[10] *Ibid.* https://www.eia.gov/state/analysis.php?sid=CA.

[11] *See* California Independent System Operator (CAISO) http://www.caiso.com/Documents/CEO-Report-Dec-2021.pdf.

[12] U.S. Department of Energy, Energy Efficiency and Renewable Energy, Alternative Fuels Data Center, Electric Vehicle Charging Station Locations, California and U.S., Electric-All, Public.

statewide greenhouse gas emissions, also may raise electricity rates in the short term.[13] The cost implications and trade-offs of energy policy choices facing decision-makers and the rising costs of providing Californians access to safe, reliable, clean, and affordable utility service and infrastructure, underscore the need for improved tools that forecast the rate impacts of both utility operations and policy choices.

In keeping with past SB 695 Reports, rates and bills for bundled[14] residential customers are highlighted. Historically, the bundled Residential Average Rates (RAR) of the California IOUs have been higher than those of most United States IOUs.[15] Table 1 shows the simple volumetric bundled RAR for PG&E, SCE, and SDG&E from 2018 to 2020[16] compared to approximately 200 total IOUs nationally, ranked from highest rates (#1 ranking) to lowest rates (#200 ranking).[17] For example, in 2020 SDG&E's bundled RAR ranked 9th highest.

While rates are an important measure of the cost of providing electricity, looking at actual bills provides a clearer picture of affordability. From 2018 to 2020, Table 1 shows California IOU bundled residential customer bills have been quickly trending upward relative to the bills of approximately 200 total IOUs nationally. For example, in 2018, SDG&E's bundled residential average monthly bill ranked 108th highest out of about 200 IOUs. However, in 2020, SDG&E's bundled residential average monthly bill ranked 87th highest. PG&E and SCE's bundled residential average monthly bills show similar higher trends, with bundled residential average monthly bills ranked the 25th and 85th highest in 2020, respectively.

---

13 In the medium- and long-term, increasing electric sales due to building and vehicle electrification should have a moderating impact on rates as the recovery of certain utility fixed costs is spread over more kilowatt hours of sales.

14 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.

15 "Higher than most" is the same as "higher than the median," or "higher than half of the items being ranked." In other words, because the ranking is from highest rate to lowest rate, the lower the ranking number, the higher the rate.

16 2020 is the most recent year for which national-level data is available. *See* U.S. Energy Information Administration (U.S. EIA) https://www.eia.gov/electricity/sales_revenue_price/, Table 6.

17 2020 data in red font indicate a negative trend (i.e., higher rate or higher bill) over 2019 data.

Table 1: U.S. IOU Ranking of PG&E, SCE, and SDG&E, Bundled Residential Average Rates and Monthly Bills (2018 - 2020)

	U.S. IOU Ranking - Highest to Lowest (out of approximately 200 IOUs)					
	Bundled Residential Average Rate			Bundled Residential Average Monthly Bill		
IOU	**2018**	**2019**	**2020**	**2018**	**2019**	**2020**
PG&E	15	24	13	94	70	25
SCE	31	42	21	136	142	85
SDG&E	9	17	9	108	122	87

Key Findings

Across all three IOUs since 2013,[18] bundled residential average rates have increased at an annual average rate of about 7 percent for PG&E, 5 percent for SCE, and 10 percent for SDG&E. Starting in 2021, costs related to both operational practices and infrastructure investment to improve wildfire safety have begun to appear in rates in significant amounts. For PG&E and SCE, revenue requirements for distribution and transmission operating expense, including operations and maintenance (O&M) expense, have been increasing at an annual average rate greater than inflation. The primary driver of these O&M costs is wildfire mitigation work, including enhanced inspections and vegetation management efforts. PG&E, SCE, and SDG&E distribution and transmission rate base has also risen sharply in recent years[19] despite flat to declining load growth over this same period, primarily reflecting hardening of the grid against wildfire. All indicators point to continued significant rate growth in the near term from wildfire mitigation efforts.

Looking forward, the bundled RAR forecasts indicate steady growth in customer rates (nominal $/kilowatt-hour (kWh)) between the first quarter of 2022 and fourth quarter of 2025 for the three IOUs.[20]

- PG&E: 26 percent through 2025 or an annual average of 6.8 percent over this period
- SCE: 16 percent through 2025 or an annual average of 4.2 percent over this period

---

[18] Prior to 2013, the total system average rate (i.e., all rate classes) of each of the IOUs roughly tracked inflation; *See* the 2021 Assembly Bill (AB) 67 Report. Rate increases calculated from January 1, 2013 to January 1, 2022.

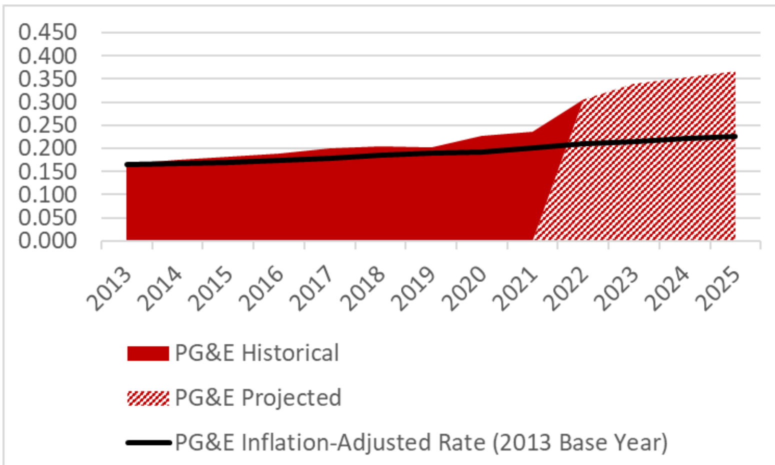
[19] Rate base generally increases when net capital additions outpace accumulated depreciation of the rate base assets.

[20] Actual rates in effect at end of first quarter of 2022, with 3.75 years remaining through year-end 2025. Forecasts do not take into account future natural gas price spikes, which are difficult to predict.

- SDG&E: 24 percent through 2025 or an annual average of 6.4 percent over this period

Figure 1 through Figure 3 show that by 2025, bundled RARs are forecast to be approximately 60 percent (PG&E), 25 percent (SCE), and 70 percent (SDG&E) higher than they would have been if 2013 rates for each IOU had grown at the rate of inflation.[21]

Figure 1: PG&E Bundled Residential Average Rates, Nominal Historical and Projected with Inflation-Adjusted Comparison ($/kWh)



[21] Annual average inflation rate 2023 – 2025 forecasted at 2.4 percent. Projected rate inflators from U.S. Congressional Budget Office's "Update to the Budget and Economic Outlook: 2021 to 2031" (July 2021, p. 4), consumer price index for all urban consumers.

Figure 2: SCE Bundled Residential Average Rates, Nominal Historical and Projected with Inflation-Adjusted Comparison ($/kWh)

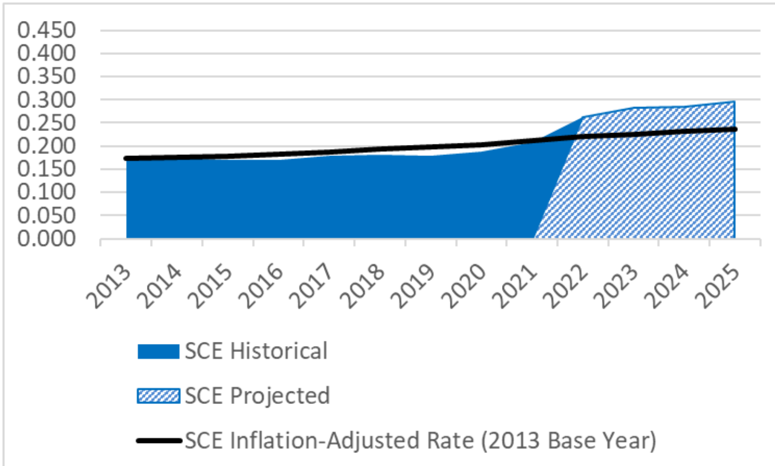


Figure 3: SDG&E Bundled Residential Average Rates, Nominal Historical and Projected with Inflation-Adjusted Comparison ($/kWh)

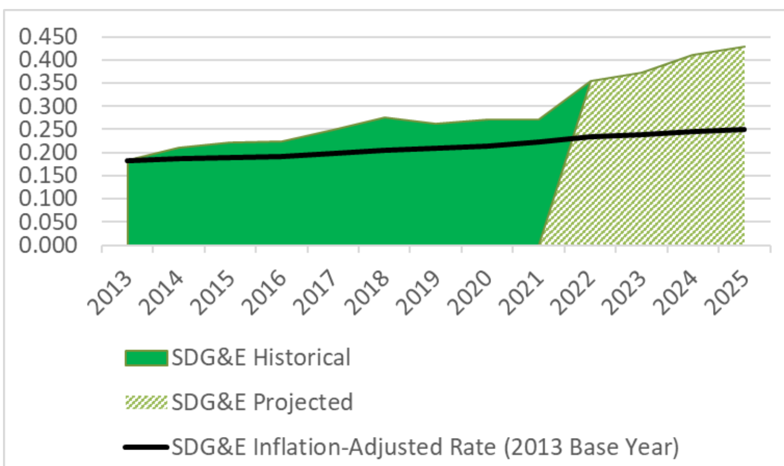


Table 2 shows the projected monthly bill increase resulting from the rates forecasts in Figure 1 through Figure 3 based on the usage amounts the IOUs use in their legal bill inserts – 500 kWh per month for PG&E and SCE, and 425 kWh for SDG&E.[22]

Table 2: Current and Projected 2025 Bills

IOU	Current Residential Average Monthly Bill	Projected 2025 Average Monthly Bill	Projected 2025 Annual Average Increase
PG&E	$165	$211	9.2%
SCE	$150	$168	4.0%
SDG&E	$171	$213	8.2%

The aggregated nature of average bill data can mask affordability concerns for customers in the hotter regions of the state, and the CPUC is now tracking this disparity with more refined and granular tools for assessing affordability. High energy usage and bills in areas of California such as the Central Valley, San Joaquin Valley, and Coachella Valley (mainly due to air conditioning load) continue to be a concern. For example, due to climate change, many areas of the San Joaquin Valley are expected to see more than 1,000 additional cooling degree days (estimated energy demand needed to cool a building) by midcentury (2035-2064) compared to 1961-1990.[23] Customers in these areas of high electricity usage pay bills that reflect wildfire mitigation and insurance premium costs that are proportionally higher than for customers in areas of lesser usage[24] and which may also not be representative of local wildfire prevention costs and risk conditions. Apart from these considerations, integration of low-income and middle-income customers in these areas into the clean energy transition, including well-managed electrification, will be especially challenging.[25]

Over the past few years, there has been a growing divide between customers participating in behind-the-meter (BTM) or distributed energy resources (DER) and those who are less likely to do so. Moderate- to higher-income customers are more likely to invest in DERs such as solar photovoltaic (PV) systems, electric vehicles (EV), and energy storage technologies, and utilize the advanced rate offerings that support them. Without the prudent management of IOU revenue requirements, rate base, rate structures, and DER incentives, California's continued progress toward greater

---

[22] Usage data here is that used in legal bill inserts for PG&E's 2023 General Rate Case (GRC) Phase I, SCE's 2021 GRC Phase II, and SDG&E's 2022 Energy Resource Recovery Account Forecast applications, for climate zones X, 9, and Inland, respectively. Bills are for illustrative purposes only.

[23] If the average temperature is 10 degrees above 65 degrees for one day in a year, there are 10 cooling degree days for that year for that location. *See* California Energy Commission's "Energy Equity Indicators Tracking Progress Report."

[24] As these costs are recouped in volumetric rates i.e., $/kWh, the higher the usage, the higher a customer's bill.

[25] Well-managed electrification, in this case, means rate incentives for fuel substitution of buildings and vehicles, and load shifting to lower-cost periods.

electrification and a more efficient grid the optimized grid of the future may widen this chasm could lead to greater inequities between participants and non-participants in DER opportunities.[26]

Three critical and overlapping policy fronts must be actively managed to address the risk that high electric rates and bills could slow California's overall progress towards its electrification and climate goals, and harm some of the state's most economically vulnerable residents:

1. The relatively rapid pace of rate base growth and wildfire-related operating expense, including enhanced inspections and vegetation management efforts and liability insurance.

2. The need to ensure that low-income and middle-income customers can benefit from clean energy and electrification policies.

3. The need to mitigate cost shifts to low-income and middle-income non-participants from Net Energy Metering (NEM) and other DER incentives.

Between now and 2025, average electric bills are forecast to rise at an annual average rate of 9 percent for PG&E customers, about 4 percent for SCE customers, and about 8 percent for SDG&E customers, implying that these households' electric bill will become less affordable if household incomes track the assumed inflation rate of 2.4 percent.

The CPUC opened an Affordability proceeding[27] in 2018 to address these growing concerns. Thus far, the CPUC has adopted metrics and forecasting tools for assessing the affordability of combined essential utility services (electricity, gas, water, and communications) by location in California, which are "first-of-its-kind" in the nation. The CPUC held an En Banc hearing in February 2021 to sharpen attention on affordability issues, the results of which are memorialized in the 2021 SB 695 Report.[28] Then, on February 28 and March 1, 2022, the CPUC held another En Banc hearing to deepen its review of stakeholder proposals and introduce new potential options to mitigate energy rate and bill increases.[29]

---

26 A deeper examination is required of the long-term savings and benefits to the system of a more efficient grid with greater penetration of BTM resources.

27 *See* docket for Rulemaking (R.)18-07-006.

28 *See* 2021 SB 695 Report.

29 *See* 2-28-22 Hearing and 3-1-22 Hearing.

A recent analysis using CPUC-developed metrics indicates that there are significant disparities across the state in terms of low-income households' ability to pay for utility services. The analysis found that there are specific geographic areas within the state where affordability concerns are most acute, including Oakland, Stockton, Fresno, Modesto, Tulare County, Bakersfield, San Bernardino, and many parts of Los Angeles.[30]

These observed disparities may be exacerbated in the coming years as the impacts of the COVID-19 pandemic and accompanying economic impacts unfold. Preliminary economic data indicates that prior disparities have likely worsened over the past two years. Further, the 2021–2022 global energy crisis, driven by a surge in demand as the world exited the early recession caused by the pandemic, will continue to unfold, with unknown economic consequences for ratepayers.

For natural gas, in 2022 utility revenue requirements increased for PG&E by 20 percent, SDG&E by 16 percent, and Southern California Gas Company (SoCalGas) by 16 percent, over 2021 utility revenue requirements. The principal reasons for the increases are from costs primarily associated with safety related programs, including new regulations, to maintain or enhance the safety of gas pipelines and storage facilities. The CPUC takes actions to limit utility costs and rate increases by scrutinizing the utilities' natural gas revenue requests in CPUC proceedings.[31]

Organization

The remainder of this report is organized as follows:

- **Chapter II**: 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. In addition, this chapter summarizes proposals from stakeholders to limit future electric cost, rate, and bill increases.

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

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

- **Chapter V:** Information provided by the IOUs to fulfill the requirements of Public Utilities Code Section 913.1(b).

---

30 *See* 2019 Annual Affordability Report.

31 *See* Chapter IV, section "Costs and Rates Containment."

II. 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 earn a reasonable profit, while ensuring that rates are just and reasonable. The cost-of-service regulatory model aims to provide universal safe and reliable electricity while ensuring monopoly 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 of these costs in various rate-making proceedings. Utility costs, other than the cost of procuring fuel and purchased power,[32] are generally addressed in General Rate Case (GRC) proceedings.[33] In these 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.

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.

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 (PPPs) 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 after cost recovery is approved in ratemaking proceedings. The CPUC authorizes this cost recovery by one or

[32] 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.

[33] For more detailed descriptions of how GRC proceedings and Energy Resource Recovery Account (ERRA) proceedings authorize utility revenue requirements *see* the 2021 AB 67 Report.

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 which include the cost of Utility Owned Generation (UOG), consisting of fuel, 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[34] is also reflected in generation rates.

The **distribution rate component** collects the revenue requirement corresponding to distribution 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 bulk transmission lines owned by the utilities. Transmission rates are set by the Federal Energy Regulatory Commission (FERC). This rate component is comprised of four sub-components: 1) Base Transmission, which recovers the costs associated with transmission assets under ISO operational control and subject to FERC's jurisdiction; 2) transmission revenues, which flow to customers, generated through 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 which reflects the net contribution by IOU customers to the transmission revenue requirements of all participating transmission.

Other rate components are:

- Public Purpose Programs (PPP),
- New System Generation (NSG),
- Competition Transition Charge (CTC)
- Nuclear Decommissioning (ND),
- Wildfire Fund Non-Bypassable Charge (Wildfire Fund NBC), and

---

[34] 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 customer bills twice per year.

- Total Rate Adjustment Component (TRAC).

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 in order to maintain system reliability. CTC charges recover above-market costs associated with power purchase contract obligations that resulted from electric industry restructuring pursuant to Public Utilities Code Section 367(a). Nuclear decommissioning 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. The Wildfire Fund NBC rate component reflects ratepayer funding of the wildfire fund created by Assembly Bill (AB) 1054 (Holden, 2019)[35] starting in October 2020.[36] The Total Rate Adjustment Component (TRAC) rate component reflects the cost shift that resulted from capped residential tiered rates previously legislated under Assembly Bill 1X and Senate Bill 695.[37]

Balancing Accounts and Memorandum Accounts

Authorized revenue requirements also include balances recorded in balancing account and memorandum (memo) accounts. A balancing account is an account established to record certain authorized amounts for recovery through rates and to ensure the revenue collected matches the authorized amounts. Balancing accounts balances are to be returned to ratepayers if the account is over-collected, or additional revenue is to be recovered from ratepayers if the account is under-collected. Memo accounts are similar to balancing accounts except they record costs not yet authorized and are subject to further scrutiny by the CPUC. Expenses accrued in memo accounts may or may not be recoverable through rates.

Residential Uncollectible Balancing Account

On January 1, 2022, the IOUs began collecting in electric rates Residential Uncollectible Balancing Accounts (RUBA) balances corresponding to large pending, COVID-19 pandemic-related residential uncollectible customer account balances that were not in rates in 2021. These balances were offset, or are to be offset, with amounts from the California Arrearage Payment Program (CAPP), a state program created by Governor Gavin Newsom and the California Legislature to

---

35 AB 1054 also permitted certain wildfire capital costs to be securitized through a CPUC financing order rather than being financed through the more traditional unsecured bond offerings. PG&E and SCE currently have AB 1054 securitizations that are recovered through a non-bypassable fixed recovery charge.

36 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.

37 Applies to SDG&E only. The TRAC revenue requirement reflects an under-collection due to a timing issue resulting from cost shifts not yet fully recovered.

reduce energy utility customers' past due bills that increased during the COVID-19 pandemic.[38] The IOUs collectively placed about $225 million in non-generation-related RUBA balances into electric rates on January 1, 2022.[39] An estimated CAPP funding offset was applied to rates effective January 1, 2022 by SCE.[40]

January 1 Authorized Revenue Requirement

Figure 4 through Figure 6 reflect the authorized revenue requirements by rate component on January 1 of each year for each large electric IOU.[41]

---

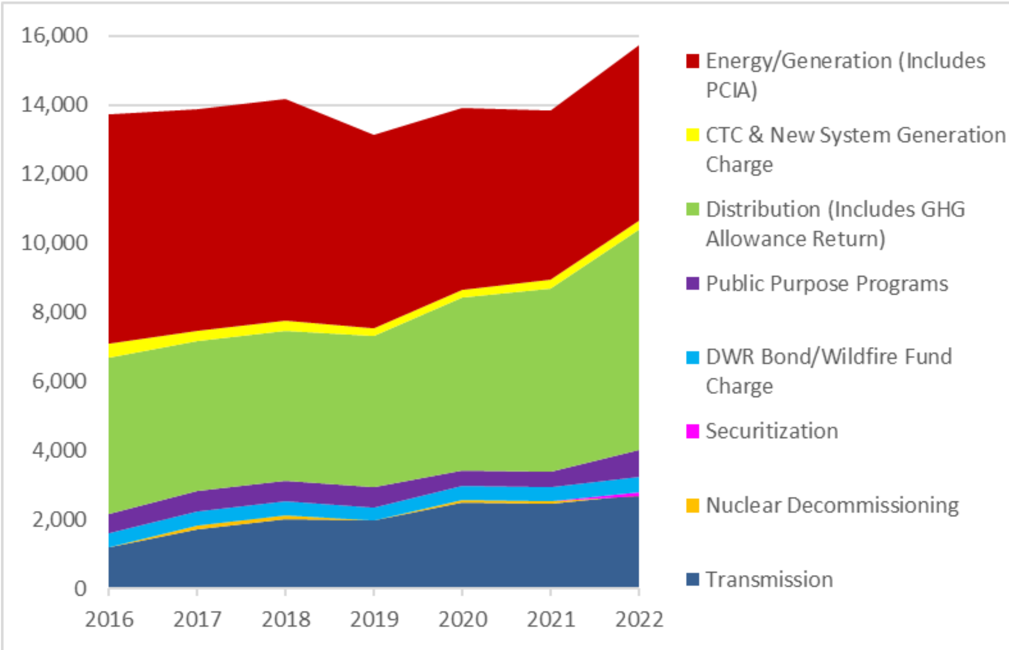
38 There is not a 1:1 relationship between total CAPP funding and reductions to RUBA. CAPP funding is applied to arrearages, which then indirectly impacts the RUBA due to an adjustment in the estimated bad debt expense.

39 PG&E $173.8 million with no estimated CAPP offset; SCE net $48.0 million based on a gross of $178 million less estimated CAPP offset of $54 million and an exclusion of $76 million associated with 2020 incremental uncollectibles; SDG&E $3.5 million with no estimated CAPP offset.

40 SCE applied a forecast of the impact of CAPP payments on its recorded bad-debt expense in its January 1, 2022 rate levels since actual funding was not received until January 2022; differences in the forecast versus actual amounts will be trued up as part of the 2022 year-end consolidated advice letter and put into rate levels in first quarter 2023.

41 Data from year 2016 was first introduced in the 2019 SB 695 Report and has been continually updated since that time. For data prior to year 2016, see the AB 67 reports here. Year-over-year revenue requirement changes by rate component category of 10 percent or greater are explained in greater detail. Revenue requirement does not capture programs that result in a cost shift or cross-subsidy between various customers groups. This includes, but is not limited to, programs such as Net Energy Metering, California Alternate Rates for Energy, the FERA Program (Family Electric Rate Assistance), and the Medical Baseline Program. Revenue requirements include netting effect of the semi-annual Greenhouse Gas Allowance Return credited to eligible customers through the distribution rate component. All dollars are nominal i.e., not adjusted for inflation unless otherwise indicated.

Figure 4: PG&E January 1 Revenue Requirement by Rate Component Category[42] ($ millions)



PG&E's revenue requirement corresponding to costs recovered in its generation rate component has been decreasing since 2016, while costs recovered in the distribution rate component were generally flat over the period 2016 – 2019, but increased over the period 2020 - 2022, and costs recovered in the transmission rate component have sharply increased over the period 2016 - 2022.[43]

The primary drivers of **the 21 percent increase in the distribution revenue requirement** from 2021 to 2022 are: (1) implementation of the 2020 GRC, including incremental insurance and vegetation management and insurance costs;[44] and (2) Wildfire Expense Memorandum Account (WEMA) costs reflecting excess costs associated with wildfire-related liabilities, including incremental insurance premiums.

The primary drivers of the **77 percent increase in PPP revenue requirement** from 2021 to 2022 are: (1) the recovery of the RUBA balance which is a new account in rates in 2022; and (2) an

42 PG&E's "Distribution (Includes GHG Allowance Returns)" and "Public Purpose Programs" in Figure 4 were restated in 2022 for all years shown to not net the CARE line item discount revenue shift.

43 PG&E's 2022 Energy Resource Recovery Account (ERRA) Forecast application was pending authorization on January 1, 2022 and is not included for 2022.

44 PG&E's 2020 GRC implemented March 2021 and is not reflected in the January 2021 revenue requirement.

increase in funding for the AB 841 School Energy Efficiency Stimulus (SEES) Program.[45] It is important to note that while the PPP revenue requirement has increased by 77 percent, PPP only makes up about 5 percent of the total revenue requirement on January 1, 2022, up from about 3 percent of the total revenue requirement on January 1, 2021.

The primary driver of the **10 percent increase in transmission revenue requirement**[46] from 2021 to 2022 is implementation of the Transmission Owner (TO) Formula Annual Update for Rate Year (RY) 2022, partially offset by a decrease in the Transmission Access Charge Balancing Account Adjustment (TACBAA). The most significant drivers of the changes in base transmission revenues are: (1) an increase in Operations and Maintenance (O&M) expenses,[47] including increases related to wildfire work and COVID-related costs for grid operations; and (2) an increase in Administrative and General (A&G) expenses largely associated with costs incurred for general liability insurance, Injuries and Damages, salaries, property insurance, and other A&G items. Other components contributing to the increase include recoveries of abandoned plant and depreciation expenses due to increased investments in capital expenditures.

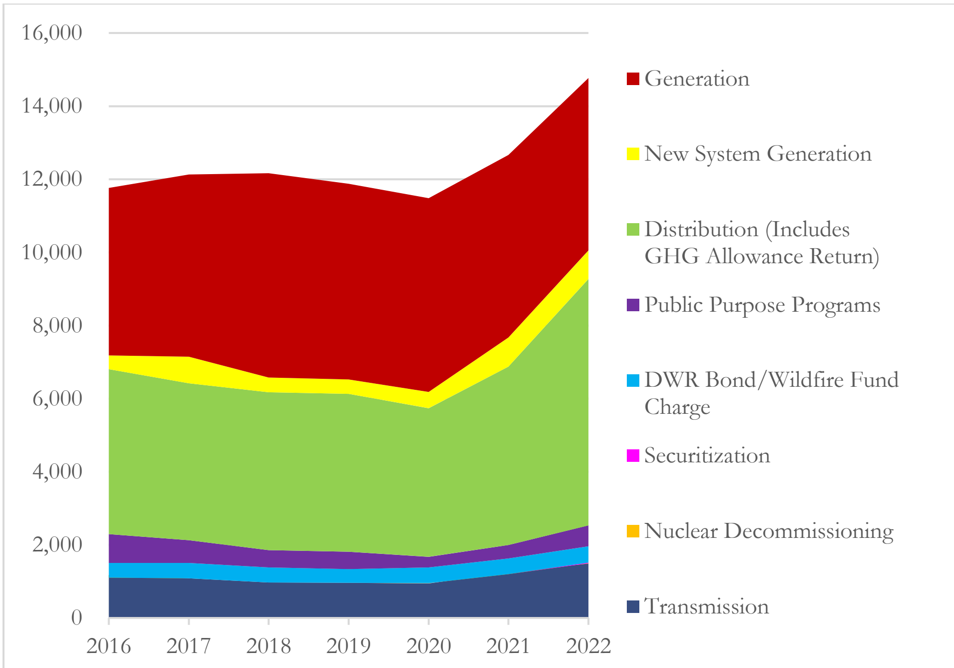
---

45 AB 841 (Ting, 2020) authorized the SEES program, which utilizes unspent funds from IOU Energy Efficiency rolling portfolio budgets for grants to schools for certain improvement projects. In the absence of the SEES program, these funds would be used to offset future collections to fund energy efficiency programs.

46 Includes Base Transmission, Transmission Revenue Balancing Account Adjustment (TRBAA), Reliability Services Balancing Account (RSBA), End-Use Customer Refund Account (ECRBA) and Transmission Access Charge Balancing Account Adjustment (TACBAA).

47 O&M includes all labor and non-labor expenses for a utility's operation and maintenance of its generation plants and distribution and transmission systems.

Figure 5: SCE January 1 Revenue Requirement by Rate Component Category[48]
($ millions)



The revenue requirement corresponding to costs recovered in SCE's generation rate component has been generally flat when comparing 2016 to 2022, while costs recovered in the distribution and transmission rate components had been trending downward from 2016 to 2020 before increasing sharply from 2021 to 2022.

The primary driver of the **38 percent increase in the distribution revenue requirement** from 2021 to 2022 is the implementation of Attrition Year 2022 adjustments (escalation factors prescribed in the 2021 GRC), including: (1) wildfire mitigation costs (increased capital for covered conductor and expenses driven by wildfire insurance premiums and wildfire vegetation management), as well as (2) infrastructure to support clean energy initiatives such as transportation electrification.[49]

---

[48] SCE did not implement its annual January 1, 2021 consolidated filing until February 1, 2021. As such, the 2021 revenues presented are the revenues in effect January 1, 2021 per AL 4301-E-A (rates effective October 1, 2020). In addition, SCE's 2022 Energy Resource Recovery Account (ERRA) Forecast applications was pending authorization on January 1, 2022 and is not included for 2022.

[49] Clean Energy Initiatives include transportation electrification, energy efficiency, demand response, and distributed generation.

The primary drivers of the **53 percent increase in PPP revenue requirement** from 2021 to 2022 are:[50] (1) an increase in Energy Efficiency program budgets; and (2) an increase in funding for the AB 841 School Energy Efficiency Stimulus (SEES) Program.[51] It is important to note that while the PPP revenue requirement has increased by 53 percent, PPP only makes up about 4 percent of the total revenue requirement on January 1, 2022, up from about 3 percent of the total revenue requirement on January 1, 2021.

The primary drivers of the **20 percent increase in transmission revenue requirement**[52] from 2021 to 2022 are: (1) increased plant in service that has been added to rate base (completion of large projects such as the West of Devers Upgrade); (2) the formula rate that reflects the portion of the reserve for the Thomas/Woolsey wildfires and the Montecito mudslide; and (3) increased costs related to wildfire work and COVID-related costs for grid operations.

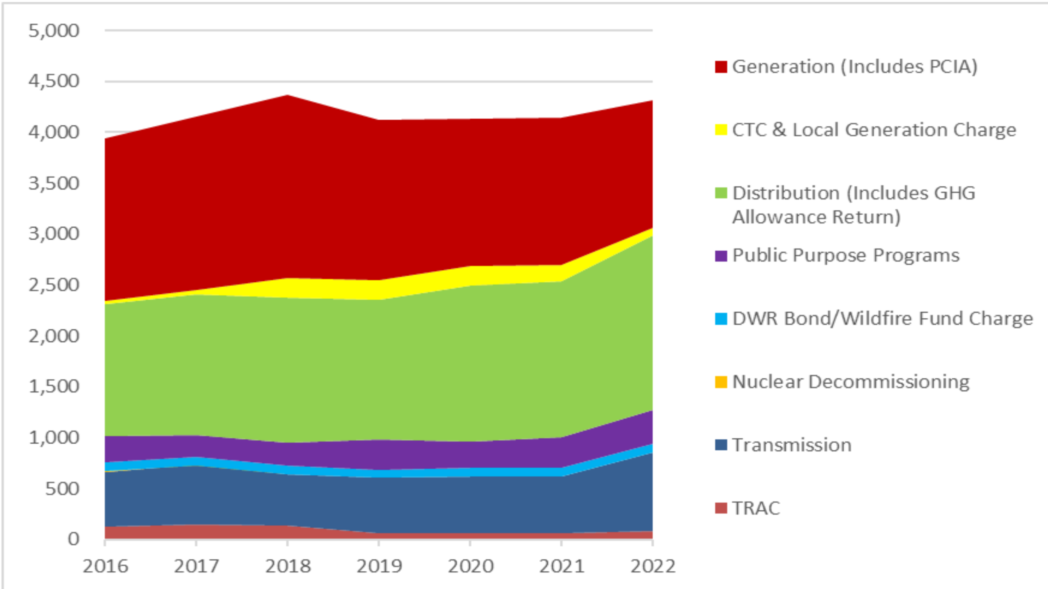
---

50 This system-level data does not model revenue shifts from different rate components such as PPP CARE surcharge to Distribution CARE line-item discount. *See* "California Alternative Rates for Energy Program Cost Considerations" in this report for more information about CARE program costs.

51 AB 841 (Ting, 2020) authorized in part the SEES program, which derives funds from IOU Energy Efficiency rolling portfolio funds to grant to schools for certain improvement projects.

52 Includes Base Transmission, Transmission Revenue Balancing Account Adjustment (TRBAA), Reliability Services Balancing Account Adjustment (RSBAA), and Transmission Access Charge Balancing Account Adjustment (TACBAA).

Figure 6: SDG&E January 1 Revenue Requirement by Rate Component Category[53] ($ millions)



SDG&E's revenue requirement corresponding to costs recovered in its generation rate component rose from 2016 through 2018 and has been decreasing since then, while the revenue requirement corresponding to costs recovered in the distribution and transmission rate components were moderately trending upward from 2016 to 2019, with a steeper increase starting in 2020 and continuing through 2022.

The primary driver of the **13 percent decrease in the generation revenue requirement** from 2021 to 2022 is attributable to expected Community Choice Aggregator (CCA) load departure in 2022. However, the decline in generation revenue requirement corresponds to a decline in the number of bundled customers – who are transitioning to CCA service for generation – and is not expected to result in declining rates.[54]

The primary drivers of the **11 percent increase in the distribution revenue requirement** from 2021 to 2022 are: (1) implementation of Attrition Year 2022 adjustments (resulting from escalation factors prescribed in the 2019 GRC); and (2) regulatory account under-collections.

---

[53] SDG&E did not implement its annual January 1, 2021 consolidated filing until February 1, 2021. As such, the 2021 revenues presented are the revenues in effect January 1, 2021 per AL 3619-E (rates effective October 1, 2020).

[54] CCA load departure should not harm (or benefit) bundled ratepayers due to application of the indifference principle through the Power Charge Indifference Adjustment (PCIA), a rate component intended to equalize cost sharing between departing load and bundled load.

The primary drivers of the **17 percent increase in PPP revenue requirement** from 2021 to 2022 are:[55] (1) increased funding for the California Alternative Rates for Energy (CARE) program[56] and amortization of the CARE balancing account under-collection; and (2) an increase in funding for the AB 841 School Energy Efficiency Stimulus (SEES) Program.[57] It is important to note that while the PPP revenue requirement has increased by 17 percent, PPP only makes up about 8 percent of the total revenue requirement on January 1, 2022, up from about 7 percent of the total revenue requirement on January 1, 2021.

The primary driver of the **38 percent increase in transmission revenue requirement**[58] from 2021 to 2022 are: (1) implementation of the revenue requirement for transmission costs as authorized by FERC, including additional revenue recovered from ratepayers for previously under-collected account balances.

Total Operating Expense and Capital-Related Revenue Requirement in January 1 Authorized Revenue Requirement

Figure 7 shows for each IOU the relative share of the total operating expense and total capital-related portion of the total revenue requirement.[59] All IOUs show a trend of this mix increasing from about a 65%/35% operating expense and capital-related revenue requirement mix in 2016 to about a 60%/40% mix in 2022. Operating expenses can have a larger immediate impact on rates in the short run, yet a smaller impact relative to capital-related expenses in the long run. Capital-related expenses have a larger cumulative impact on rates relative to operating expenses in the long run on a dollar-for-dollar basis as they are amortized in rate base over a longer time horizon and earn the IOUs a rate of return on rate base.

---

[55] This system-level data does not model revenue shifts from different rate components such as PPP CARE surcharge to Distribution CARE line-item discount. *See* "California Alternative Rates for Energy Program Cost Considerations" in this report for more information about CARE program costs.

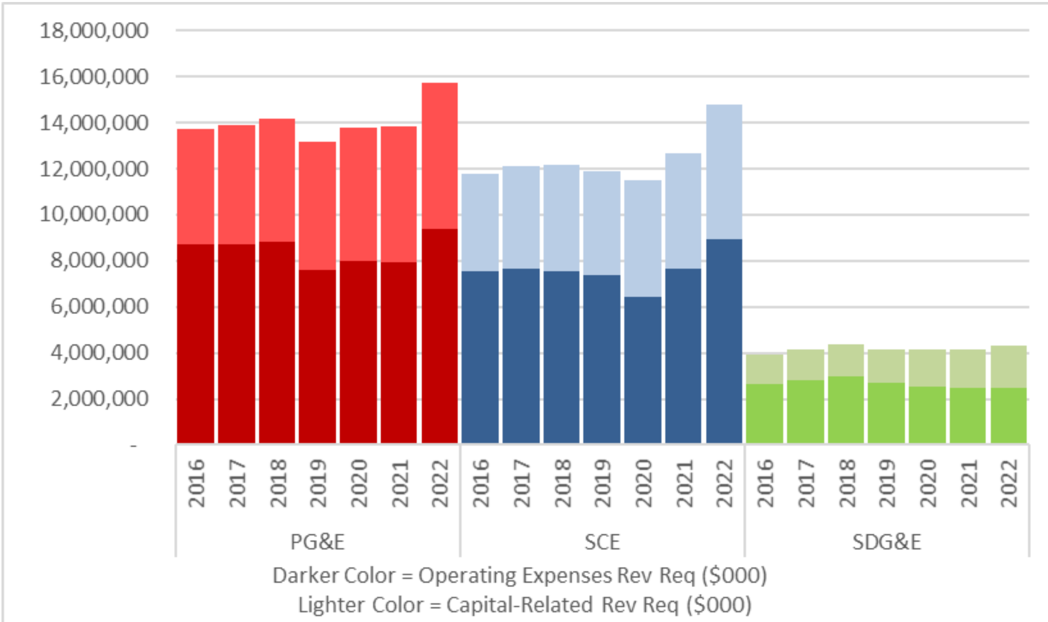
[56] A contributing factor for SDG&E's request to increase CARE revenue requirement is the CARE enrollment rate (i.e., enrolled customers divided by estimated eligible customers) still being over 100% at the end of 2021. This is due to increased households eligible for CARE during the pandemic, SDG&E's pandemic response to increase CARE marketing and temporarily suspending CARE income-verification per CPUC directives during the pandemic.

[57] AB 841 (Ting, 2020) authorized in part the SEES program, which derives funds from IOU Energy Efficiency rolling portfolio funds to grant to schools for certain improvement projects.

[58] Includes Base Transmission, Transmission Revenue Balancing Account Adjustment (TRBAA), Transmission Access Charge Balancing Account Adjustment (TACBAA), and Reliability Services.

[59] Revenue requirements that are not capital-related are classified as operating expenses

Figure 7: PG&E, SCE, and SDG&E Operating Expense and Capital-Related Revenue Requirements (January 1, $ millions)



Historical Distribution and Transmission Revenue Requirements and Rates

Recorded costs authorized for recovery during ratesetting proceedings include both operating expenses and capital-related expenditures, both of which must be converted to revenue requirement to be recovered from ratepayers as part of rates implementation. Operating expenses include operations and maintenance (O&M) expenses, administrative and general (A&G) expenses, and taxes.[60] Capital-related expenditures includes return on rate base and depreciation expenses (net of related tax effect).[61]

Operating expenses are generally passed through to ratepayers without markup and are recovered from ratepayers on a dollar-for-dollar basis with no amortized cost recovery over time, meaning the utility earns no profit on operating expenses and recovers those costs in the same year they were incurred. These expenses include all labor and non-labor expenses for a utility's operation and maintenance of its generation plants and distribution and transmission systems and A&G expenses, such as liability insurance and personnel costs.

---

60 O&M includes balancing accounts.

61 For purposes of this report, all expenditures are either operating expense or capital-related.

The utility collects a profit on **capital-related expenditures** from ratepayers, and capital expenditures are recovered over a long period of time as the underlying asset depreciates. Because of the multi-year recovery timeframe for capital investments, the revenue requirement in any given year is a fraction of the total capital-related revenue requirement. However, the capital costs will be included in rates for many years.

Distribution costs include operating expenses and distribution infrastructure capital-related expenditures. The corresponding revenue requirement reflects 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.

Similarly, transmission costs include operating expenses and transmission infrastructure capital-related expenditures. FERC reviews and approves Transmission Owner (TO) rate cases, which allow recovery of costs of service for the network transmission system under the California Independent System Operator's (CAISO) operative control. At FERC, the CPUC represents California ratepayers as an advocate for just and reasonable transmission rates.

Operating Expense Revenue Requirement

For PG&E and SCE, distribution and transmission operating expense revenue requirements have been increasing at an annual average rate greater than inflation.[62] The primary driver of these costs is wildfire mitigation work, including enhanced inspections and vegetation management efforts. Table 3 and Table 4 show distribution and transmission operating expense revenue requirements, respectively, for each of the IOUs in 2016 and 2022 along with the corresponding annual average percentage change.[63] Since 2016, distribution operating expense revenue requirement has been increasing on average by approximately 13 percent per year for PG&E, 8 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 115 percent per year for PG&E, 11 percent per year for SCE, and -3 percent per year for SDG&E.

[62] Annual average inflation rate (2016 base year) is 3.3 percent, based on Consumer Price Index (CPI) reported by the U.S. Department of Labor, Bureau of Labor Statistics, West Region, All Items, All Urban Consumers (not seasonally adjusted). 2022 held at 2021 rate (4.5 percent).

[63] In keeping with the time periods presented in previous Figures 4 through 7, data is shown from 2016. Data from year 2016 was first introduced in the 2019 SB 695 Report and has been continually updated since that time. For data prior to year 2016, see the AB 67 reports here.

For PG&E, substantial increases in transmission operating expense revenue requirement occurred over the periods 2016 – 2017 and 2019 – 2020.[64] The increase from 2016 to 2017 was driven by changes in the balancing accounts, with the Transmission Access Charge Balancing Account Adjustment (TACBAA)[65] 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.[66] The driver of the increase from 2019 to 2020 was expenses recovered in PG&E's transmission owner rate case at FERC.[67]

[64] 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.

[65] 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).

[66] 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. PG&E's current revenue requirement per MWh (i.e., the costs it must recover through the CAISO as a transmission owner) is $12.62., which is lower than the $16.39 TAC that it has to pay per MWh to use the high voltage grid as an LSE. Comparatively, SDG&E and SCE recover costs per MWh through the CAISO at $15.49 and $29.46, respectively.

[67] 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.

Table 3: Distribution Operating Expense Revenue Requirement, January 1, 2016 and January 1, 2022

Utility	2016	2022	Annual Average Percentage Change
PG&E	$ 1.412 billion	$ 2.528 billion	13.2%
SCE	$ 1.583 billion	$ 2.354 billion	8.1%
SDG&E	$ 0.482 billion	$ 0.553 billion	2.5%

Table 4: Transmission Operating Expense Revenue Requirement, January 1, 2016 and January 1, 2022

Utility	2016	2022	Annual Average Percentage Change
PG&E	$ 0.127 billion	$ 1.000 billion	114.6%
SCE	$ 0.291 billion	$ 0.474 billion	10.5%
SDG&E	$ 0.167 billion	$ 0.135 billion	-3.2%

Capital-Related Revenue Requirement

Each IOUs' rate base is the capital investment on which the utility receives an approved rate of return. **Rate base** is essentially the book value of the utility's assets after taking accumulated depreciation into account.[68]

$$\textit{Rate Base} = \textit{Net capital additions} - \textit{Accumulated depreciation}$$

When net capital additions exceed accumulated depreciation, which has generally been the case for PG&E, SCE, and SDG&E, rate base increases.

Distribution and transmission rate base has risen sharply in the period 2016 - 2022 despite flat to declining load growth over this same period. Table 5 and Table 6 show total distribution and transmission rate base, respectively, for each of the IOUs in 2016 and 2022 along with the corresponding annual average percentage change. Since 2016, distribution rate base has been increasing on average by approximately 7 percent per year for PG&E, 12 percent per year for SCE, and 9 percent per year for SDG&E. Over this same timeframe, transmission rate base has been

[68] 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.

increasing on average 18 percent per year for PG&E, 6 percent per year for SCE, and 10 percent per year for SDG&E.[69]

Table 5: Distribution Rate Base, January 1, 2016 and January 1, 2022

Utility	2016	2022	Annual Average Percentage Change
PG&E	$ 13.494 billion	$ 19.064 billion	6.9%
SCE	$ 14.913 billion	$ 25.808 billion	12.2%
SDG&E	$ 3.637 billion	$ 5.618 billion	9.1%

Table 6: Transmission Rate Base January 1, 2016 and January 1, 2022

Utility	2016	2022	Annual Average Percentage Change
PG&E	$ 5.371 billion	$ 11.208 billion	18.1%
SCE	$ 5.171 billion	$ 7.099 billion	6.2%
SDG&E	$ 2.896 billion	$ 4.602 billion	9.8%

Figure 8 through Figure 10 show distribution and transmission rate base and retail load delivered by each IOU over the 2016 – 2021 period.[70] Growth in distribution and transmission rate base, especially in the years 2020 and 2021, shows a mismatch with load delivered, with rate base continuing to increase while load delivered was declining overall or flat. This general trend is expected to continue as wildfire mitigation capital costs continue to increase rate base.[71]

---

[69] Rate base across all three IOUs began to increase at a faster rate starting in 2019; For more information *see* the annual AB 67 Reports.

[70] Retail load delivered from California Energy Commission (CEC) 2017 - 2021 Integrated Energy Policy Reports (IEPR), California Energy Demand Baseline Forecast, Load Serving Entity (LSE) tables, actual data only (2016 – 2020). 2021 data from utility data.

[71] Retail load delivered shown may be affected by weather, and 2020 and 2021 data may be affected by COVID-19 pandemic usage. In general, energy efficiency and behind-the-meter solar put pressure on a natural increase in sales, however, transportation electrification should begin to overtake this downward trend.

Figure 8: PG&E Distribution and Transmission Rate Base (January 1, $000) and Retail Load Delivered (GWh) (2016 – 2021)

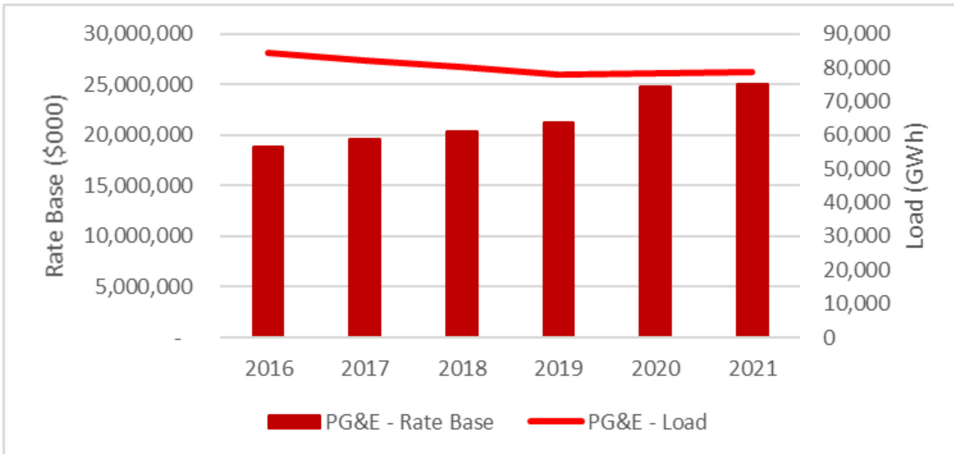


Figure 9: SCE Distribution and Transmission Rate Base (January 1, $000) and Retail Load Delivered (GWh) (2016 – 2021)

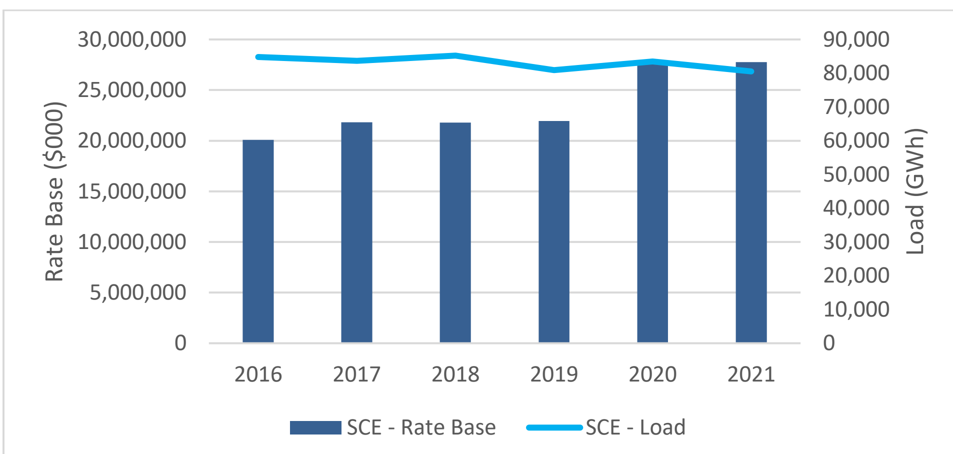
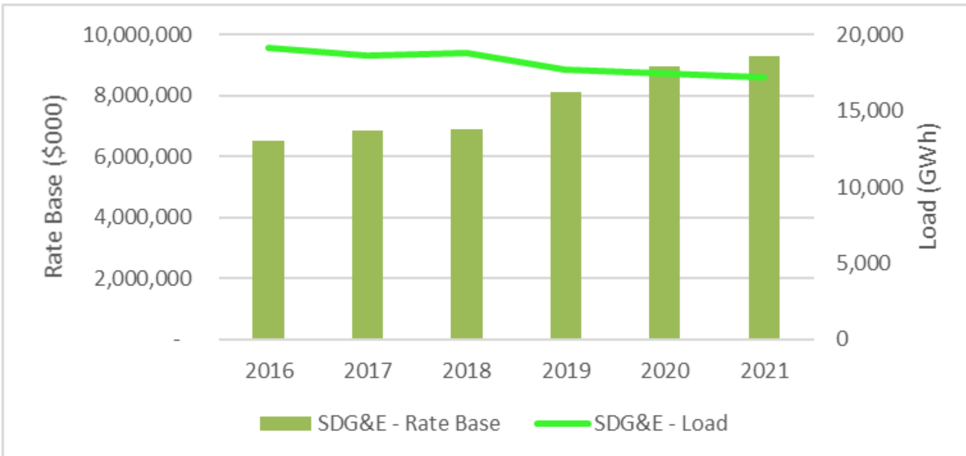


Figure 10: SDG&E Distribution and Transmission Rate Base (January 1, $000) and Retail Load Delivered (GWh) (2016 – 2021)



Each IOU's rate base provides a basis for computing return on rate base.[72] Return on rate base along with depreciation expenses (including related tax effects) comprise the utility's **capital-related revenue requirement.**

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

Increases in rate base over time result in higher depreciation expense revenue requirements and return on rate base revenue requirements as depreciation and return on rate base are now being calculated over an increasing base amount. This equates to higher capital-related revenue requirements collected from ratepayers over time.

Table 7 and Table 8 show distribution and transmission capital-related revenue requirements, respectively, for each of the IOUs in 2016 and 2022 along with the corresponding annual average percentage change. Since 2016, distribution capital-related revenue requirement has been increasing on average by approximately 3 percent per year for PG&E, 8 percent per year for SCE, and 7 percent per year for SDG&E; over this same timeframe, transmission capital-related revenue requirement has been increasing on average 10 percent per year for PG&E, 3 percent per year for SCE, and 13 percent per year for SDG&E.

[72] Return on rate base is calculated by multiplying the IOU's authorized rate of return by rate base. Return on rate base represents a return to shareholders paid by ratepayers.

Table 7: Distribution Capital-Related Revenue Requirement, January 1, 2016 and January 1, 2022

Utility	2016	2022	Annual Average Percentage Change
PG&E	$ 2.901 billion	$ 3.442 billion	3.1%
SCE	$ 2.929 billion	$ 4.383 billion	8.3%
SDG&E	$ 0.777 billion	$ 1.083 billion	6.6%

Table 8: Transmission Capital-Related Revenue Requirement, January 1, 2016 and January 1, 2022

Utility	2016	2022	Annual Average Percentage Change
PG&E	$ 1.057 billion	$ 1.707 billion	10.2%
SCE	$ 0.886 billion	$ 1.018 billion	2.5%
SDG&E	$ 0.365 billion	$ 0.638 billion	12.5%

Total Distribution and Transmission Revenue Requirement

Table 9 and Table 10 show the sum of the operating expenses and capital-related revenue requirements for distribution and transmission, including all distribution and transmission balancing accounts balances, presented in previous tables. Since 2016, distribution revenue requirements have been increasing on average by approximately 6 percent per year for PG&E, 8 percent per year for SCE, and 5 percent per year for SDG&E; over this same timeframe, transmission revenue requirements have been increasing on average 22 percent per year for PG&E, 4 percent per year for SCE, and 8 percent per year for SDG&E. Tables showing the wildfire mitigation costs embedded in distribution and transmission revenue requirements follow the tables showing total distribution and transmission revenue requirements.

Table 9: Distribution Revenue Requirement, January 1, 2016 and January 1, 2022

Utility	2016	2022	Annual Average Percentage Change
PG&E	$ 4.313 billion	$ 5.971 billion	6.4%
SCE	$ 4.512 billion	$ 6.738 billion	8.2%
SDG&E	$ 1.259 billion	$ 1.636 billion	5.0%

**Table 10: Transmission Revenue Requirement,
January 1, 2016 and January 1, 2022**

Utility	2016	2022	Annual Average Percentage Change
PG&E	$ 1.183 billion	$ 2.706 billion	21.5%
SCE	$ 1.177 billion	$ 1.491 billion	4.4%
SDG&E	$ 0.531 billion	$ 0.773 billion	7.6%

Historical Wildfire-Related Costs

Total distribution and transmission revenue requirement reflected in Table 9 and Table 10 includes wildfire-related costs that fall into several categories.[73] First, the IOUs incur costs to implement wildfire mitigation activities. The costs associated with wildfire mitigation activities are then recovered by the IOUs in GRCs or through separate applications.[74]

The CPUC also allows the IOUs to recover certain wildfire-related costs for liabilities, including insurance premiums, which the IOUs track through a mechanism called a Wildfire Expense Memorandum Account (WEMA). WEMAs track wildfire related liability costs, and no other category. WEMAs are designed to allow the utility to track its costs incurred for claims made against the company as a result of property losses, in addition to other incremental liability costs including higher-than-forecasted insurance premiums and legal fees.

In 2019, the Legislature also established a Wildfire Fund for excess liabilities. This is discussed in more detail below in the section on legislative and regulatory background.

Legislative and Regulatory Background

SB 901 (Dodd, 2018) and AB 1054 (Holden, 2019) require electric utilities to prepare and submit wildfire mitigation plans (WMPs), which describe the level of wildfire risk in their service territories and how they intend to address those risks.[75] The WMPs cover a three-year period with new

---

[73] For PG&E and SCE, these wildfire costs began to show up in revenue requirement in significant amounts starting in 2021.

[74] For example, PG&E's A.20-09-019 and A.21-09-008 seek recovery of incremental wildfire mitigation spending in years 2017-2020 recorded in memorandum accounts. SCE A.19-08-013 Track 3 requests recovery of incremental 2018-2020 wildfire mitigation spending recorded in memorandum accounts.

[75] *See* each IOU's WMP at: https://energysafety.ca.gov/what-we-do/electrical-infrastructure-safety/wildfire-mitigation-and-safety/wildfire-mitigation-plans/2022-wmp/.

comprehensive plans to be filed at least once every three years and annual updates to the plans in between.

AB 1054 created a $21 billion Wildfire Fund funded equally by ratepayers and utility shareholders. Utility shareholders will contribute approximately $10.5 billion to the Wildfire Fund through annual payments until 2030, and ratepayers will fund an additional $10.5 billion through a new non-bypassable charge (NBC). D. 21-12-006 adopted a charge of $0.00652 per kilowatt-hour (kWh) for calendar year 2022. This amounts to approximately $3 per month for an average residential customer using 500 kWh per month.[76]

The Wildfire Fund is designed to act as an insurance fund for the utilities and can be used to pay costs resulting from utility-caused wildfires, provided certain conditions are met by the utility. While the fund represents an ongoing surcharge to ratepayers, it could reduce costs to ratepayers over time by creating more certainty for utility investors, and thus reducing utility operating and borrowing costs.

In addition to creating the Wildfire Fund, AB 1054 contains two separate benefits for ratepayers related to WMP capital spending. AB 1054 excludes the first $5 billion of WMP capital spending from earning a Return on Equity (ROE). This reduces rates directly by eliminating the shareholder profit portion of the return on rate base of $5 billion in WMP capital spending. 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.[77] These equity rate base exclusions could save ratepayers as much as $2 billion in ROE that would otherwise be collected in rates over time.

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 utility 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. On July 8, 2020, SCE filed Application (A.)20-07-008 with the CPUC, becoming the first utility to file for this securitization provision of AB 1054. In D.20-11-007, the CPUC authorized the Financing Order allowing the securitization of $337.1 million in recovery bonds, subject to certain conditions. Accordingly, the securitized bonds were issued and a $19.3 million annual revenue requirement in recovery bond fixed recovery charges was implemented in rates effective June 1, 2021.

The Financing Order for SCE's second issuance of up to $526 million in recovery bonds pursuant to AB 1054 was authorized in D.21-10-025.[78] While the securitized bonds have been issued, the

---

[76] CARE and Medical Baseline customers are exempt from paying the non-bypassable charge.

[77] These amounts are sometimes referred to as "equity rate base exclusion" amounts.

[78] *See* docket for A.21-06-016.

resulting recovery bond fixed recovery charges remain pending for implementation in rates at the time of writing.[79]

Similarly, pursuant to AB 1054, PG&E filed A.21-02-020 requesting authority to implement a fixed recovery charge and issue recovery bonds to finance up to $1.2 billion of approved wildfire mitigation capital expenditures. D.21-06-030 approved PG&E's request which resulted in a securitized bond issuance totaling $860 million with about $82 million in recovery bond fixed recovery charges implemented in rates effective December 1, 2021.

Costs in Rates

SB 901 and AB 1054 permitted the IOUs to open memorandum accounts in 2019 to track spending to implement their WMPs. These memorandum accounts permitted the IOUs to immediately begin implementing enhanced wildfire mitigation efforts and tracking the associated costs, without having to wait until their next GRC cycle. The IOUs are allowed to seek recovery of this spending in their GRCs or through a separate application,[80] after the conclusion of the time period covered by the plan. Therefore, there can be a multi-year lag between when spending takes place and when it is reflected in rates. Going forward, the IOUs are expected to forecast the majority of their WMP costs in their GRCs, reducing the amounts tracked in memorandum accounts and the associated lag in cost recovery.

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 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. The IOUs also track eligible costs to respond to catastrophic events, including wildfires, in their Catastrophic Event Memorandum Accounts (CEMA). Permissible CEMA expenses include restoring utility services to customers; repairing, replacing, or restoring damaged utility facilities; and complying with government agency orders resulting from declared disasters.

Since 2019 (and as of fourth quarter 2021), the IOUs have been authorized to collectively place in rates approximately $6.8 billion of wildfire mitigation costs to support the state's wildfire prevention efforts and approximately $4.5 billion for wildfire insurance premiums and catastrophic events costs.[81] Together, wildfire mitigation and wildfire insurance (and catastrophic events) costs are

---

[79] Per SCE Advice Letter 4760-E, the amount expected to implement in rates is $31.7 million.

[80] For example, recovery of FERC-related costs is done in Transmission Owner rate cases.

[81] PG&E and SDG&E (2019 – 2021) and SCE (2019 – 2020): 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; SCE (2021): Insurance amounts are wildfire only.

referred to as "wildfire costs." Total wildfire costs placed in rates between 2019 and 2021 are approximately $11.3 billion as shown in Table 11.[82]

Table 11: Total Wildfire Costs in Rates
(2019 – 2021, Year-End, $ billions)

Utility	Total Wildfire Costs in 2019 – 2021 Rates ($ billions, sum of columns to right)	Total Wildfire Mitigation Costs in 2019 - 2021 Rates ($ billions)	Total Wildfire Insurance / Catastrophic Events Costs in 2019 – 2021 Rates ($ billions)
PG&E	**$6.8**	$4.8	$2.0
SCE	**$3.9**	$1.6	$2.3
SDG&E	**$0.6**	$0.4	$0.2
Total	**$11.3**	$6.8	$4.5

Table 12 through Table 14 show incremental revenue requirement reflected in 2019 - 2021 rates corresponding to each IOU's wildfire mitigation and wildfire insurance/catastrophic events costs by CPUC and FERC jurisdiction.[83] CPUC jurisdictional wildfire mitigation costs are generally recovered through the distribution rate component; however, starting in 2021, PG&E and SCE recovered securitized wildfire mitigation costs through a dedicated securitization rate component.[84] Similarly, starting in the fourth quarter of 2020, all IOUs recovered Wildfire Fund costs through a dedicated wildfire fund rate component.[85]

Table 12 and Table 13 for PG&E and SCE show a significant revenue requirement in 2021 year-end rates related to wildfire mitigation and wildfire insurance / catastrophic events. For PG&E, about two-thirds of the wildfire mitigation revenue requirement in 2021 was authorized in its 2020 GRC

---

82 There is not a 1:1 relationship between costs and revenue requirement placed in rates. *See* Table 12 through Table 14 for the equivalent revenue requirement in rates. SDG&E declined to provide 2021 operating expense and capital-related costs for wildfire mitigation and wildfire insurance, stating that these costs "are imputed for the purposes of the yearly Risk Spending Accountability Reports (RSAR) and are typically disclosed at that time." SDG&E plans to file its next RSAR in July 2022.

83 Rates in effect at year-end; includes Franchise Fees & Uncollectibles (FF&U) unless otherwise indicated. FERC-related revenue requirements are recorded costs unless otherwise indicated.

84 PG&E: *See* D.21-06-030; 2021 incremental revenue requirement totaled $82.3 million; SCE: *See* D.20-11-007; 2021 incremental revenue requirement totaled $19.3 million.

85 The rate component is generally known as the Wildfire Fund non-bypassable charge; actual name varies by IOU.

proceeding.[86] In SCE's case, about 90 percent of the 2021 wildfire mitigation revenue requirement was authorized in its 2021 GRC and Grid Safety and Resiliency Program proceedings.[87] For both IOUs, wildfire liability insurance is approximately $1 billion.[88]

Table 14 for SDG&E shows a lower relative percentage of wildfire 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.[89] It should be noted, though, that until recently when it filed for interim cost recovery, SDG&E had not filed for recovery of costs recorded in its Wildfire Mitigation Plan Balancing Accounts (WMPBAs) for costs recorded since 2019.[90]

---

86 *See* D.20-12-005.

87 *See* D.21-08-036 (GRC) and D.20-04-013 (GSRP). Operating expense component includes all of SCE's vegetation management authorized revenue requirement since SCE's approved cost recovery mechanism for vegetation management does not distinguish between wildfire and non-wildfire vegetation management.

88 PG&E: Insurance and liability-related $572 million + Wildfire Fund $403 million. 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. SCE: Insurance and liability-related $687 million + Wildfire Fund $393 million. Wildfire liability insurance is grouped within A&G expense category.

89 *See* the 2021 SB 695 Report for additional detail about operating expenses and capital costs incurred for wildfire prevention over the period 2007 – 2018. Since costs may be implemented in rates in a different year than year incurred, wildfire expenses and capital incurred by SDG&E starting in 2007 could impact rates significantly in a later period.

90 *See* A.21-07-017.

Table 12: PG&E Wildfire Mitigation and Wildfire Insurance/ Catastrophic Events Revenue Requirement (2019 – 2021, Year-End, $ millions)

	2019 ($ millions)		2020 ($ millions)		2021 ($ millions)	
PG&E	Operating Expense	Capital-Related	Operating Expense	Capital-Related	Operating Expense	Capital-Related
Wildfire Mitigation – CPUC Jurisdictional (Unsecuritized)	-	($1.0)	-	-	$1,346.0	($32.5)
Wildfire Mitigation – CPUC Jurisdictional (AB 1054 Securitization)	-	-	-	-	-	$82.3
Wildfire Mitigation – FERC Jurisdictional	-	-	$16.0	$1.5	$138.4	$15.4
Wildfire Insurance & Catastrophic Events –CPUC Jurisdictional (Non-AB 1054 Wildfire Fund)[91]	$68.9	$5.7	$275.5	$22.9	$684.3	$17.9
Wildfire Insurance & Catastrophic Events –CPUC Jurisdictional (AB 1054 Wildfire Fund)	-	-	$427.3	-	$403.4	-
Wildfire Insurance & Catastrophic Events –FERC Jurisdictional[92]	Not Provided	Not Provided	Not Provided	Not Provided	Not Provided	Not Provided
Total Wildfire (Operating Expense and Capital-Related)	**$73.6**		**$743.2**		**$2,655.2**	
Total Revenue Requirement	**$13,561.6**		**$14,145.9**		**$14,381.7**	
% Wildfire Revenue Requirement to Total Revenue Requirement	**0.5%**		**5.3%**		**18.5%**	

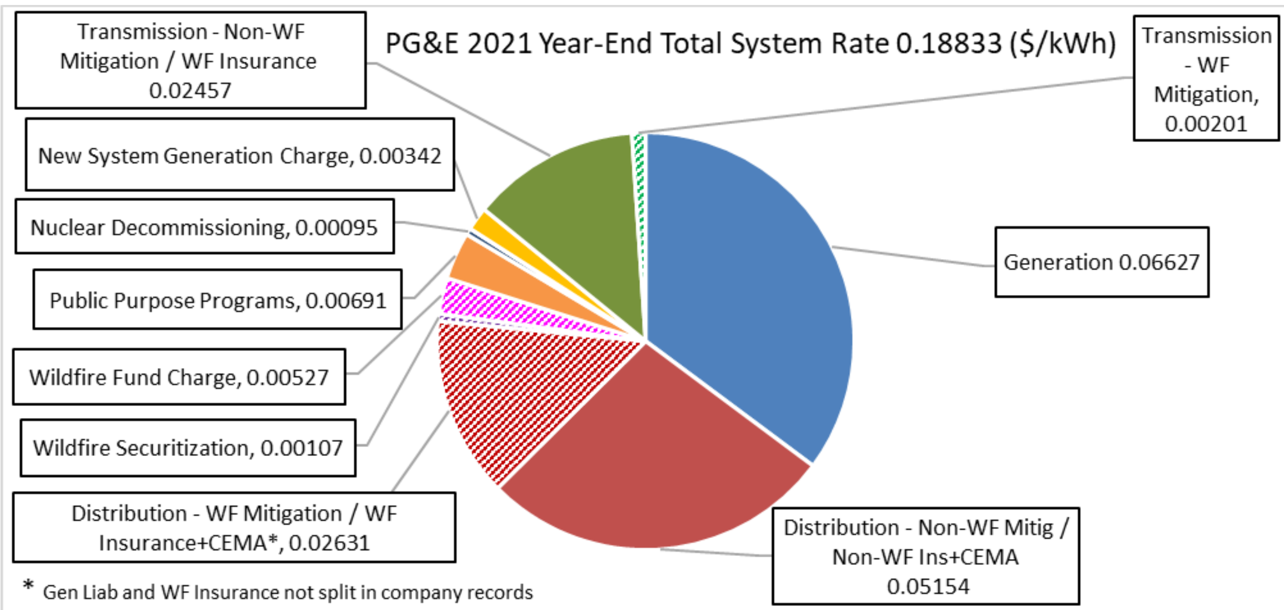
Table 12, above, shows how significant the wildfire-related operating expense revenue requirement was for PG&E in 2021. This revenue requirement is primarily driven by the amortization of 2020 GRC adopted costs and 2021 costs for wildfire mitigation programs; of the $1.327 billion in 2021 operating expense revenue requirement, $1.024 billion corresponds to 2021 operating expense cost

[91] 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. The following recovered in 2021 corresponds to the $684 million (M) in company wildfire insurance and response revenue requirement: 2020 GRC $572M (D.20-12-005); $112M 2018 CEMA Interim Rate Relief (D.19-04-039) & 2019 CEMA (D.20-11-035).

[92] PG&E declined to provide FERC-related wildfire insurance and catastrophic events data.

recovery from the 2020 GRC Decision.[93] Figure 11 shows the composition of PG&E's total system rate (i.e., bundled and unbundled) for rates effective year-end 2021. The cross-hatched areas represent the data in Table 12, with wildfire cost-related breakouts reflected for distribution and transmission revenue requirements.[94]

Figure 11: PG&E 2021 Total System Rate by Components with Additional Wildfire Cost Breakout
(Year-End, $/kWh)



[93] *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. The following recovered in 2021 corresponds to the 2020 GRC Decision revenue requirement $1.024 billion (in $ millions (M)): 2020 VM Balancing Account (BA) up-to authorized $251.9M; 2020 VMBA 20% above authorized $110.8M; 2021 VMBA up-to authorized $609.4M; 2020 WMBA up-to authorized $15.3M; 2020 WMBA 15% above authorized $1.3M; 2021 WMBA up-to authorized $35.0M.

[94] Not shown: CTC (does not register in rate displayed out to five decimal places).

Table 13: SCE Wildfire Mitigation and Wildfire Insurance/ Catastrophic Events Revenue Requirement (2019 – 2021, Year-End, $ millions)

	2019 ($ millions)		2020 ($ millions)		2021 ($ millions)	
SCE	Operating Expense	Capital-Related	Operating Expense	Capital-Related	Operating Expense	Capital-Related
Wildfire Mitigation – CPUC Jurisdictional (Unsecuritized)[95]	$69.2	-	$80.1	-	$407.2	$69.1
Wildfire Mitigation – CPUC Jurisdictional (AB 1054 Securitization)	-	-	-	-	-	$19.3
Wildfire Mitigation – FERC Jurisdictional	-	-	-	$0.6	$30.7	$2.4
Wildfire Insurance & Catastrophic Events –CPUC Jurisdictional (Non-AB 1054 Wildfire Fund)[96]	$218.3	-	$329.5	-	$770.0	-
Wildfire Insurance & Catastrophic Events –CPUC Jurisdictional (AB 1054 Wildfire Fund)	-	-	$428.1	-	$393.1	-
Wildfire Insurance & Catastrophic Events –FERC Jurisdictional[97]	$1.0	-	$168.1	-	$26.5	-
Total Wildfire (Operating Expense and Capital-Related)	**$288.5**		**$1,006.4**		**$1,718.3**	
Total Revenue Requirement	**$11,120.6**		**$12,665.3**		**$14,294.4**	
% Wildfire Revenue Requirement to Total Revenue Requirement	**2.6%**		**7.9%**		**12.0%**	

For SCE, aside from company wildfire insurance and response revenue requirement of about $770 million (tracked in SCE's CEMA),[98] the largest 2021 revenue requirement is the wildfire mitigation operating expense of approximately $407.2 million. Figure 12 shows the composition of SCE's total

---

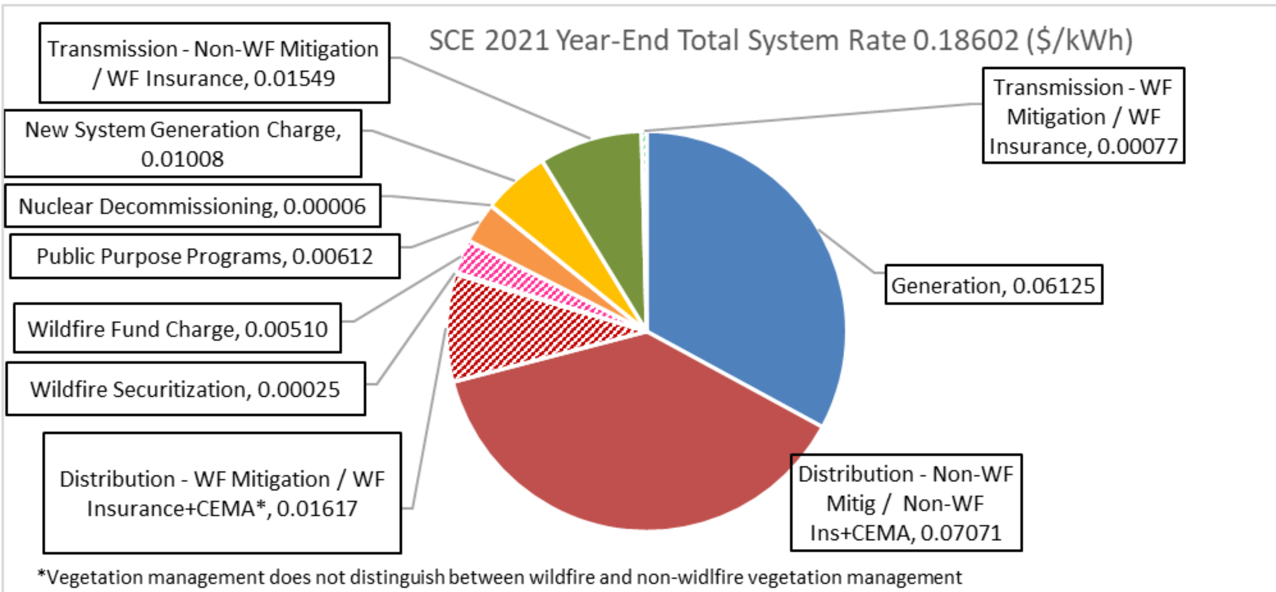
[95] Operating expense component includes all of SCE's vegetation management authorized revenue requirement since SCE's approved cost recovery mechanism for vegetation management does not distinguish between wildfire and non-wildfire vegetation management.

[96] Starting in 2021, insurance amounts are wildfire only (prior to 2021, general and wildfire liability insurance were not separated).

[97] FERC jurisdictional includes insurance premiums and FERC portion of the accrued liabilities net of insurance.

system rate (i.e., bundled and unbundled) for rates effective year-end 2021. The cross-hatched areas represent the data in Table 13, with wildfire cost-related breakouts reflected for distribution and transmission revenue requirements.

Figure 12: SCE 2021 Total System Rate by Components with Additional Wildfire Cost Breakout (Year-End, $/kWh)



[98] The following recovered in 2021 corresponds to the $770 million (M) in company wildfire insurance and response revenue requirement: 2021 GRC Insurance $434M (D.21-08-036); WEMA $253M (D.20-09-025); CEMA - 2017/2018 Drought $83M (D.21-08-024).

Table 14: SDG&E Wildfire Mitigation and Wildfire Insurance/ Catastrophic Events Revenue Requirement (2019 – 2021, Year-End, $ millions)

	2019 ($ millions)		2020 ($ millions)		2021 ($ millions)	
SDG&E	**Operating Expenses**	**Capital-Related**	**Operating Expenses**	**Capital-Related**	**Operating Expenses**	**Capital-Related**
Wildfire Mitigation – CPUC Jurisdictional (Unsecuritized)	$25.8	$11.8	$28.3	$37.4	$29.0	$44.7
Wildfire Mitigation – CPUC Jurisdictional (AB 1054 Securitization)	-	-	-	-	-	-
Wildfire Mitigation – FERC Jurisdictional[99]	Not Provided	Not Provided	Not Provided	Not Provided	Not Provided	Not Provided
Wildfire Insurance & Catastrophic Events –CPUC Jurisdictional (Non-AB 1054 Wildfire Fund)[100]	$73.9	-	$75.9	-	$135.7	-
Wildfire Insurance & Catastrophic Events –CPUC Jurisdictional (AB 1054 Wildfire Fund)	-	-	$22.6	-	$90.2	-
Wildfire Insurance & Catastrophic Events –FERC Jurisdictional	$14.7	-	$18.3	-	$23.6	-
Total (Operating Expense and Capital-Related)	**$126.2**		**$182.5**		**$323.2**	
Total Revenue Requirement	**$4,211.7**		**$4,142.0**		**$4,334.8**	
% Wildfire Revenue Requirement to Total Revenue Requirement	**3.0%**		**4.4%**		**7.5%**	

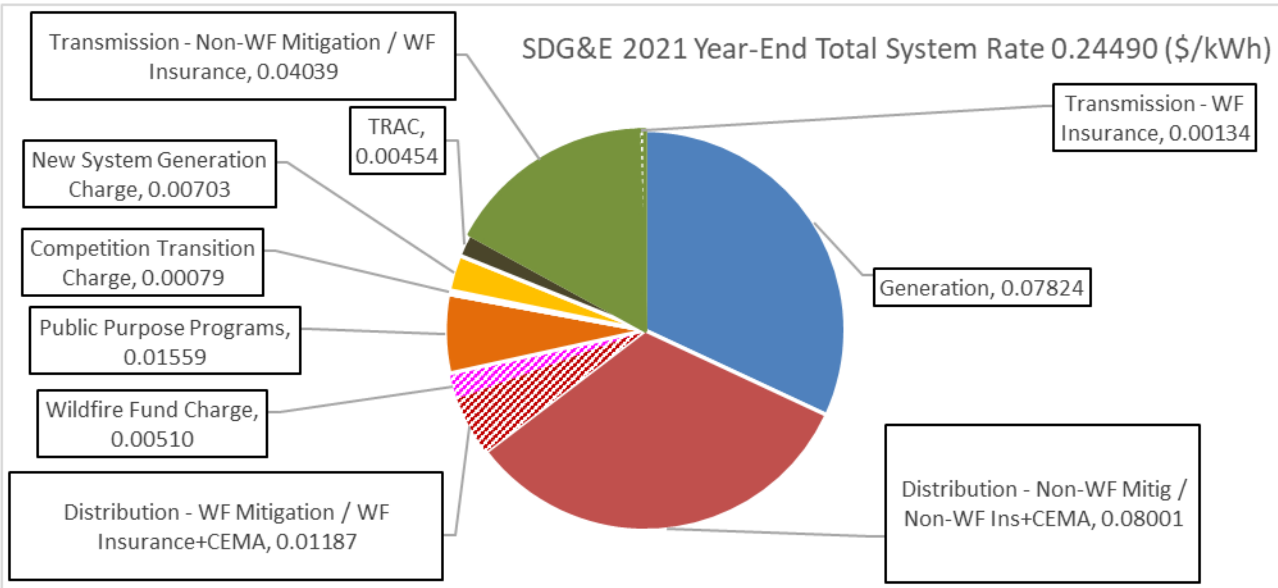
Figure 13 shows the composition of SDG&E's total system rate (i.e., bundled and unbundled) for rates effective year-end 2021. The cross-hatched areas represent the data in Table 14, with wildfire cost-related breakouts reflected for distribution and transmission revenue requirements.[101]

[99] SDG&E declined to provide FERC-related wildfire mitigation revenue requirement, stating, "SDG&E does not separately track or compile WMP-related costs and expenditures for transmission in the ordinary course of business, as these costs are not subject to the CPUC's jurisdiction."

[100] Includes Liability Insurance Premiums Balancing Account (LIPBA) balance $56.3 million (excludes FF&U); a small portion of the LIPBA balance is unrelated to wildfire insurance.

[101] Not shown: Nuclear Decommissioning (does not register in rate displayed out to five decimal places).

Figure 13: SDG&E 2021 Total System Rate by Components with Additional Wildfire Cost Breakout
(Year-End, $/kWh)



As previously noted, wildfire costs began to show up in revenue requirement in significant amounts starting in 2021. The impact of this incremental revenue requirement on bundled residential average bills in 2021 is shown in Table 15.[102]

Table 15: PG&E, SCE, and SDG&E Wildfire Costs Portion of 2021 Monthly Bill, Bundled Residential Customers
(Year-End, $/month)

	Total Bill ($/month)	Wildfire Mitigation Portion ($/month)	Wildfire Mitigation Portion (%)
PG&E	$139.68	$22.14	15.9%
SCE	$135.48	$16.19	12.0%
SDG&E	$183.21	$13.95	7.6%

102 Year-end 2021 rates in effect. Typical Non-CARE customer using 500 kWh (PG&E Climate Zone S, SCE Climate Zone 9, and SDG&E Inland Climate Zone).

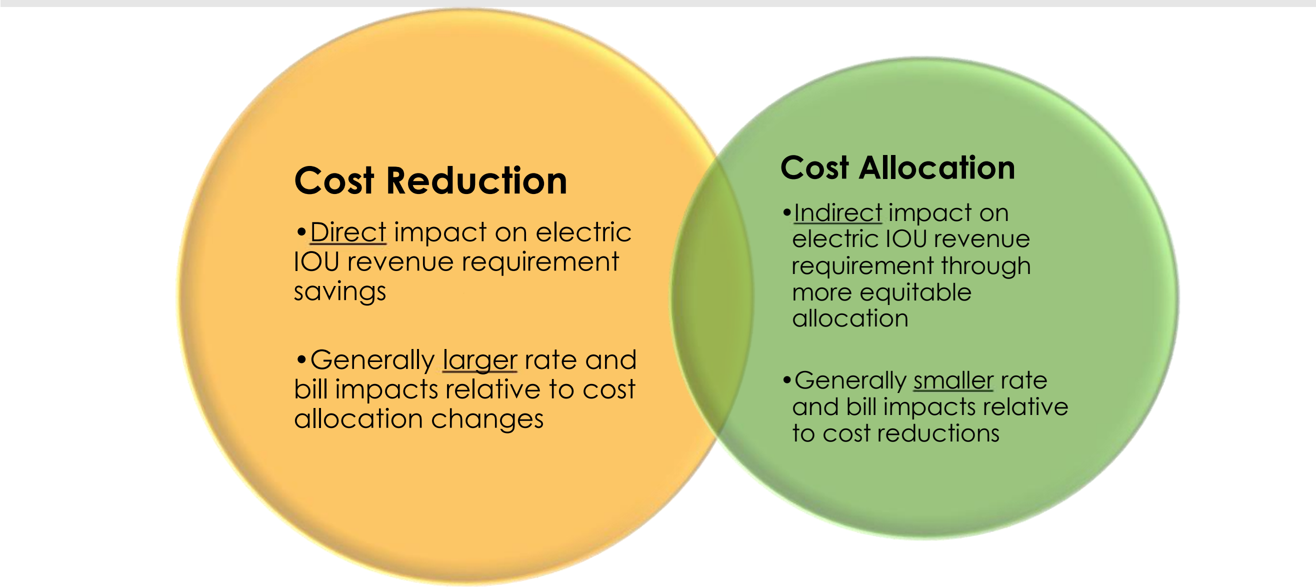
Methods to Reduce Cost and Rate Impacts

There are two principal tools to reduce cost and rate impacts as well as promote equity and affordability: cost reduction and cost allocation as shown in Figure 14. Cost reduction strategies result in a direct impact on electric IOU revenue requirement savings because they reduce the size of the overall "pie" of costs that utilities are authorized to recover through rates, and this benefits all customers. Cost allocation and rate design strategies redistribute costs and have an indirect impact, because they reduce system costs only to the extent that they can alter customer incentives to achieve greater alignment between energy usage and grid conditions over time.[103]

In general, cost reduction strategies have a greater impact than cost allocation strategies, because they directly reduce the amount of revenue that must be recovered through rates. Another distinguishing factor in the effectiveness of cost reduction strategies is whether they target operating expenses versus capital expenses. Reductions in operating expenses tend to have a greater short-term impact on rates, because operating expenses are collected in full once they are authorized while recovery of capital costs is amortized over the life of the asset. On the other hand, dollar for dollar reductions in capital costs reduce rates more over the long-term because they reduce cost recovery for both depreciation and rate of return.

[103] Cost allocation and rate design strategies may also redistribute costs among groups or classes of customers, with or without achieving overall cost savings at the system level.

Figure 14: Cost Reduction and Cost Allocation Processes



The proposals presented by stakeholders at the 2022 En Banc hearing as either primarily cost reduction or cost allocation strategies, although a couple of the proposals presented may share both cost allocation and reduction features, as identified in Table 16 below. The CPUC is reviewing these proposals in the Affordability proceeding. Several of these proposals will be further described later in this report.[104]

---

[104] Pursuant to the Assigned Commissioner's Ruling issued January 18, 2022 in Phase 3 of the Affordability proceeding, a ruling soliciting recommendations and considerations from stakeholders on proposed strategies to mitigate energy rate increases is forthcoming in the second quarter of 2022. A proposed decision in Phase 3 of the Affordability proceeding is expected to be issued by the third quarter of 2023.

Table 16: 2022 Affordability En Banc Stakeholder Proposals by Cost Process[105]

Cost Reduction	Cost Allocation
Implement Percent of Income Payment Plans at full-scale[106] that are publicly subsidized.	Implement Percent of Income Payment Plans at full scale, without public subsidy.
Move Public Purpose Programs costs to the state's General Fund.	Implement a fixed charge using the income graduation currently existing in rates (CARE, FERA, and Non-CARE/FERA[107]).
Move wildfire mitigation investments to the state General Fund.	Implement an income-graduated fixed charge for which the amount charged progressively increases for higher income households.
Fund the AB 1054 Wildfire Fund Charge with non-ratepayer sources.	Adopt wildfire mitigation surcharges for customers in Tier 3 fire threat areas.
Reduce electric IOUs' authorized Return-on-Equity.	Prioritize vulnerable communities for baseline and rate adjustments.
Require IOUs to submit Consumer Price Index -based alternative proposals in GRCs to reduce anchor bias.	Target policy and rate design changes to benefit customers in areas suffering air quality problems.
Levy point-of-sale surcharge on internal-combustion engine (ICE) vehicle sales to fund transportation electrification programs.	Reduce the use of balancing accounts in CPUC ratemaking proceedings.
Pay for building electrification with point-of-sale requirements when buildings and homes are bought and sold.	Capacity of kWh charge proposals on DER imports/exports.
Allow IOUs more flexibility in selling renewable energy credits.	Authorize utilities to deploy capital and recover cost for building decarbonization upgrades via tariffed on-bill structures that enable participation regardless of income, credit score, or renter status.
Implement additional controls on increasing transmission costs.	Rate or infrastructure planning mechanisms to avoid excessive gas infrastructure costs falling disproportionately on residential customers who cannot electrify.
Eliminate the fixed energy price option for must-take contracts with qualifying facilities.	Determine if electrification warrants securitization and/or accelerated depreciation of assets.
Approve utility self-insurance for wildfire-related liabilities	Renewable Balancing Services proposal that adjusts rates for different gas users at different times of day.
Replace ratepayer subsidies and incentives with regulatory mandates.	Evaluate natural gas rates and affordability in coordination with the Long-Term Gas Planning Rulemaking.
State ownership and financing of transmission infrastructure.	
Determine how to efficiently prune the gas system while providing safety.	

Wildfire-related Stakeholder Proposals in the 2022 Affordability Proceeding En Banc

[105] The list of proposals here may differ slightly in content and number from the preliminary list of proposals enumerated in the Affordability proceeding (R.18-07-006) Phase 3 scoping ruling and the 2022 Affordability en banc agenda, which left room for additional ideas and scenarios to be raised.

[106] Percent of income payment plan pilots are currently in development following authorization in D.21-10-012.

[107] California Alternative Rates for Energy (CARE) and Family Electric Rate Assistance (FERA) customers receive bill discounts.

With respect to limiting wildfire-related costs and rate increases, stakeholders presented several novel approaches at the CPUC 2022 Affordability Proceeding[108] En Banc, held February 28, 2022 and March 1, 2022.[109] Additionally, the IOUs were asked to comment on specific ideas presented at the En Banc as part of their recommendations to limit cost and rate increases consistent with the state's energy and environmental goals for reducing greenhouse gases, as required by Public Utilities Code Section 913.1.[110] The points summarized here reflect the comments made by stakeholders and do not include any evaluation of the recommendations, as these proposals are still being considered by the CPUC in a formal proceeding.

Mohit Chhabra, Senior Scientist, Climate & Clean Energy Program, Natural Resources Defense Council (NRDC): Mr. Chhabra explored the idea of reducing revenue requirement and corresponding rates by funding the AB 1054 Wildfire Fund Charge with non-ratepayer sources.[111] A high-level estimate that NRDC produced for PG&E's service territory showed a rate reduction of about 2 percent for customers who are not exempt from the charge (i.e., all Non-CARE residential customers and all other non-residential customers).[112]

Michael Wara, Director, Climate and Energy Policy Program, Woods Institute for the Environment, Stanford: Dr. Wara proposed looking closer at wildfire cost causation – i.e., why it is likely more expensive to serve customers who reside in high wildfire threat areas than those who don't – and considering a fixed charge on the bills of customers in high wildfire-threat areas that would defray *some* of these costs. While this idea does not cut overall costs, it allocates them more closely on a cost-sharing basis to those who may benefit most from wildfire hardening of the grid.[113] This proposal could shift costs away from those low-income residents who do not live in high wildfire-threat areas.[114]

108 *See* docket for R.18-07-006.

109 *See* 2-28-22 Hearing and 3-1-22 Hearing.

110 The comments provided by the IOUs are subject to change as more formal comments are submitted in the Affordability proceeding and as issues are considered in this and related proceedings. Full responses can be found in the links provided in Appendix A.

111 Mr. Chhabra (NRDC) explored other revenue reduction ideas in addition to this one regarding the AB 1054 Wildfire Fund Charge.

112 CARE customers are exempt from this charge and would not see a rate reduction. This calculation has not been verified but may be reviewed as part of Phase 3 of the Affordability proceeding.

113 Reference to a potential model is made to the State's Fire Prevention Fee that was in effect from 2011 – 2017 that required the Department of Forestry and Fire Protection (CAL FIRE) to provide the California Department of Tax and Fee Administration (CDTFA), a list of owners of habitable structures located in the State's Responsibility Area (SRA) and the amount of fee(s) to be assessed on each structure. The CDTFA then issues the billings and collects the fees. The SRA is the area of the state where the State of California is financially responsible for the prevention and suppression of wildfires.

114 Consideration of this proposal may include exempting low-income customers who live in high-wildfire threat areas from the surcharge.

IOU Comments on En Banc Topics: The IOUs were asked to comment specifically on moving wildfire mitigation cost recovery to the General Fund.

PG&E in general supports this concept and states it will continue to work with the state and policymakers to identify areas that may be more appropriately funded by all Californians to help PG&E minimize impacts to customers. In order to have the highest impact on near-term affordability, PG&E believes the state should focus on using state funds to reduce operating expenses, which would have a larger impact in the near-term than reductions in capital related costs.

SCE's statements on this topic centered on maintaining IOU control and oversight of IOU wildfire mitigation activities. SCE notes cost recovery for approved IOU wildfire mitigation activities should be covered by the most stable funding source possible and that "moving" wildfire mitigation funding to California's General Fund could introduce an unnecessary and unpredictable level of volatility for this critical utility infrastructure-based safety work. SCE states that existing authorizing legislation (i.e., AB 1054 and AB 913) currently allows for the securitization of wildfire-related O&M expenses, which SCE believes is an appropriate tool to use as conditions warrant to reduce the near-term rate impacts to customers.

SDG&E states it is still considering whether certain wildfire mitigation costs currently collected through rates could (or should) potentially be funded from outside sources.

Historical Legislative Policy 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. Legislative policy mandates for the 6-year period 2016 – 2021 are shown in Table 17, listed from the highest to lowest total cost in total electric revenue requirement equivalent.[115] This table shows program costs but does not calculate possible savings to the utility ratepayers; the CPUC details these costs and benefits in other reports. For example, while the Renewable Portfolio Standard (RPS) creates added costs, there is also a savings from avoided procurement of other generation, with savings increasing over time as renewables become less expensive. Similarly, benefits from IOU grid modernization deployment projects, and electricity and natural gas efficiency savings for the utilities the CPUC regulates are discussed in separate legislative reports.[116]

115 Revenue requirement as included in Advice Letters (AL): PG&E 6004-E-C; SCE 4590-E; SDG&E 3855-E.

116 *See* 2021 Costs and Cost Savings for the RPS Program (Padilla Report); California's 2020 Grid Modernization Report; and Report on Energy Efficiency Portfolio (2017 – 2019).

Table 17: Programs Mandated by California Statute, Electric Revenue Requirement in Rates, Six Year Total (2016 – 2021)

Code	Legislation	Program Name	Six Year Total 2016 - 2021 (in millions of dollars)			
			PG&E	SCE	SDG&E	Total
A	SB 1078, SB 350, SB 100	Renewable Portfolio Standard	12,802	13,506	4,012	30,320
I	AB 1X	Department of Water Resources Bond	2,028	2,023	450	4,501
A	SB 350, AB 1330, AB 802, AB 32, AB 1890	Energy Efficiency	1,642	1,328	544	3,514
A	AB 32	Greenhouse Gas Compliance Cost	463	1,833	212	2,507
A	Public Utilities Code § 2790, § 382; AB 327, AB 2857, SB 580, AB 2140	Energy Savings Assistance Program / California Alternate Rates for Energy Program	905	371	739	2,015
A	Public Utilities Code § 399.8; AB 1890	Electric Program Investment Charge	515	427	90	1,032
N	AB 1054	Wildfire Fund Charge	403	412	90	906
A	SB 1414, AB 793	Demand Response	279	349	96	724
A	AB 970, SB 700, AB 1144	Self-Generation Incentive Program	299	283	92	675
A	Public Utilities Code § 431-432	CPUC Fee	288	295	68	651
A	AB 1X	Total Rate Adjustment Component	0	0	613	613
A	AB 693	Solar on Multifamily Affordable Housing	203	225	48	476
A	SB 859	Tree Mortality Non-Bypassable Charge	166	113	38	316
N	AB 841	School Energy Efficiency Stimulus Program	78	101	41	219
A	SB 350, AB 1082, AB 1083, AB 628	Transportation Electrification Programs	99	59	49	206

A	AB X1 6	Hazardous Substance Memorandum Account	183	16	3	202
A	Public Utilities Code § 2791-2799	Mobile Home Park Program	82	84	22	188
A	SB 1, AB 217, AB 2723	California Solar Initiative - Multifamily Affordable Solar Housing / Single-Family Affordable Solar Homes	48	121	11	181
I	SB 1, AB X1 15	New Solar Homes Partnership Program	57	46	10	113
-	Other	Other	215	178	21	414
A	AB 32	Climate Credit from GHG Cap & Trade Revenues	(2,166)	(2,131)	(498)	(4,796)
		Six Year Total	**18,587**	**19,640**	**6,752**	**44,979**
Code Legend: A = Active (i.e. revenue requirement change in 2021); N = New; I = Inactive (i.e. no revenue requirement change in 2021)						

Several of the revenue requirements in the above table with public policy priorities are collected through the Public Purpose Program (PPP) rate component, including Energy Efficiency program funds[117] and the Electric Program Investment Charge (EPIC) program.[118] These programs generally seek to leverage upfront investments into future benefits such as reduced energy usage or accelerated decarbonization efforts. The CARE program revenue requirements presented in Table 17 do not include the surcharge on non-exempt customers to fund the line-item CARE discount.[119] Those costs are presented in the following section.

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 rates to qualifying low-income households with incomes at or below 200 percent of the Federal Poverty Guideline. 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

[117] Energy Efficiency program funds included Energy Savings Assistance (ESA) program funds. The ESA program provides no-cost in-home weatherization services, energy efficiency measures, and energy education to help eligible low-income households conserve energy, reduce energy costs and improve their health, comfort, and safety.

[118] EPIC is a state-level public interest electricity research, development, and deployment program driving investments in emerging technologies to ensure the state's energy policy goals are achieved.

[119] The line item CARE discount is the amount deducted as a credit on CARE customer bills.

monthly utility bills. The CARE program also seeks to provide financial assistance solely in the interest of lowering customers' bills, and currently provides a rate discount ranging from approximately 30 percent to 35 percent on electric bills and 20 percent on natural gas bills.[120]

Legislative and Regulatory Background

The 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 is today.[121] As economic hardship for California residents has increased over the course of the COVID-19 pandemic, participation in CARE has increased with approximately one million new customer accounts added between March and December 2020 and an additional 760,000 new accounts in 2021. In 2021, the program provided approximately $1.9 billion in annual subsidies and served approximately 5 million low-income customers statewide.[122]

Costs in Rates

CARE program costs are three-fold and are collected from all retail[123] non-exempt residential and all non-residential customer classes:

- The surcharge on non-exempt customers to fund the line-item CARE discount (i.e., the amount deducted as a credit on CARE customer bills)
- The rate exemptions collected from non-exempt customers in the form of higher rates to collect certain revenue not collected from exempt customers (i.e., the rate exemptions that CARE customers receive for the CARE surcharge itself and other rate exemptions such as the Wildfire Fund Charge exemption)
- Program administration expense

Table 18 shows the sums of these electric costs for each IOU.[124]

---

120 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.

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

122 Some customers are enrolled in more than one program; for example, SCE for electricity and SoCalGas for natural gas. *Source*: 2021 IOU ESA-CARE Monthly Reports, posted to Docket A.19-11-003.

123 All retail includes bundled and unbundled customers.

124 Amounts represent program costs incurred per year, which may be different from amounts billed to customer for the program year, due to regulatory timing differences.

Table 18: PG&E, SCE, and SDG&E Total CARE Program Costs (Electric, Program Years 2016 – 2021, $ millions)

	2016	2017	2018	2019	2020	2021
PG&E	$597.2	$635.9	$597.2	$607.7	$766.5	$882.8
SCE	$438.9	$451.1	$452.7	$421.5	$589.7	$721.0
SDG&E	$116.2	$121.4	$135.6	$129.0	$149.1	$180.5
Total	$1,152.3	$1,208.4	$1,185.5	$1,158.2	$1,505.3	$1,784.3

A higher CARE subsidy does not result in a higher revenue requirement for the utility as the collection from Non-CARE customers funds the effective discount to CARE customers; this collection increases the rates that Non-CARE customers pay. Table 19 through Table 21 show for each IOU the estimated 2021 CARE program funding bill impacts for bundled Non-CARE customers.[125]

Table 19: PG&E CARE Program Portion 2021 Monthly Bill, Bundled Non-CARE Residential and Non-Residential Customers (Year-End, $/month)

	PG&E 2021 Total Bill ($/month)	CARE Program Portion ($/month)	CARE Program Portion (%)
Non-CARE Residential	$153	$7	5%
Small Commercial	$283	$13	5%
Medium Commercial	$2,648	$148	6%
Agricultural	$1,803	$90	5%
Large / Industrial	$141,758	$11,086	8%

[125] Customer billings may not reflect program costs for the calendar year shown in Table 18 due to regulatory timing differences. These differences generally correct in the succeeding program year as balancing account balances are trued-up. Bills are for illustrative purposes only.

Table 20: SCE CARE Program Portion of 2021 Monthly Bill, Bundled Non-CARE Residential and Non-Residential Customers (Year-End, $/month)

	SCE 2021 Total Bill ($/month)	CARE Program Portion ($/month)	CARE Program Portion (%)
Non-CARE Residential	$135	$8	6%
Commercial	$6,815	$355	5%
Agricultural	$20,549	$1,365	7%
Large Industrial	$731,970	$56,050	8%

Table 21: SDG&E CARE Program Portion of 2021 Monthly Bill, Bundled Non-CARE Residential and Non-Residential Customers (Year-End, $/month)

	SDG&E 2021 Total Bill ($/month)	CARE Program Portion ($/month)	CARE Program Portion (%)
Non-CARE Residential[126]	$107	$4	4%
Commercial	$324	$18	6%
Agricultural	$1,112	$58	5%
Large Industrial	$6,073	$568	9%

Public Purpose Program-related Stakeholder Proposals in the 2022 Affordability Proceeding En Banc

Several ideas with respect to eliminating non-exempt customers cost responsibility for social programs collected through the PPP rate component were presented at the CPUC 2022 Affordability Proceeding[127] En Banc.[128] Additionally, the IOUs were asked to comment on specific ideas presented at the En Banc as part of their recommendations to limit cost and rate increases consistent with the state's energy and environmental goals for reducing greenhouse gases, as

---

126 Based on annual average usage of 366 kWh/month.

127 *See* A.18-07-006.

128 *See* 2-28-22 Hearing and 3-1-22 Hearing.

required by Public Utilities Code Section 913.1.[129] The points summarized here reflect the comments made by stakeholders and do not include any evaluation of the recommendations, as these proposals are still being considered by the CPUC in a formal proceeding.

Melissa Brandt, Vice President of Public Policy and Deputy General Counsel, East Bay Community Energy (EBCE): Ms. Brandt expressed concern for customers who are not eligible for a low-income program such as CARE but who are still low-income due to high cost of living (with housing costs in certain areas of the State particularly high) and who are paying certain PPP costs on a volumetric basis[130] i.e., paying just as much as customers who have higher incomes. She proposed that legislative action and a long-term funding source are needed to move certain PPP costs such as CARE program costs out of utility rates and into State funding sources.[131] State funds include the State General Fund, which may be problematic as costs for programs such as CARE currently don't qualify for surplus dollars funding and long-term funding is not assured.[132]

Arjun Makhijani, President, Institute for Energy and Environmental Research, and Energy Expert for the Just Solutions Collective: Mr. Makhijani noted that the CPUC's Percentage of Income Payment Plan (PIPP) program[133] is in the pilot stage. He commented on the benefits of a full-scale PIPP program for low-income customers to lower household energy burden, but noted that this should be considered together with non-ratepayer funding due to PIPP program's social safety net nature. He said that energy burden must go down for low-income customers as part of a well-managed clean energy transition.[134]

IOU Comments on En Banc Topics: The IOUs were asked to comment specifically on implementing a PIPP program at scale, with additional comments on potential sources of non-ratepayer funds to fund a full-scale program. The IOUs also commented they are working together to bring forward a legislative bill proposal that would remove public purpose program funding from the electric bill. This legislation would create a fund in the State Treasury and require state or other non-customer funding for these programs.

---

[129] The comments provided by the IOUs are subject to change as more formal comments are submitted in the Affordability proceeding and as issues are considered in this and related proceedings. Full responses can be found in the links provided in Appendix A.

[130] The CARE surcharge and the Wildfire Fund rate exemption comprise most of total CARE program costs and are collected on an equal-cents-per-kilowatt basis.

[131] This sentiment was also expressed by Scott Crider (SDG&E). While both Ms. Brandt and Mr. Crider talked about state funding of PPP costs in general, the emphasis in this report is on CARE program PPP costs in particular.

[132] Ms. Brandt (EBCE) does not quantify the rate reduction or bill reduction for customers who are not exempt from CARE program funding (i.e., all Non-CARE residential customers and all other non-residential customers) if funding is moved to non-ratepayer funding sources, however, Table 19 through Table 21 show this amount would save Non-CARE residential customers about $48/year (SDG&E) to about $96/year (SCE).

[133] A PIPP program allows the utility to cap a customer's utility bill at a percentage of their monthly income.

[134] This sentiment was also expressed by Melissa Brandt (EBCE). Specifically, rates should incentivize the fuel switch to electric.

The IOUs were reluctant to comment on a PIPP program at scale, noting that the PIPP pilot proposal has not yet been approved.[135] PG&E stated the PIPP pilot and evaluation will provide insights to help determine whether it should be administered at scale, and if so, what the associated costs may be, and that it would support exploring different approaches to funding such a program at that time, which could include non-ratepayer sources. SCE indicated it is supportive of accessing external sources of funding, such as California's General Fund, to support any future iterations of PIPP beyond the pilot. SDG&E expressed concerned with PIPP program funding sources, adding that even though the pilot program is limited to 1,000 customers, SDG&E estimates a wide range of subsidy for participant customers which will ultimately be shouldered by non-participant ratepayers. For the pilot's 48-month duration, SDG&E has estimated an electric subsidy of $650,000-$8,300,000, which equates to a subsidy of approximately $162,500-$2,075,000 per year.

Regarding a potential legislative proposal that would remove public purpose program funding from the electric bill, SCE indicated it is supportive of continuing to seek opportunities to utilize non-ratepayer funding for certain public purpose programs and other activities that are not specifically related to a utility's cost of service but are paid today through electric rates. For example, the program costs and subsides associated with SCE's income-qualified CARE and FERA programs would be appropriate to fund with state funds, given that they provide valuable assistance for income-constrained customers, reflecting a beneficial public good beyond the utilities' operations and services.

However, SCE cautions the operational complexity of accessing the state's General Fund to offset customer costs for certain programs should be considered to ensure that any adjustments to existing programs and costs do not create new risks or points of failure, or amplify levels of administrative burden, any of which could ultimately result in less efficient and more costly services. As such, SCE states the most effective approach would be to leverage existing approval processes and cost recovery mechanisms through the CPUC and other state agencies to access non-ratepayer funds and offset customer costs where appropriate. For example, the CPUC could approve an offset to SCE's already-authorized funding for any amounts made available by the California legislature. In addition, for any funding SCE receives, the existing cost recovery mechanisms are already designed to allow for state funding to offset authorized revenue to be collected from customers (e.g., through a credit to a balancing account, reducing the amount recovered through customers' rates).

Net Energy Metering Tariffs Cost Considerations

Perhaps no other energy program currently highlights the need to marry clean energy and equity goals more than the Net Energy Metering (NEM) tariffs available to IOU customers with behind-the-meter renewable electrical generation facilities, such as rooftop solar photovoltaic (PV) systems,

---

[135] In February 2002, the IOUs submitted Tier 3 Advice Letters to implement each IOU's PIPP Pilot proposal.

with or without storage. The Public Utilities Code requires that NEM achieve various equity-related aims[136] while also ensuring "that customer-sited renewable distributed generation continues to grow sustainably…"

Legislative and Regulatory Background

California's NEM tariffs started in 1997, prompted by Senate Bill 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. California's first NEM design, now colloquially known as "NEM 1.0," was revised in 2016 via Decision (D).16-01-044[137] per Assembly Bill (AB) 327 (Perea 2013). Customers on the "NEM successor tariff," or "NEM 2.0," pay for their cost to connect to the grid, take service on a time-of-use (TOU) rate plan,[138] and pay certain non-bypassable charges[139] 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.

The CPUC opened a new proceeding in August 2020 (Rulemaking (R.)20-08-020) to revisit the NEM 2.0 tariffs.[140] A proposed decision (PD) to modernize NEM through a new standard net billing tariff was issued on December 13, 2021. One objective of the PD, among many, is to better align the tariff with statutory language requiring the CPUC to ensure the tariff's benefits to all customers and the electrical system approximately equal its costs while also ensuring that behind-the-meter distributed generation continues to grow sustainably. [141] The PD also would promote battery storage, reduce greenhouse gas emissions by reducing demand and increasing exports during peak grid demand periods, and create an equity fund to encourage deployment of distributed energy resources by customers in low-income, disadvantaged, and Tribal communities. At the time of writing, the PD has not received a vote and the CPUC is evaluating party and public comment.

Cost Shift Equity Considerations

All residential non-NEM or non-participating customers, including CARE customers, shoulder an additional rate burden as a result of the cost shift from NEM customers. Summarizing the record in the current NEM proceeding, the PD notes that estimates of the annual cost shift for 2021 range

---

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

137 *See* D.16-01-044.

138 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.

139 D.16-01-044 lists the relevant non-bypassable charges as Public Purpose Program Charge; Nuclear Decommissioning Charge; Competition Transition Charge; and Department of Water Resources bond charges.

140 *See* documents in docket for R.20-08-020.

141 *See* Public Utilities Code §2827.1(b)(1) and §2827.1(b)(4).

from $1 billion to $3.4 billion.[142] Most of this burden is shifted to non-NEM customers, since their population is larger than the NEM customer population, and much of NEM customers' bills are offset by the NEM systems.[143] Some of the equity concerns related to the NEM cost shift include the following:

- As of December 2021, PG&E had approximately 588,000 residential NEM customers and 1.4 million CARE customers. Of these CARE customers, only about 7 percent are NEM participants, meaning about 1.3 million, or approximately 93 percent of CARE customers, do not participate in NEM and therefore bear the cost responsibility of compensating NEM customers.

- SCE had, as of December 2021, approximately 425,000 residential NEM customers and 1.4 million CARE customers. Of these CARE customers, only about 5 percent participate in NEM, meaning over 1.3 million CARE customers, or about 95 percent, shoulder the additional cost burden from NEM customers.

- As of December 2021, SDG&E had approximately 205,000 residential NEM customers and 320,000 CARE customers. Of these CARE customers, only about 5 percent are NEM participants, meaning that 95 percent of CARE customers do not participate in NEM and therefore shoulder additional cost burden from NEM customers.

Income-Graduated Fixed Charge Proposal in the 2022 Affordability Proceeding En Banc

With respect to limiting costs and rate increases, stakeholders presented several novel approaches at the CPUC 2022 Affordability Proceeding[144] En Banc, held February 28, 2022 and March 1, 2022.[145] Additionally, the IOUs were asked to comment on specific ideas presented at the En Banc as part of their recommendations to limit cost and rate increases consistent with the state's energy and environmental goals for reducing greenhouse gases, as required by Public Utilities Code Section 913.1.[146] The points summarized here reflect the comments made by stakeholders and do not

---

142 Proposed Decision Revisiting Net Energy Metering Tariff and Subtariffs, Finding of Fact 197, p. 173.

143 *See* Public Advocates Office Opening Testimony (pp. 2 – 17).

144 *See* A.18-07-006.

145 *See* 2-28-22 Hearing and 3-1-22 Hearing.

146 The comments provided by the IOUs are subject to change as more formal comments are submitted in the Affordability proceeding and as issues are considered in this and related proceedings. Full responses can be found in the links provided in Appendix A.

include any evaluation of the recommendations, as these proposals are still being considered by the CPUC in a formal proceeding.

Meredith Fowlie, Faculty Director, Energy Institute at Haas, UC Berkeley: While not directly addressing NEM-related cost shifts, the income-based fixed charge proposal[147] Dr. Fowlie presented may help alleviate rate pressure on lower-income and middle-income customers, particularly those in high usage areas such as the Central Valley, San Joaquin Valley, and Coachella Valley. This is because mapping sliding-scale fixed charges to stratified incomes produces a lower volumetric ($/kWh) rate than a rate structure without a fixed charge. The income-based fixed charge is designed to address concerns about affordability and equity by shifting cost recovery away from low-income households. Administrative details such as how income would be verified could present implementation challenges.[148]

IOU Comments on En Banc Topics: The IOUs were asked to comment specifically on implementing an income-based fixed charge with the amount charged progressively increasing for higher income households.

The IOUs support a fixed charge, acknowledge the statutory maximum for a default residential fixed charge, and recommend that, as an initial step,[149] the CPUC consider an approach that uses the income gradation currently existing in rates. When fixed charges for CARE and FERA[150] are taken together with a non-CARE fixed charge, this structure represents a basic three-level income-based fixed charge approach. The IOUs list challenges and complexities of the income verification aspect of an income-based fixed charge that uses tax or other income information sources.

PG&E believes major changes are needed to start recovering significant portions of costs in fixed charges. PG&E and SDG&E noted half or more of their electric costs are fixed, but are disproportionately recovered through volumetric rates. PG&E points out that in the absence of reasonable fixed charges that collect at least a portion of utility fixed costs, higher-usage customers are forced to pay disproportionate shares of fixed costs and thus subsidize lower-usage customers. SDG&E further notes a fixed charge rate design should not consider net electricity usage alone as, increasingly, low usage does not equate to low income with most of the very low usage customers also being NEM customers.

PG&E posits that there could be other ways to differentiate fixed charges that are based on cost of service, such as variations in connection costs. For example, charging a higher fixed charge for

---

147 For more details, *see* https://haas.berkeley.edu/wp-content/uploads/WP314.pdf.

148 Mohit Chhabra (NRDC) touched on a similar type of income-based fixed charge as a means to overcome the regressive nature of a flat fixed charge for low-income and low-consumption households.

149 Legislative action is required to change the statutory maximum for a default residential fixed charge.

150 California Alternative Rates for Energy (CARE) and Family Electric Rate Assistance (FERA) customers receive bill discounts.

single-family dwellings (with higher amperage services and longer service drops) than multi-family dwellings (with more meters per service drop).

Historical Transportation Electrification Program Costs

Clean energy transportation electrification legislative mandates along with private sector innovation will propel the transition to a fully electrified transportation sector. With California's aggressive goals for transportation electrification (TE) over the next decade, significant upgrades to the distribution grid will be necessary to accommodate charging demand. While there is an ongoing policy discussion regarding the extent of ratepayer responsibility for TE costs, 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.[151] SB 350 directed the CPUC to require the IOUs to submit applications for programs that leverage ratepayer funding to support electric vehicle (EV) adoption.[152] 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 and 250,000 installed publicly available EV charging stations and 200 publicly available hydrogen fueling stations in the state by 2025.[153]

In September 2020, Governor Newsom pushed these state goals further by issuing Executive Order N-79-20 to require all in-state sales of new passenger vehicles be zero-emission by 2035. The Executive Order also set a further goal that 100 percent of medium- and heavy-duty vehicles in the state be zero-emission by 2045, and 100 percent of drayage trucks must be zero-emission by 2035. Furthermore, the Executive Order sets a state goal to transition to 100 percent zero-emission off-road vehicles and equipment by 2035, where feasible.

Additionally, AB 841 (Ting, 2020) was signed into law in September 2020. This bill 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

---

151 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.

152 Such as multi-unit dwellings, workplaces, destination centers, disadvantaged communities, and low/medium income residential communities.

153 Executive Order (E.O.) B-48-18.

needed to charge EVs[154] 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 2021[155] and the exemption to Rules 15 and 16 for residential customers was approved in December 2021.[156]

Costs in Rates

As of fourth quarter 2021, the CPUC has authorized the large electric IOUs to spend approximately $1.8 billion on EV charging infrastructure to support the state's TE goals and is considering another application from PG&E for approximately $275.8 million in TE funding.[157] Out of the authorized IOU funding to date, $316 million has been spent by PG&E, SCE, and SDG&E and $1.21 billion is still available for TE investment. Total TE costs placed in rates[158] between 2017 and 2021 are approximately:

- PG&E: $152 million
- SCE: $113 million
- SDG&E: $115 million

Figure 15 shows for each IOU the relative share of the total operating expense and total capital-related revenue requirement[159] reflected in 2017 - 2021 rates corresponding to each IOU's transportation electrification program costs. Operating expense revenue requirement includes balancing accounts which may reflect negative (over-collected) balances.[160]

---

[154] 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.

[155] *See* Resolution E-5167 (large IOUs) and Resolution E-5168 (small and multi-jurisdictional utilities).

[156] *See* D.21-12-033.

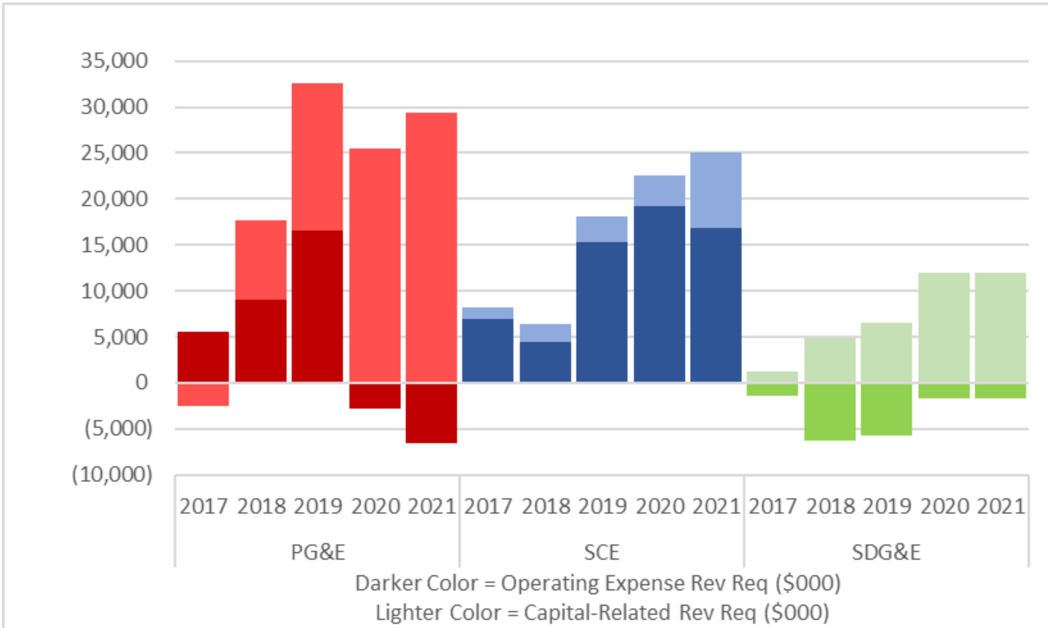
[157] PG&E's proposed EVC 2 is an extension of PG&E's fully-subscribed and successful Electric Vehicle Charge Network (EVCN) program (approved in D.16-12-065) and ongoing EV Fast Charge program (approved in D.18-05-040). PG&E filed its EVC 2 Application and Testimony in October 2021.

[158] Total TE costs placed in rates includes all program capital and operating expense charged to a program (direct costs, overheads, etc.) as reflected in rates implementation advice letters.

[159] 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 expenditures explanation earlier in this chapter.

[160] A capital-related amount may be negative due to first year depreciation flowback.

Figure 15: PG&E, SCE, and SDG&E Transportation Electrification Programs Revenue Requirement in Rates (2017 – 2021, Year-End, $ millions)



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. Table 22 shows 2021 TE program bill impacts:[161]

Table 22: PG&E, SCE, and SDG&E TE Programs Portion of 2021 Monthly Bill, Bundled Residential Customers (Year-End, $/month)

	Total Bill ($/month)	TE Program Portion ($/month)	TE Program Portion (%)
PG&E	$135.13	$0.19	0.1%
SCE	$135.48	$0.24	0.2%
SDG&E	$183.21	$1.14	0.6%

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 recently

161 Year-end 2021 rates in effect. Typical Non-CARE customer using 500 kWh (PG&E Climate Zone S, SCE Climate Zone 9, and SDG&E Inland Climate Zone). Bills are for illustrative purposes only.

issued CEC Staff report *Assembly Bill (AB) 2127 Electric Vehicle Charging Infrastructure Assessment*, which notes that 1.5 million chargers will be needed by 2030 to support Governor Newsom's goals for light-duty vehicles. 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 ratepayer, private, and public (e.g., state/federal grant) funding.[162] 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 for 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;[163] and 2) Low Carbon Fuel Standard (LCFS), credit revenue generated from EVs that is used in many cases to support additional charging infrastructure.

Transportation Electrification-related Stakeholder Proposals at the 2022 Affordability Proceeding En Banc

Several ideas with respect to limiting transportation electrification-related costs and rate increases were presented at the CPUC 2022 Affordability Proceeding En Banc held February 28, 2022 and March 1, 2022.[164] The points summarized here reflect the comments made by stakeholders and do not include any evaluation of the recommendations, as these proposals are still being considered by the CPUC in a formal proceeding.

Mark Toney, Executive Director, The Utility Reform Network: Dr. Toney proposed a point-of-sale (POS) surcharge be levied on internal-combustion engine (ICE) vehicle sales as an alternative to either ratepayer or taxpayer funding of transportation electrification programs, highlighting the cost-causation basis of this proposal as it aligns with consumers who are choosing to increase greenhouse gas emissions by purchasing ICE vehicles. Some of the money collected should go to installing charging infrastructure in multi-unit dwellings.

Catherine Yap, Principal, Barkovich & Yap: Ms. Yap emphasized that it is unfair for ratepayers to fund transportation electrification and utilities shouldn't be involved in this type of investment as it is market-driven and not inherently part of the natural monopoly that exists for utility companies with respect to delivering electricity. EV charging infrastructure in apartment buildings should be funded

---

162 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.

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

164 *See* 2-28-22 Hearing and 3-1-22 Hearing.

by State surplus funding to incentivize construction, which should be done without utility involvement.

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.

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[165] 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 Figure 16 through Figure 18. Each class shows the same upward trend as the system average rate over this period, with residential and small business 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 (higher average rates than system starting in 2019).[166] Residential and small business customers generally have higher rates than larger non-residential customers with the exception of SCE medium-sized business customers (higher average rates than system).

[165] Bundled IOU customers receive all services — generation, transmission, and distribution services — from the IOU.
[166] 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 16: PG&E Bundled System Average Rate By Class, Nominal Rates in Effect January 1[167]
(¢/kWh)

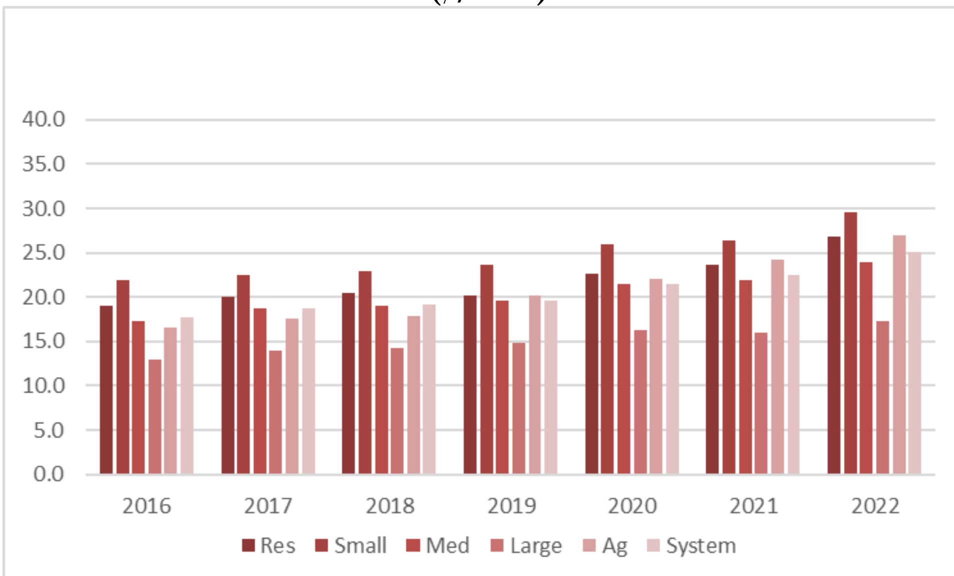


Figure 17: SCE Bundled System Average Rate By Class, Nominal Rates in Effect January 1[168]
(¢/kWh)

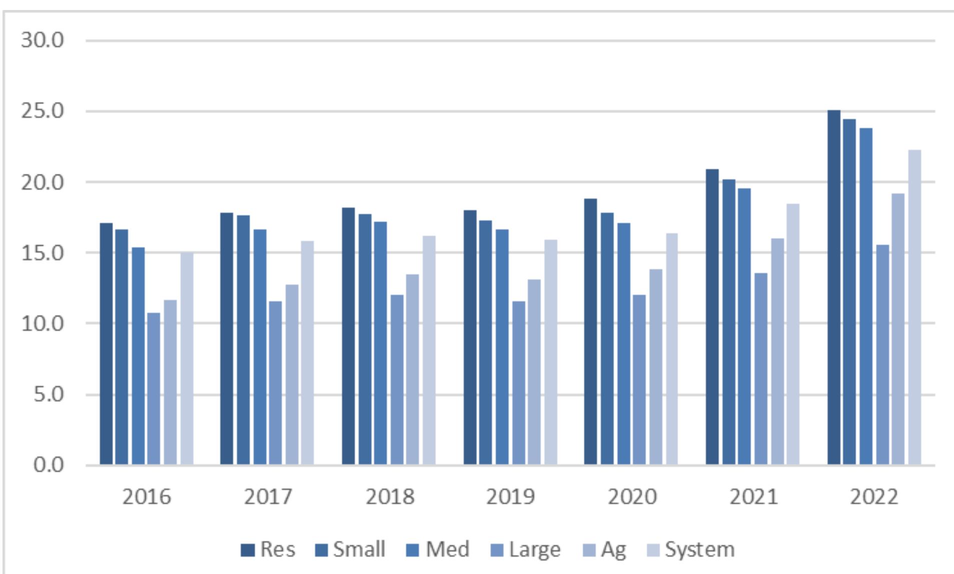


Figure 18: SDG&E Bundled System Average Rate By Class, Nominal Rates in Effect January 1[169] (¢/kWh)

Bundled Residential Average Rate

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 residential class and residential class forecasted sales are used in the numerator and denominator, respectively. Residential tariffs are then designed to collect the revenue requirement reflected in the RAR.

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

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

[168] 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.

[169] Class-level rates not associated with any specific rate schedule.

Figure 19 through Figure 24 show each IOU's bundled residential revenue requirement and forecasted sales for the period 2016 to 2022 as well as the nominal bundled RAR and inflation-adjusted bundled RAR resulting from the revenue requirement and forecasted sales. Certain bundled residential data is considered confidential by SCE and SDG&E and has been labeled as such in the applicable figures. For the graphs showing inflation-adjusted rates, nominal rates trending below the black line 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.

The variance in Figure 19 between PG&E's nominal and inflation-adjusted bundled RAR widens starting in the year 2020. In Figure 20, from 2020 to 2022, the bundled RAR increases on an annual average basis of about 2 percent and bundled residential authorized forecasted sales decrease on an annual average basis of about 6 percent. Both of these countervailing effects cause increased bundled RARs.

Figure 19: PG&E Bundled Residential Average Rate, Nominal and Inflation-Adjusted, Rates in Effect January 1 ($/kWh)

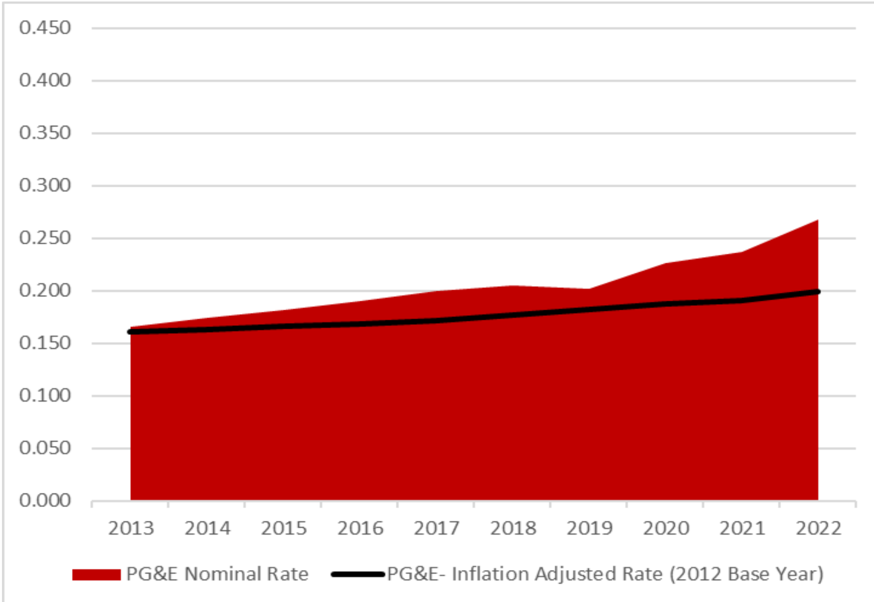


Figure 20: PG&E Bundled Residential Authorized Revenue Requirement (January 1, $ millions) and Forecasted Sales (January 1, GWh)

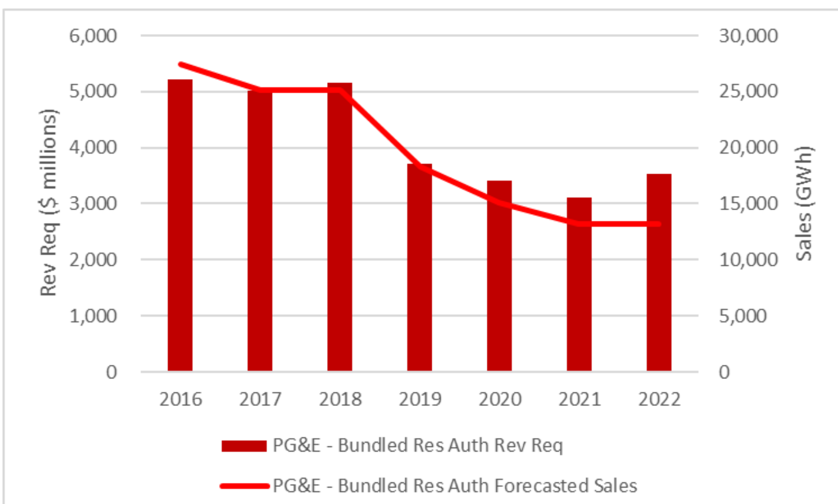
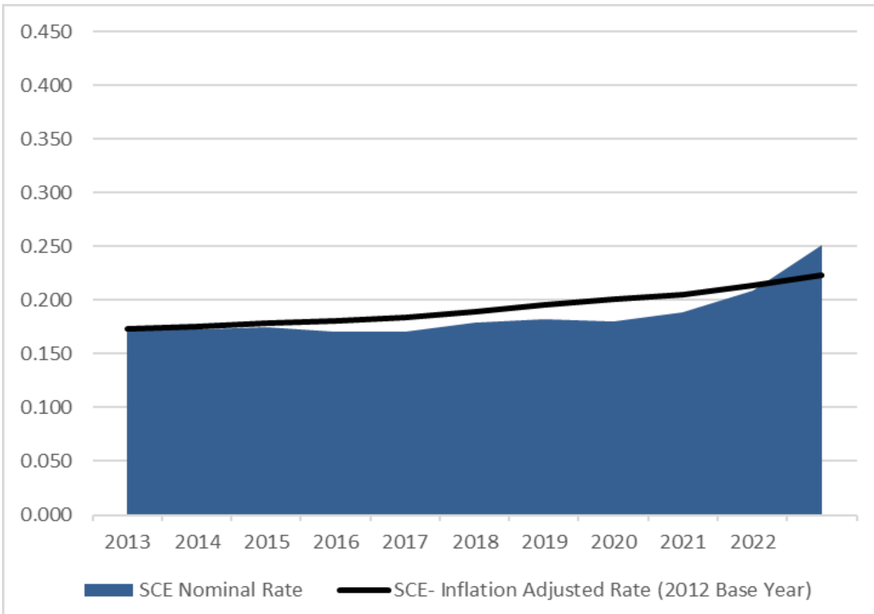


Figure 21 shows that SCE's bundled RAR appears to comport commendably well against inflation up until the year 2021. However, the data needed in Figure 22 to deconstruct this effect in the years 2021 and 2022 is not currently available due to confidentiality labeling.[170]

Figure 21: SCE Bundled Residential Average Rate, Nominal and Inflation-Adjusted, Rates in Effect January 1 ($/kWh)



[170] 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 Bundled Residential Authorized Revenue Requirement (January 1, $ millions) and Forecasted Sales (January 1, GWh)

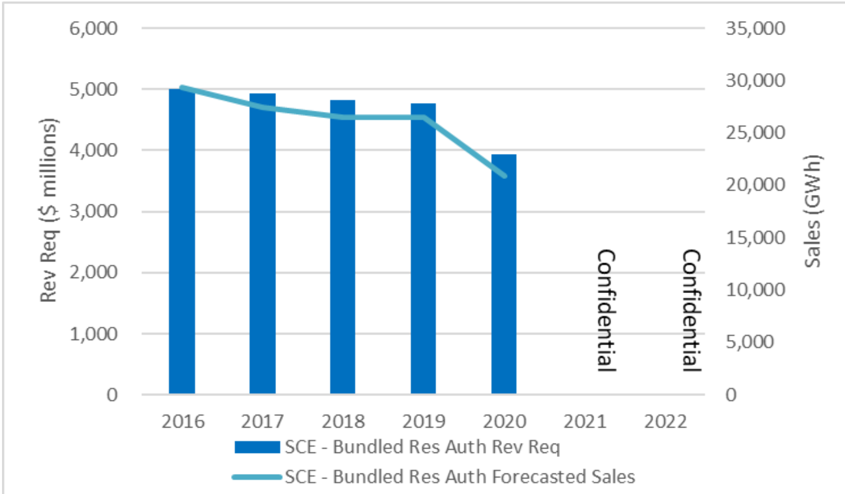


Figure 23 shows that SDG&E's bundled RAR has historically not maintained a close correlation with inflation. Since data not considered confidential is only available for the years 2016 – 2018, there is limited insight into the relative effects of increasing authorized revenue requirement and decreasing authorized sales forecasts as shown in Figure 24.[171]

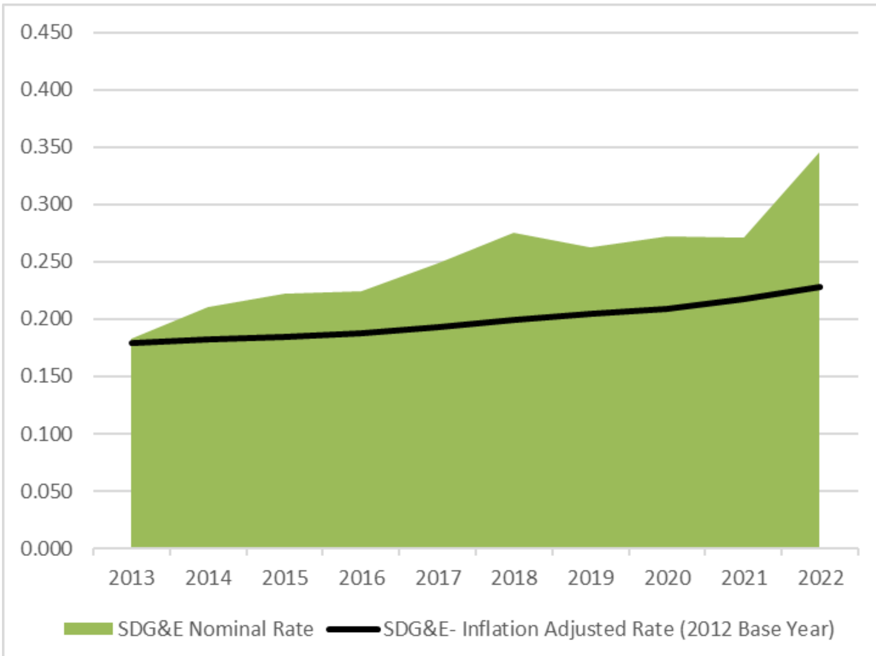
SDG&E has a larger share of customers investing in rooftop solar compared to PG&E and SCE. This high rate of photovoltaic (PV) adoption decreases the denominator (kWh sales) of SDG&E's bundled RAR, as customers are purchasing less electricity from the utility, although they may still be consuming the same amount from their PV system. While this decreased demand allows it 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,

---

[171] SDG&E declined to unmask bundled load forecasts for all years presented except as indicated. Confidentiality is claimed 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."

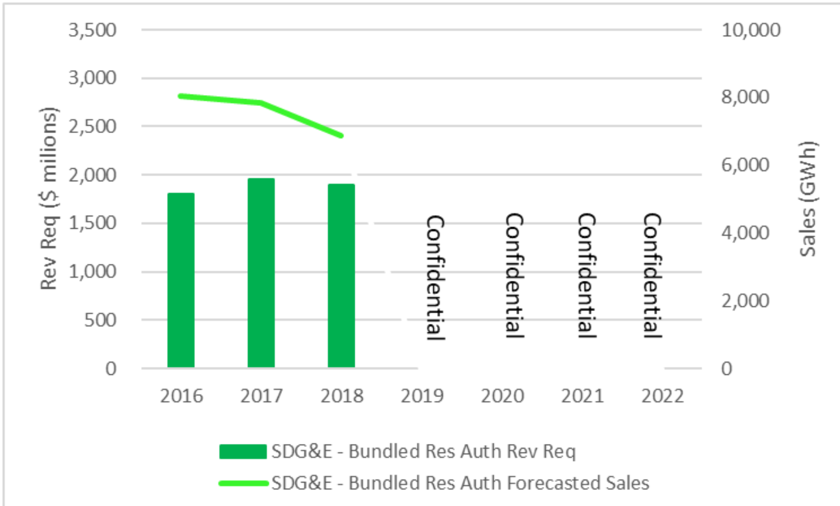
bills for NEM non-participant customers are about 20 percent higher than they would have been without current NEM tariffs.[172]

Figure 23: SDG&E Bundled Residential Average Rate, Nominal and Inflation-Adjusted, Rates in Effect January 1 ($/kWh)



172 *See* Chapter III, section "Net Energy Metering Tariffs Cost Considerations."

Figure 24: SDG&E Bundled Residential Authorized Revenue Requirement (January 1, $ millions) and Forecasted Sales (January 1, GWh)



Residential and Select Small Commercial Bundled 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 bill is largely driven by the volume of their 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**.[173] Residential usage tends to cluster around typical usage profiles, which vary by climate zone.[174] However, typical load profiles for non-residential customers can vary substantially, depending on their usage patterns in the commercial, industrial, or agricultural customer class.[175] Nevertheless, small business customers may be grouped by commercial customer group using standards such as the North American Industry Classification

[173] 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.

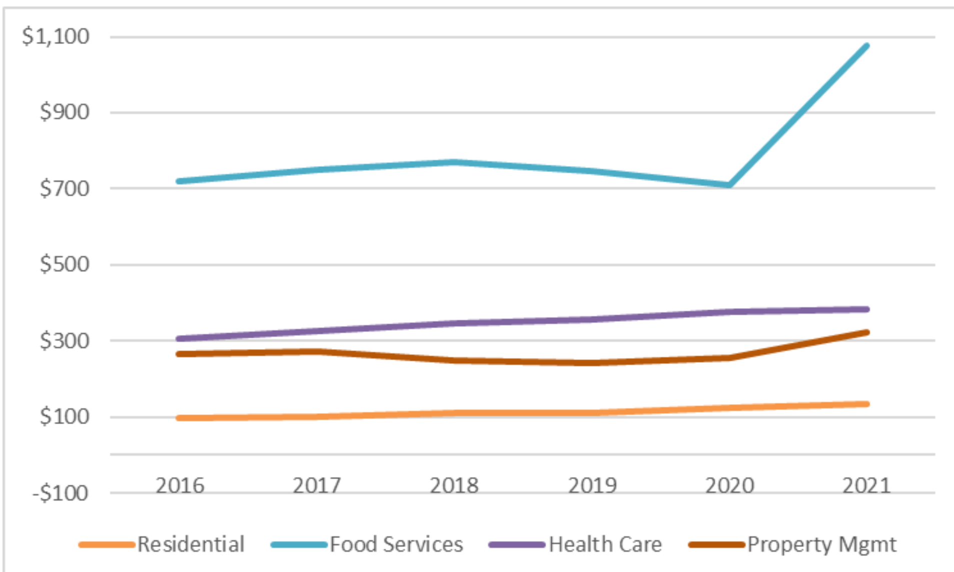
[174] Climate zones are drawn in each IOU's service territory based on climactic variation and are also known as baseline territories as defined by each IOU in its Preliminary Statements. For this analysis, residential average monthly usage for each IOU is based on average monthly usage reported for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

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

System (NAICS) in order to get a sense of typical usage for customers with the same industry code.[176]

Figure 25 through Figure 27show for each IOU typical bundled average monthly bills for residential customers[177] as well as for commercial customers representing Food Services and Drinking Places (NAICS 722), Ambulatory Health Care Services (NAICS 621), and Real Estate (Property Management, NAICS 531).[178] Bundled small business customers with industry subsector Food Services (NAICS 722) show typical average monthly bills in the mid- to high triple-digits, 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 slightly above $100.[179]

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



[176] 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.

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

[178] *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.

[179] Typical average monthly bills are for illustrative purposes only.

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

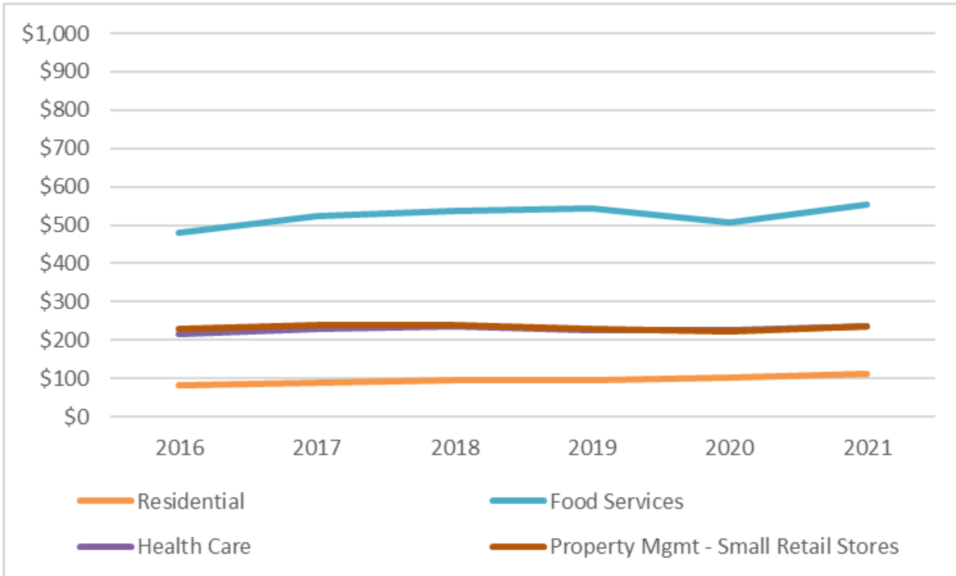
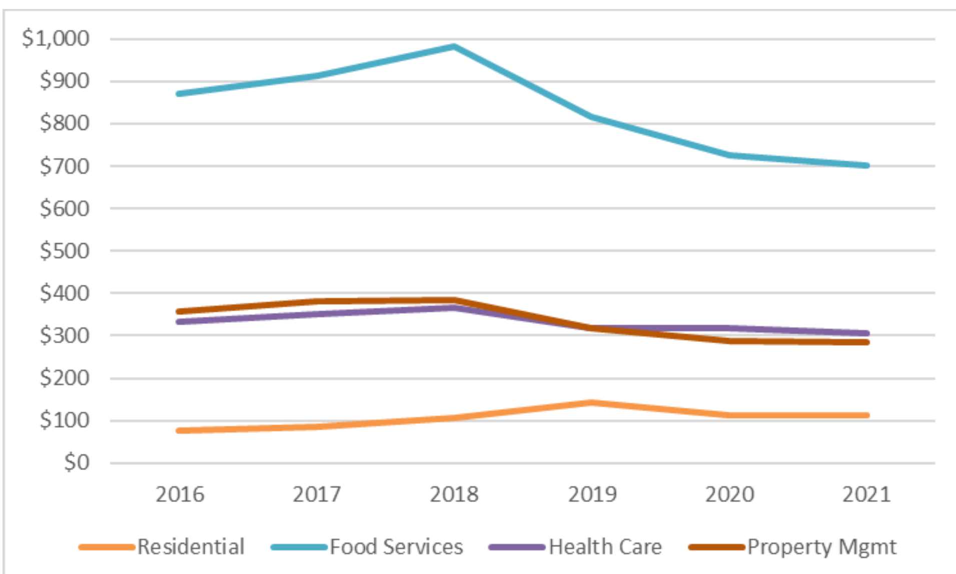


Figure 27: SDG&E Typical Bundled Average Monthly Bills, Residential and Select Small Commercial, Nominal Rates in Effect January 1 ($/Month)



III. Bundled Residential Customer Rates Forecast

Average electricity bills for PG&E bundled residential customers are forecast to rise at an annual average rate of about 9 percent, about 4 percent for SCE customers, and about 8 percent for SDG&E between now and 2025, implying that these households' energy bill will become less affordable if household incomes track the assumed inflation rate of 2.4 percent.

Historical Rates to Current Rates – Recent Increases

The CPUC is tracking electric and natural gas utility costs and rates to keep the public and policymakers apprised of recent trends.[180] Since the fourth quarter of 2021,[181] electric bundled residential average rates have increased approximately 18 percent for PG&E, 5 percent for SCE and 8 percent for SDG&E,[182] resulting in monthly bill increases as shown in Table 23.[183]

Table 23: Recent Increases in Residential Average Rates and Monthly Bills

	Residential Average Rates ($/kWh)			Average Residential Monthly Bills ($)		
	Q4-2021	Current	% Change	Q4-2021	Current	% Change
PG&E	0.248	0.292	17.7%	$140.24	$165.35	17.9%
SCE	0.244	0.256	4.9%	$135.48	$149.80	10.6%
SDG&E	0.321	0.345	7.5%	$149.26	$171.00	14.6%

These increases were largely driven by wildfire mitigation investments and operating expenses, including vegetation management and liability insurance, major price increases for natural gas power plant fuel, and increased electric transmission costs authorized by FERC.

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.

---

180 *See* CPUC Rate Change Advisories.

181 The last quarter of 2021 included the last rate increases of the year for each of the IOUs as follows: PG&E December 1, 2021; SCE October 1, 2021; and SDG&E November 1, 2021.

182 Current rates effective: March 1, 2022 for PG&E and SCE; January 1, 2022 for SDG&E.

183 Typical Non-CARE customer using 500 kWh (PG&E Climate Zone S, SCE Climate Zone 9, and 425 kWh (SDG&E Inland Climate Zone). Bills are for illustrative purposes only.

Forecasted Incremental Revenue Requirement and Projected Rate Impacts

As part of the Affordability proceeding,[184] the CPUC ordered PG&E, SCE, and SDG&E to each submit a quarterly cost and rate tracker tool (CRT) 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.[185] In addition to producing bundled[186] residential essential usage bills[187] for the affordability metrics, each IOU's CRT may be used to produce a short- to medium-term bundled residential cumulative rate forecast[188] to show overall rate trends.[189] The CRT can also use the rates forecast to project estimated bills for bundled residential customers at IOU climate zone level.[190]

The CRT models cumulative forecasted revenue requirement[191] and forecasted sales[192] information as provided by the IOUs to produce rates.[193] Forecasted incremental revenue requirement information is updated in the CRT for the duration of each cost recovery proceeding, to reflect the most-recent publicly-available revenue requirement.[194] 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 of certain types of costs is desired

---

184 *See* docket for (R.)18-07-006.

185 *See* D.20-07-032, Ordering Paragraph (OP) 1, p. 99.

186 Bundled customers take generation, distribution, and transmission services.

187 Essential usage bills (EUB) reflect essential service, which is the minimum amount of service measured by the metrics.

188 The forecasts produce cumulative rate impacts, assuming recovery of all pending rate requests for the current year and three additional years.

189 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.

190 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.

191 Includes balancing account balances and the California Climate Credit, also known as the Greenhouse Gas (GHG) Allowance Return. The GHG Allowance Return functions as revenue requirement reduction.

192 Forecasted sales are based on authorized sales forecasts or on sales forecasts requested in pending applications, if available.

193 Energy Division staff may modify the forecasts to reflect estimates for cost recovery applications not yet filed. Forecasts do not take into account future natural gas price spikes, which are difficult to predict.

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

such as wildfire-related costs, it may be difficult to break them out from other costs included in a proceeding, such as a GRC.[195]

Bundled Residential Average Rate Forecasts

Bundled residential average rate forecasts for the years 2022 – 2025 are shown in Table 24.[196] The forecasted rates are simple volumetric rates based on forecasted bundled residential revenue requirements and bundled residential sales forecasts. PG&E's, SCE's, and SDG&E's current electric CRT[197] 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 subject to material change as assumptions change. Further, forecasts are based on forward-looking estimates that are not historical facts.

Table 24: PG&E, SCE, and SDG&E Forecasted Bundled Residential Average Rates (nominal $/kWh)

	2022 - Act	2022	2023	2024	2025
PG&E Nominal Rate	$ 0.292	$ 0.306	$ 0.340	$ 0.353	$ 0.367
SCE Nominal Rate	$ 0.256	$ 0.262	$ 0.284	$ 0.284	$ 0.296
SDG&E Nominal Rate	$ 0.345	$ 0.356	$ 0.373	$ 0.412	$ 0.428

The percentage change in forecasted 2025 bundled residential rates over 2022 rates for each IOU are:[198]

- PG&E: 26 percent through 2025 or an annual average of 6.8 percent over this time period
- SCE: 16 percent through 2025 or an annual average of 4.2 percent over this time period
- SDG&E: 24 percent through 2025 or an annual average of 6.4 percent over this time period

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

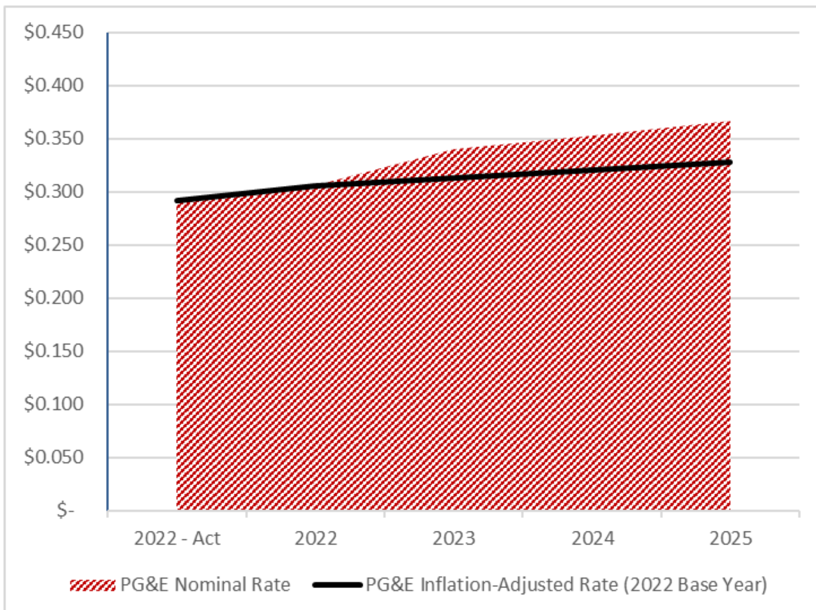
196 Cumulative rates, assuming recovery of all pending rate requests, are projected through year-end. Actual rates in effect during the first quarter of 2022 are included as a reference.

197 Current CRTs are for First Quarter 2022 (Q1-2022) with current rates effective March 1, 2022 for PG&E and SCE, and January 1, 2022 for SDG&E. PG&E and SDG&E CRT sales forecasts held at currently authorized sales forecasts; SCE CRT sales forecasts are estimated 2023-2025 sales forecasts.

198 Actual rates in effect at end of first quarter of 2022, with 3.75 years remaining through year-end 2025. PG&E rates forecast has been revised significantly upward since the rates forecast in the 2021 SB 695 Report due to higher revenue requirement than expected resulting from the filing of the 2023 GRC application since that time.

Inflation-adjusted rates for each IOU, based on 2022 actual rate as the base rate, show how the bundled residential rate forecast comports with forecasted inflation.[199] The bundled residential rates forecast with 2022 base year inflation-adjusted forecasted rates are shown in Figure 28 through Figure 30. Although inflation through 2025 has an estimated annual average rate that is higher than in previous periods, forecasted bundled residential rates continue to exceed counterfactual inflation-adjusted rates.

Figure 28: PG&E Forecasted Bundled Residential Rate, Nominal and Inflation-Adjusted ($kWh)



[199] Annual average inflation rate 2023 – 2025 forecasted at 2.4 percent. Projected rate inflators from U.S. Congressional Budget Office's "Update to the Budget and Economic Outlook: 2021 to 2031" (July 2021, p. 4), consumer price index for all urban consumers.

Figure 29: SCE Forecasted Bundled Residential Rate, Nominal and Inflation-Adjusted ($/kWh)

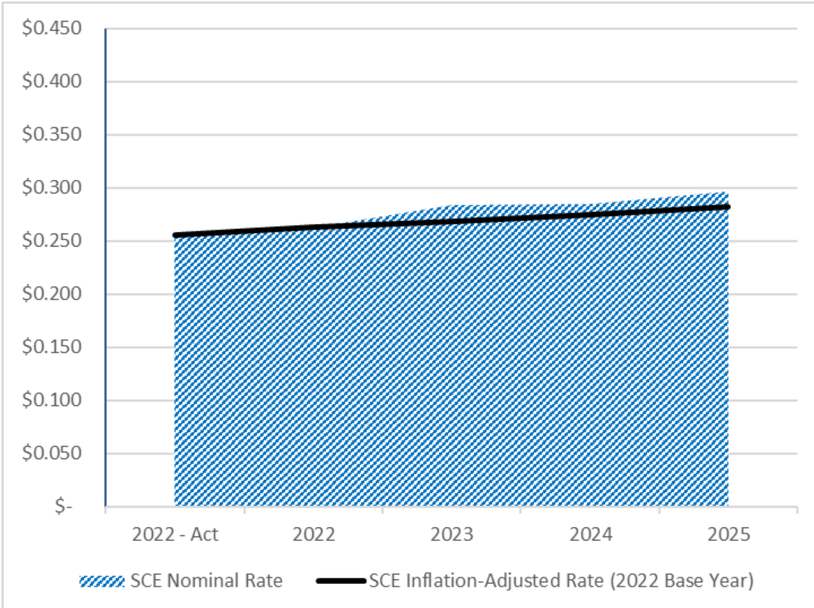


Figure 30: SDG&E Forecasted Bundled Residential Rate, Nominal and Inflation-Adjusted ($/kWh)

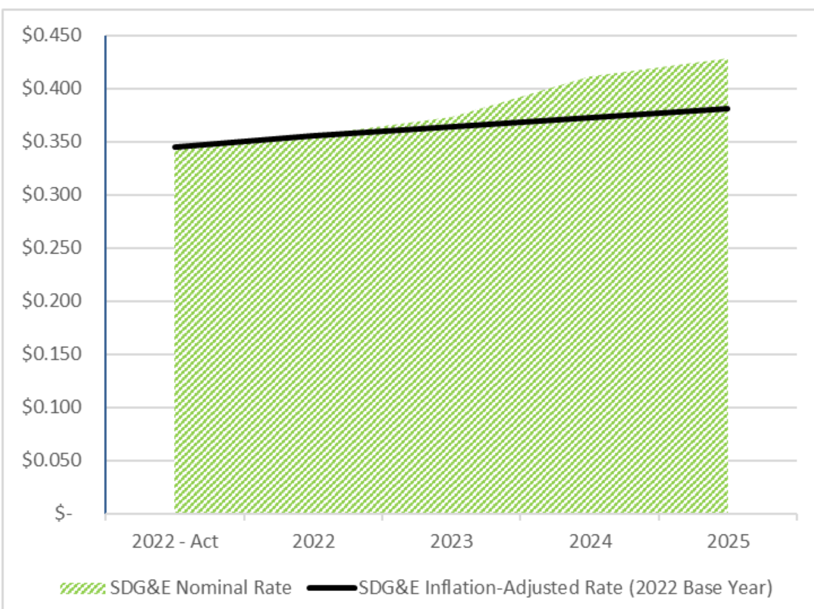


Table 25 shows the projected monthly bill increase resulting from the rates forecasts in Table 24 based on the usage amounts the IOUs use in their legal bill inserts – 500 kWh per month for PG&E and SCE, and 425 kWh for SDG&E.[200]

Table 25: Current and Projected 2025 Bills

IOU	Current Residential Average Monthly Bill	Projected 2025 Average Monthly Bill	Projected 2025 Annual Average Increase
PG&E	$165	$211	9.2%
SCE	$150	$168	4.0%
SDG&E	$171	$213	8.2%

Figure 31 through Figure 33 show a comparison of 2022 and 2025 bills based on average usage[201] for climate zones designated "moderate"[202] and "hot."[203] PG&E, SCE, and SDG&E CARE bills for customers in a hot climate zone in 2025 are projected to be about 28 percent, 12 percent, and 25 percent higher than similar bills in 2022, respectively, and when compared to CARE bills in a moderate climate zone in 2025, are projected to be about 34 percent, 63 percent, and 51 percent higher.[204] There may be areas within climate zones, particularly within hot climate zones, where CARE customers are experiencing acute affordability issues.[205]

200 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." Usage data here is that used in legal bill inserts for PG&E's 2023 GRC Phase I, SCE's 2021 GRC Phase II, and SDG&E's 2022 Energy Resource Recovery Account Forecast applications. Bills are for illustrative purposes only.

201 Average usage is based on Non-CARE and CARE recorded usage in 2021.

202 "Moderate" climate zones are also sometimes referred to as "warm" climate zones, as opposed to "cool" or "hot."

203 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. PG&E Climate Zone R includes Fresno County and other areas in the San Joaquin Valley; SCE Climate Zone 15 includes Riverside County and other areas in the Coachella Valley; and SDG&E Desert climate zone includes Imperial County and other areas in the Imperial Valley.

204 For Figure 33, SDG&E 2021 CARE recorded usage in a hot climate zone was high relative to Non-CARE usage (for both summer and winter seasons).

205 *See* Appendix C, "PG&E 2023 Affordability Metrics Testimony" for one such affordability analysis,

Figure 31: PG&E Monthly Bill for an Average Customer in a Moderate and a Hot Climate Zone (2022 Actual and 2025 Projected)

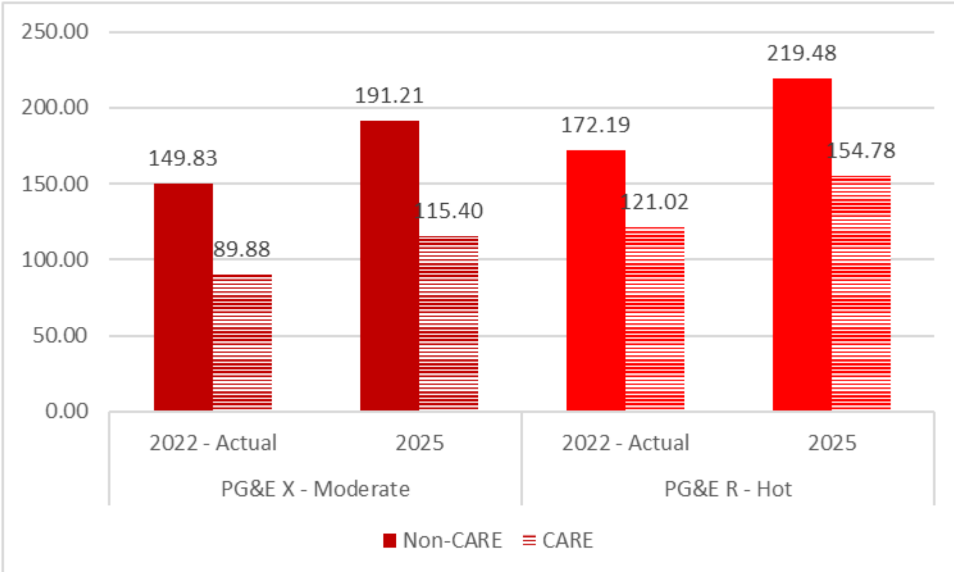


Figure 32: SCE Monthly Bill for an Average Customer in a Moderate and a Hot Climate Zone (2022 Actual and 2025 Projected)

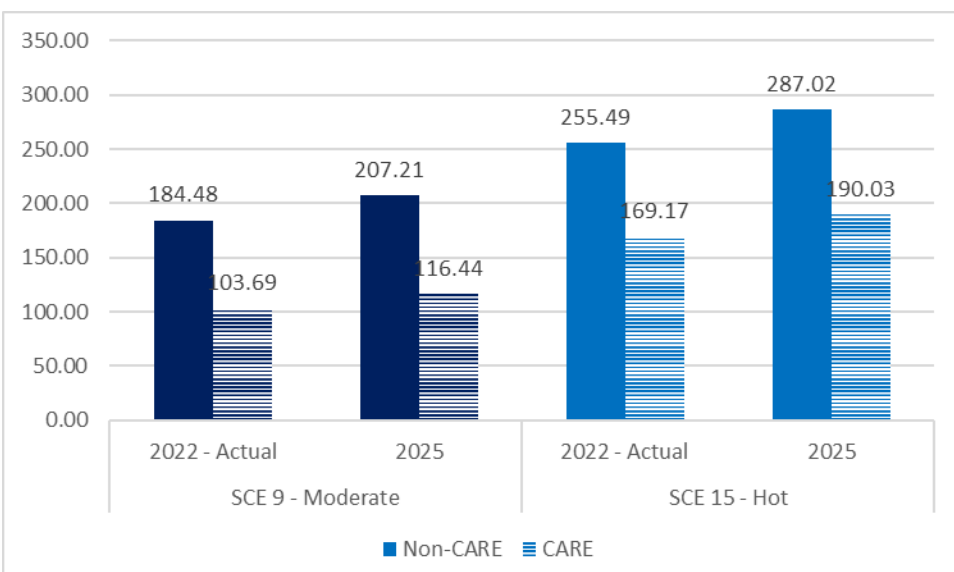
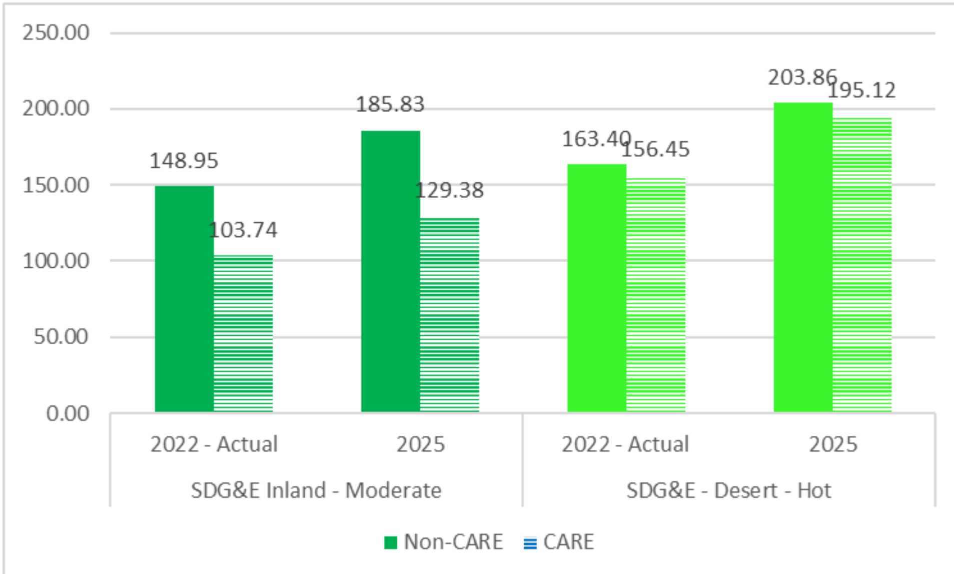


Figure 33: SDG&E Monthly Bill for an Average Customer in a Moderate and a Hot Climate Zone (2022 Actual and 2025 Projected)



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.

Affordability Ratio

The CPUC has developed metrics that take into account socioeconomic conditions of representative low-income households when considering customers' ability to pay for essential services such as electricity. Specifically, in 2020 three metrics were adopted in the first phase of the Affordability Rulemaking[206] to measure the affordability of essential services: the affordability ratio (AR),

206 *See* D.20-07-032 in the docket of A.18-07-006.

socioeconomic vulnerability index (SEVI), and hours at minimum wage (HM). The AR will be examined here, as it most closely aligns with energy burden presented in previous SB 695 reports.

The AR metric quantifies the percentage of a representative household's income that would be used to pay for an essential utility service, after non-discretionary expenses such as housing and other essential utility service charges are deducted from the household's income. The higher an AR, the less affordable the utility service. ARs presented here are for electric service,[207] and are presented for households at the 20th percentile income level (AR20), meaning that the household's income level is only higher than 20 percent of households in the area.[208]

The inclusion of non-discretionary costs in the AR metric, specifically housing costs and other utility services, provides an important piece of additional context when considering utility bills. Housing costs in particular are high in many parts of California, so simply considering bills in relation to household income levels (for example, by looking at a metric such as "energy burden," which expresses energy bills as a percentage of gross household income) does not account for these costs which have a significant impact on a household's ability to pay for electricity.

While the AR20 affordability metric is a more comprehensive affordability metric than energy burden presented in prior SB 695 Reports, the metric does have important limitations. Specifically, the inclusion of socioeconomic variables in the metric calculation means that predicting how affordability will change in future years is a more involved exercise than simply forecasting electricity rates and bills. Estimating future values of the affordability ratio requires estimates of household incomes and housing costs for specific geographic areas and for specific points on the income distribution. The CPUC has not yet established how these forecasts will be produced for forward-looking affordability assessments. This work is part of the scope of the second phase of the Affordability Rulemaking, which is currently underway.

2020 Annual Affordability Report

In July 2020, the CPUC issued D.20-07-032 adopting metrics and methodologies for assessing the relative affordability of public utility service under the Commission's jurisdiction and ordered, among other things, the newly adopted affordability metrics be used in an annual affordability report. The first annual affordability report was issued in April 2021[209] with the 2020 Annual Affordability Report to be released during the second quarter of 2022. Using the most recently available data, the analysis in the 2020 Annual Affordability Report will reflect historical results for electricity, natural gas, water, and communications affordability for the year 2020, as well as

[207] AR may be calculated for a single essential utility service or a combination of services.

[208] ARs are also typically calculated at the 50th percentile of income (AR50) to represent a median income household.

[209] *See* 2019 Annual Affordability Report at: 2019 Annual Affordability Report (ca.gov).

forecasted affordability results for electricity through the year 2025 using the bills that correspond to the cumulative rates forecast in Table 24 as a basis.[210]

[210] Forecasted values for electricity affordability metrics reflect the most current rates forecasts provided by the large electric IOUs via the CPUC's Cost and Rate Tracking (CRT) tool; Energy Division staff may modify the forecasts to reflect estimates for cost recovery applications not yet filed.

IV. Natural Gas Cost and Rate Trends

Background

This SB 695 report on natural gas cost and rate trends was prepared in compliance with Public Utilities (PU) Code section 913.1, which requires the CPUC to provide recommendations on how to limit cost and rate increases, consistent with the state's energy and environmental goals.

The CPUC regulates the natural gas utility services of more than 10 million customers served by Pacific Gas & Electric (PG&E), Southern California Gas Company (SoCalGas), San Diego Gas & Electric (SDG&E), and several smaller utilities.[211] 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[212] 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;[213] and
5. Determine the feasibility of minimizing or eliminating use of SoCalGas's Aliso Canyon gas storage facility while still preserving energy reliability.[214]

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 have chosen 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.

---

[211] 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.

[212] 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.

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

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

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, 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. 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.

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.

Gas rates are impacted by two major processes: 1) changes to revenue requirement, which are mostly determined in GRCs, and 2) changes to forecasted sales demand, which are determined in cost allocation proceedings. The rates paid by individual customers are also impacted by how the revenue requirement is allocated among customer classes in the cost allocation proceedings.[215]

Gas revenue requirement and rates can also be affected by non-GRC proceedings. Examples include proceedings that: modify the use of infrastructure (Aliso Canyon investigation) and reduce greenhouse gas emissions (D.22-02-025 requiring procurement of biomethane).

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. The California Air Resources Board's (CARB) California Greenhouse Gas Cap-and Trade-Program, which is designed to achieve the goals of the Global Warming Act of 2006 (AB 32) to help fight climate change, also increases customer rates.

215 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 2022.[216] 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 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 2020, there were 10,970 miles of intrastate transmission pipeline and 203,442 miles of distribution pipelines in California.[217] Large noncore customers often take gas directly from transmission pipelines.[218] For example, PG&E indicates in A.21-09-018 that about 600 very large volume noncore customers, which account for about 93% 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.

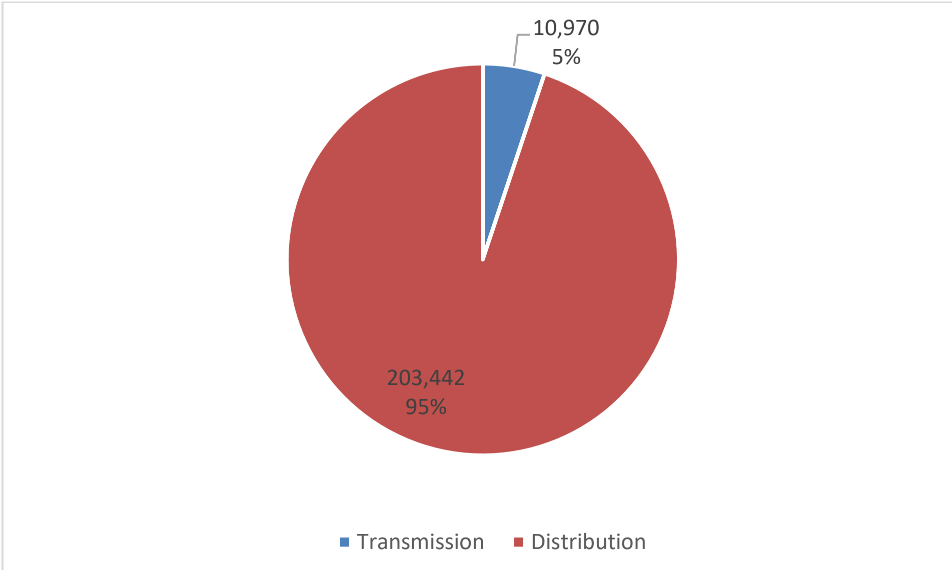
---

216 All data is from 2016 – 2022 IOU February 3, and 7, 2022 responses to Energy Division SB 695 Report data requests. Core procurement revenue requirement is an annual estimate and all other revenue requirements are authorized revenue requirements. For all IOUs, the core procurement revenue requirement estimate is higher in 2022 than in 2021.

217 PHMSA Miles and Facilities 2010+, California: Oracle BI Interactive Dashboards - Public Reports (dot.gov).

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

Figure 34: Miles of Transmission vs. Distribution Pipeline in California (2020)



Source: PHMSA

Storage is part of the gas infrastructure system, but it also has an impact on gas 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, Backbone Transmission, Local Transmission, Distribution, Storage, and PPP and Other. Commodity refers to activities for procuring gas for core customers and includes gas commodity costs and brokerage fees. Backbone Transmission includes 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)[219] and state-mandated PSEP costs. Local Transmission includes capital, O&M, and A&G costs recovered for local transmission pipelines, including TIMP and PSEP costs.[220] Distribution includes customer-related costs and the costs for maintaining and operating high- and medium-

[219] 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.

[220] Local transmission pipelines transport gas from backbone pipelines and storage fields to the distribution system.

pressure distribution pipelines, including the Distribution Integrity Management Program (DIMP).[221] Storage costs include the capital and O&M costs for natural gas storage facilities, including biennial well testing in accordance with CalGEM regulations and other aspects of the utilities' Storage Integrity Management Program (SIMP).[222] Public Purpose Program 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. 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 2022 revenue requirement, 48 percent. Backbone Transmission contributes approximately 10.2 percent to the total gas revenue requirement in 2022. Local Transmission contributes approximately 17.4 percent to the total authorized gas revenue requirement in 2022. In 2018, PG&E completed PSEP work on its Backbone and Local Transmission, at a total cost of $2.42 billion. PG&E continues to modernize its overall transmission portfolio following the company's risk reduction strategy. Storage, which includes core customer gas storage, carrying cost of working gas in storage for core customers, and unbundled storage, contributes about 1.1 percent to the total authorized gas revenue requirement in 2022.[223] Its PPP and Other categories contribute about 8.1 percent to the total authorized gas revenue requirement in 2022.

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.

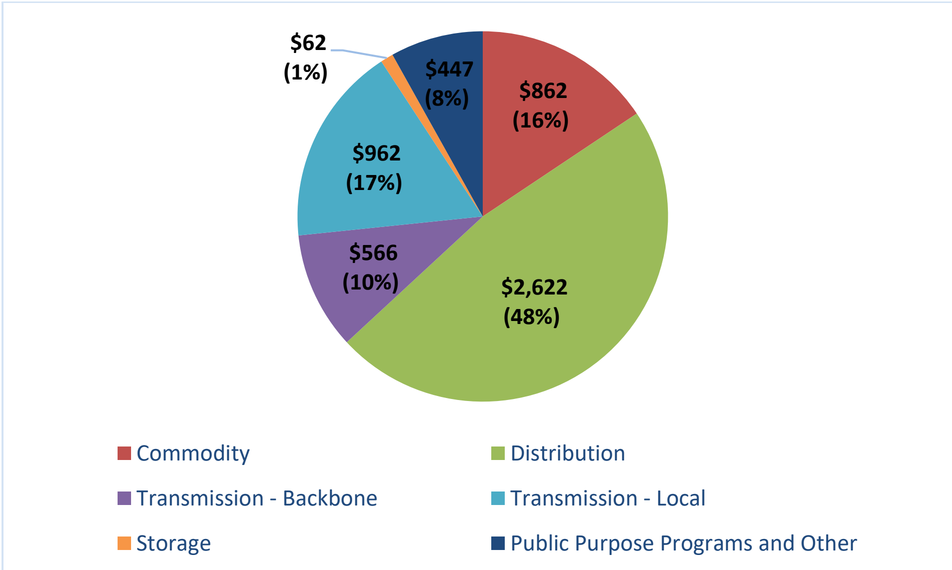
---

221 DIMP is a program developed and implemented by the operator to identify threats to distribution pipeline integrity, rank the relative risk of each threat, take action over and above regulatory minimum requirements if justified by the degree of risk, and track performance measures to determine if the additional actions are effectively reducing those risks. Unlike TIMP, no specific integrity assessment methods are required.

222 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.

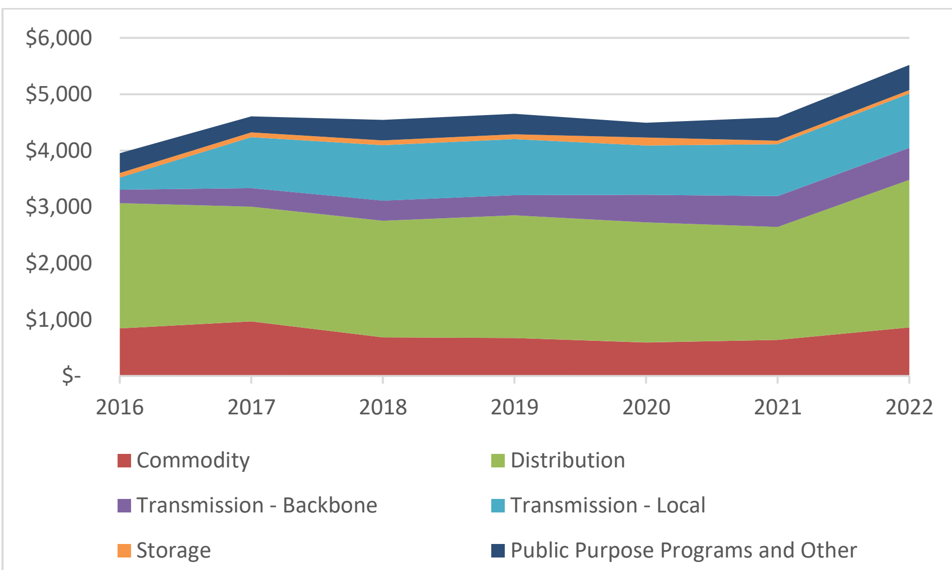
223 The backbone, local transmission and storage revenues for 2019- 2022 were adopted in the 2019 Gas Transmission and Storage D.19-09-025.

Figure 35: PG&E 2022 Revenue Requirement ($ millions)



PG&E's total authorized gas costs, or gas revenue requirement, has increased by approximately 40 percent since 2016. From 2021 to 2022, PG&E's gas revenue requirement increased by 20 percent.

Figure 36: 2016–2022 PG&E January 1 Revenue Requirement by Rate Category ($ millions)[224]



[224] 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 2021 to 2022:[225]

- Commodity: + 35.1 percent,
- Backbone Transmission: + 3.8 percent,
- Local Transmission: + 4 percent,
- Distribution: + 30.6 percent,
- Storage: – 0.6 percent, and
- Public Purpose Programs and Other: + 7.3 percent.[226]

The driver of the 35.1 percent increase in gas commodity costs is a forecasted increase in the weighted average cost of gas in 2022. In PG&E's service area in Northern and Central California, natural gas market prices from November 2021 to January 2022 are 90 percent higher than last winter. See the section on the Nationwide Increase in Commodity Costs below for more information.

Approximately half of the gas distribution increase was driven by the implementation of the 2020 GRC Decision (D.) 20-12-005. The drivers of the increase in that GRC decision are: Meter Protection Program for Abnormal Operating Condition remediation work; Distribution Integrity Management Program's Cross Bore Program[227]; increase in service and main line replacements due to transitioning from a four-year to a three-year compliance leak survey; new Overpressure Protection Enhancements Program; and increased number of regulator replacements.[228] The other significant drivers of the gas distribution increase were for implementation of the wildfire costs approved in D.21-10-022; and recovery of the Residential Uncollectibles Balancing Account. In the 2020 GRC, wildfire liability insurance was part of the general liability insurance forecast and as such subject to the A&G cost allocation methodology, which means that a portion of it was applied to gas rates rather than separately forecasted. In the 2023 GRC, wildfire liability insurance is separate from general liability insurance. In that pending proceeding PG&E has proposed to change the allocation of wildfire liability insurance such that it is charged to bundled electric customers only. The Residential Uncollectible Balancing Account records and tracks uncollected amounts from residential customers, and includes one-time

[225] Data is from IOU responses to Energy Division SB 695 Report data requests, submitted to CPUC on 2/3/2022.
[226] 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. In 2020, the ESA account balance included credits (accrued in 2018-2019); these credits were fully refunded to customers in 2020, resulting in a lower 2020 PPP rate. The primary reason the 2021 PPP rate will increase by 94.6% is due to the fact that customers will no longer receive the ESA account balance credits they received in 2020.
[227] The Cross Bore Program inspects and remedies the inadvertent placement of an underground gas utility line through a wastewater or storm drain system. Cross bores pose a risk as they can result in a gas leak into the sewer system if damaged during mechanical sewer cleaning operations.
[228] Natural gas regulators are used to control pressure on the pipeline system to keep pressure within specific limits. Regulator replacement is the routine replacement of gas distribution residential and commercial regulators when a PG&E evaluation indicates that the regulator is worn and needs to be replaced.

incremental costs associated with the moratorium on disconnections for non-payment ordered by the Commission[229] during the COVID-19 pandemic.

The 2022 revenue requirement increases are due to the following:

- Annual adjustments to regulatory accounts for the over/under recovery of costs resulting in $144.2 million increase.[230] A type of regulatory account called a "balancing account" tracks the difference between actual expenses authorized for recovery by the CPUC and the revenues collected in customer rates to cover those specific expenses. The difference between the authorized expenses and revenues collected in rates accumulates in the balancing account.[231] A "memorandum account" is another type of regulatory account, which tracks costs and revenues. They are subject to audit or review prior to their recovery in rates. Utilities file annual advice letters to adjust their accounts to reflect changes in the accounts' statuses due to under- and/or over-collections. Main drivers for this increase include:
    - 2022 GRC Adjustment:[232] $105.9 million increase[233]
    - San Francisco General Office Sale, $54.2 million decrease related to gain on sale[234]
    - Wildfire Expense Memorandum Account Proceeding, $155.8 million increase[235]
    - Risk Transfer Balancing Account, $103.9 million increase[236]
    - Residential Uncollectibles Balancing Account (RUBA), $31.6 million increase[237]

---

229 D.20-06-003, D.19-07-015, D.19-08-025.

230 Advice Letter 4543-G/4543-G-A. The gas transportation balancing accounts had an increase of $186.3 million effective January 1, 2022. This was updated to $144.2 million to account for the decrease of $42.1 million in the Residential Uncollectibles Balancing Account (RUBA) effective April 1, 2022.

231 A balancing account has an over-collection when its collected revenues exceed authorized expenses; it has an under-collection if the collected revenues are less than authorized expenses.

232 In PG&E's GRC cycle, 2020 was the Test Year where the CPUC sets a revenue requirement for the first year. For years 2021 and 2022, called Post-Test Years, the GRC decision orders how to adjust the Test Year budget for inflation and other factors that may affect costs, such as capital projects.

233 D.20-12-005.

234 D.21-08-027, Advice Letter 4538-G.

235 D.21-10-22, AL 4529-G/6407-E.

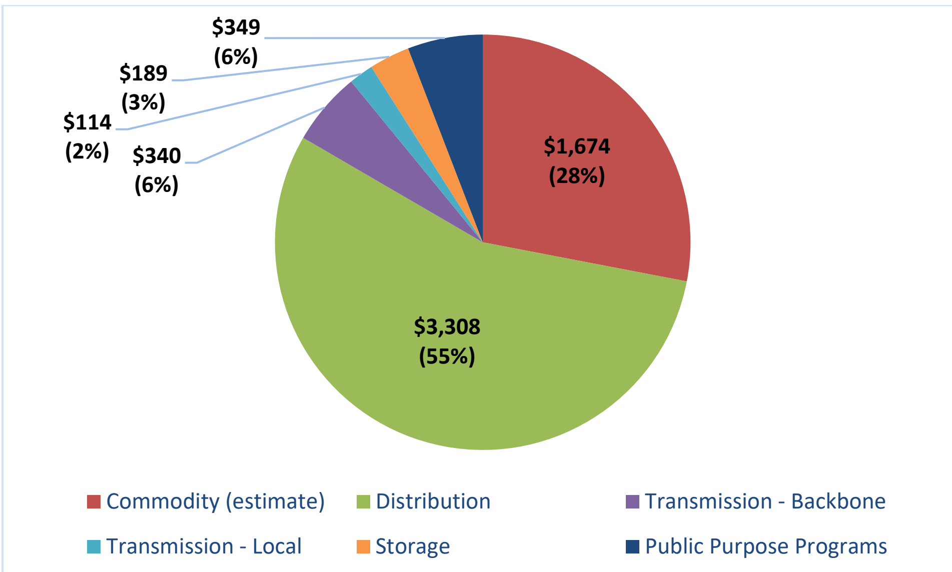
236 D.20-12-005, AL 4543-G. The RBTA is a two-way balancing account that records the difference between amounts authorized in the 2020 GRC and actual costs of insurance premiums. It authorizes PG&E to record and recover the GRC portion of actual insurance costs for the purchase of up to $1.4 billion of general liability insurance coverage. It also authorizes PG&E to record excess liability insurance costs for coverage greater than $1.4 billion.

237 D.20-06-003, AL 4543-G/4543-G-A. RUBA has an impact of $73.7 million effective January 1, 2022 in AL 4543-G. This amount was reduced to $31.6 million effective April 1, 2022 in AL 4543-G-A. On January 27, 2022, PG&E received $340.9 million in funds from the California Arrearage Payment Plan (CAPP) Program to reduce past due energy balances that increased during the COVID-19 pandemic from March 4, 2020 to June 15, 2021 and are at least 60 days past due. Out of this total, PG&E has estimated that the net impact of gas Transportation Subaccount to RUBA is a reduction of $29.2 million.

SoCalGas Revenue Requirement by Rate Category

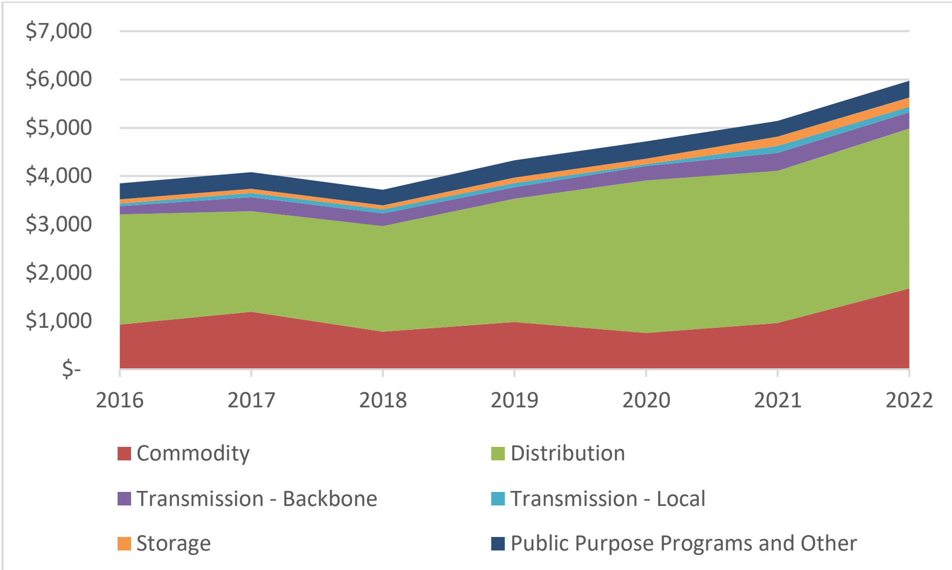
The Distribution component accounts for the largest portion of the 2022 SoCalGas revenue requirement, or 55 percent. This is followed by commodity, which contributes 28 percent to the total gas revenue requirement in 2022. Backbone Transmission, Local Transmission, and Storage contribute approximately 6, 2, and 3 percent to the total gas revenue requirement, respectively. Public Purpose Programs account for 6 percent.

Figure 37: SoCalGas 2022 Gas Revenue Requirement ($ millions)



Since 2016, SoCalGas's revenue requirement has increased by about 55 percent, with a roughly 16 percent increase from 2021 to 2022.

Figure 38: 2016–2022 SoCalGas January 1 Gas Revenue Requirement by Rate Category ($ millions)



Revenue requirement components changed by the following percentages from 2021 to 2022:

- Commodity: + 74 percent,
- Backbone Transmission: – 8 percent,
- Local Transmission: – 24 percent,
- Distribution: + 5 percent,
- Storage: No change
- Public Purpose Programs and Other: + 8 percent.

Commodity and Distribution comprise the largest portion of the 2021-2022 revenue requirement increase. The monthly average 2021 commodity price of 44.8 cents per therm was about 62 percent higher than the average 2020 commodity price of 27.7 cents per therm. Natural gas pricing was impacted by colder weather forecasts in the mid-continent and the northwest for this past winter, high prices in Europe and Asia for LNG exports, and reduced interstate pipeline capacity to California due to the August 16, 2021, rupture of an El Paso pipeline near Coolidge, Arizona. See also the section on the Nationwide Increase in Commodity Costs below for more information.

The 2022 revenue requirement increases are primarily due to the following:

- Annual adjustments to regulatory accounts for the over/under recovery of costs resulting in $98 million increase.[238]

[238] Advice Letter 5884-G.

- This includes a $179.1 million decrease in the under-collected balance of the GRC Memorandum Account 2019[239] and a Greenhouse Gas (GHG) revenue requirement increase of $90.6 million. The core revenue requirement allocation of the GHG increase is $75.2 million. The increase to the GHG compliance cost is reflected in the proxy GHG price, which increased from $18 to $29 per metric tons of carbon dioxide equivalent (MTCO2e).[240]

- Escalation of transportation costs, authorized in the 2019 GRC Decision [241] and approved for the Year 2022 adjustment. This represents an increase of $142 million for year 2022.[242] A large part of the revenue requirement is for costs to upgrade utility infrastructure, operate systems safely, invest in new technology and provide responsive customer service. The utility used an overall cost escalation percentage factor (O&M and capital specific) to calculate the revenue requirement increases for 2022 and 2023. The 2022 revenue increases are done at the company level and do not specify cost increases in specific functional categories (e.g., Distribution, Storage or Transmission). The 2022 revenue increases reflect cost increases in all functional categories combined.[243]
- Reversal of 2018 tax savings amount related to the federal Tax Cuts and Jobs Act.[244] This resulted in an increase of $37.6 million.

In addition, to date SoCalGas has spent over $2 billion on PSEP, which impacts Backbone and Local Transmission costs.[245]

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 SoCalGas' transportation rate,[246] and a percentage of SoCalGas' Storage costs are allocated to SDG&E. The Distribution component accounts for the largest portion of the 2022 SDG&E's revenue requirement, or 62 percent. This is followed by Commodity which contributes 29 percent. Local Transmission, Storage, and Public Purpose Programs contribute approximately 2, 2, and 6 percent, respectively.

---

239 Advice Letter 5338-G; the GRCMA 2019 records the shortfall or overcollection resulting from the difference between revenues and rates in effect as of January 1, 2019, and the final adopted revenues and rates in D.19-09-051.

240 Advice Letter 5884-G-A. Residential gas household customers receive annual California Climate Credits in April, which offset the GHG compliance costs.

241 *See* D.19-09-051.

242 Advice Letter 5915-G.

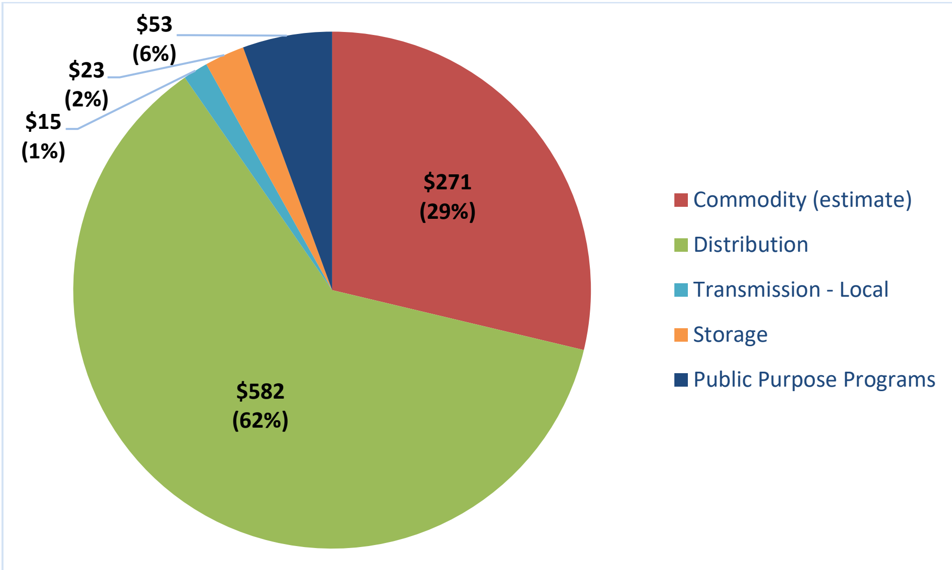
243 D.21-05-003.

244 Advice Letter 5541. This advice letter implemented adjustments to revenue requirements to reflect 2018 tax savings from the Tax Cuts and Jobs Act.

245 January 2021 SoCalGas PSEP Update, Appendix D: https://www.socalgas.com/sites/default/files/SCG-SDGE%20Monthly%20PSEP%20Status%20Report%20202101.pdf.

246 For ratemaking purposes, SDG&E's backbone transmission are recovered in SoCalGas' transportation rates due to the transmission system integration between the two utilities.

Figure 39: SDG&E 2022 Gas Revenue Requirement ($ millions)

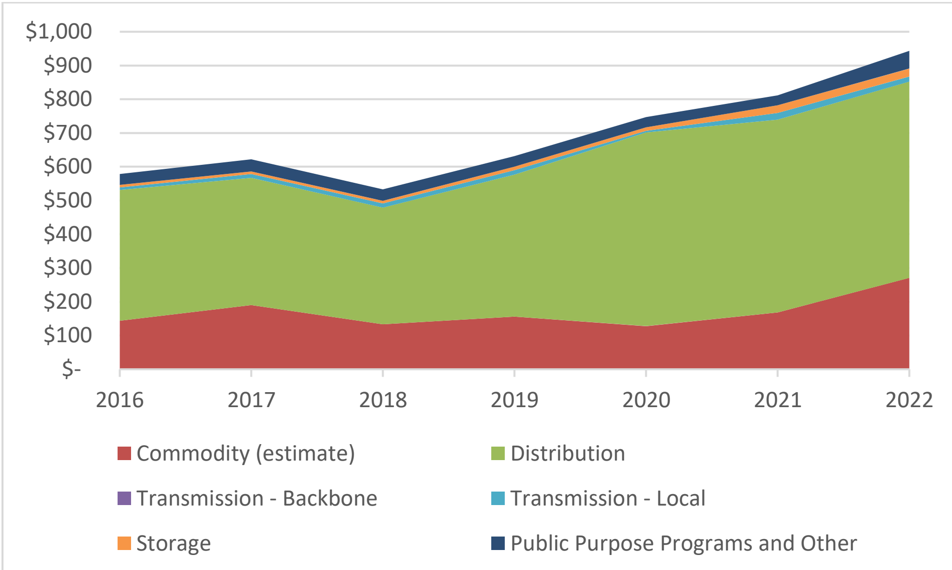


SDG&E's gas revenue requirement has increased by approximately 63 percent since 2016, with a roughly 16 percent increase from 2021 to 2022.

Revenue requirement components changed by the following percentages from 2021 to 2022:

- Commodity: + 61 percent,
- Local Transmission: – 24 percent,
- Distribution: + 2 percent,
- Storage: + 2 percent, and
- Public Purpose Programs and Other: + 81 percent.

Figure 40: 2016–2022 SDG&E January 1 Gas Revenue Requirement by Rate Category ($ millions)



Commodity increased by 61 percent due to supply and demand as stated above. See also the section on the Nationwide Increase in Commodity Costs below for more information. Distribution revenue requirement increased mainly due to GHG compliance costs and revenue requirement for the remaining years in the 2019 GRC cycle.[247] The Local Transmission revenue requirement decreased due to a decrease in PSEP spending for local transmission. Public Purpose Programs increased due to authorization to seek recovery for the AB 841 (Ting, 2020) School Energy Efficiency Stimulus Program (SEESP), or $13.8 million.[248]

The 2022 revenue requirement increases are due to the following:

- Annual Adjustments to regulatory accounts for the over/under recovery of costs resulted in increase of $17.4 million[249]
    - This includes a $25.0 million increase to the GHG revenue requirements[250] and $35 million decrease from the GRC Memorandum Account 2019 balance. [251]

247 Advice Letter-4519-G-A.

248 Advice Letter-4519-G-A.

249 Advice Letter 3024-G: A decrease in the under-collected balance of the GRC Memorandum Account 2019, increase in the Core Fixed Cost Account (CFCA), and decrease in the Noncore Fixed Cost Account (NFCA).

250 Advice Letter 5884-G-A. Residential gas household customers receive annual California Climate Credits in April, which offset the GHG compliance costs.

251 Advice Letter 3024-G; the GRCMA 2019 records the shortfall or overcollection resulting from the difference between revenues and rates in effect as of January 1, 2019, and the final adopted revenues and rates in D.19-09-051.

- Escalation of transportation costs, authorized in the 2019 GRC Decision, and approved for 2022,[252] in D.21-05-003.[253] This represents a $13 million increase. The costs are to upgrade utility infrastructure, operate systems safely, invest in new technology and provide responsive customer service.
- Reversal of 2018 tax savings amount related to the federal Tax Cuts and Jobs Act[254] resulting in $5.97 million decrease.

Nationwide 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 (usually the largest component of the procurement rate) can be very volatile and are difficult to forecast a year in advance. Changing the procurement rate monthly provides customers a more accurate representation of the utility procurement costs in a particular month. Using that information, customers may want to reduce their usage when procurement rates are relatively 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 that fluctuate based on national gas market prices. The rates are based on a 30-day forecast of natural gas market prices, and 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.

Gas prices were high both nationally and internationally during fall 2021 and winter 2021-22. The U.S. Energy Information Administration (EIA) reports that, "The average Henry Hub spot price, the national benchmark spot price of natural gas, was 47% above the five-year average in 2021, at $3.89 per million British thermal units (MMBtu), compared with the five-year average price of

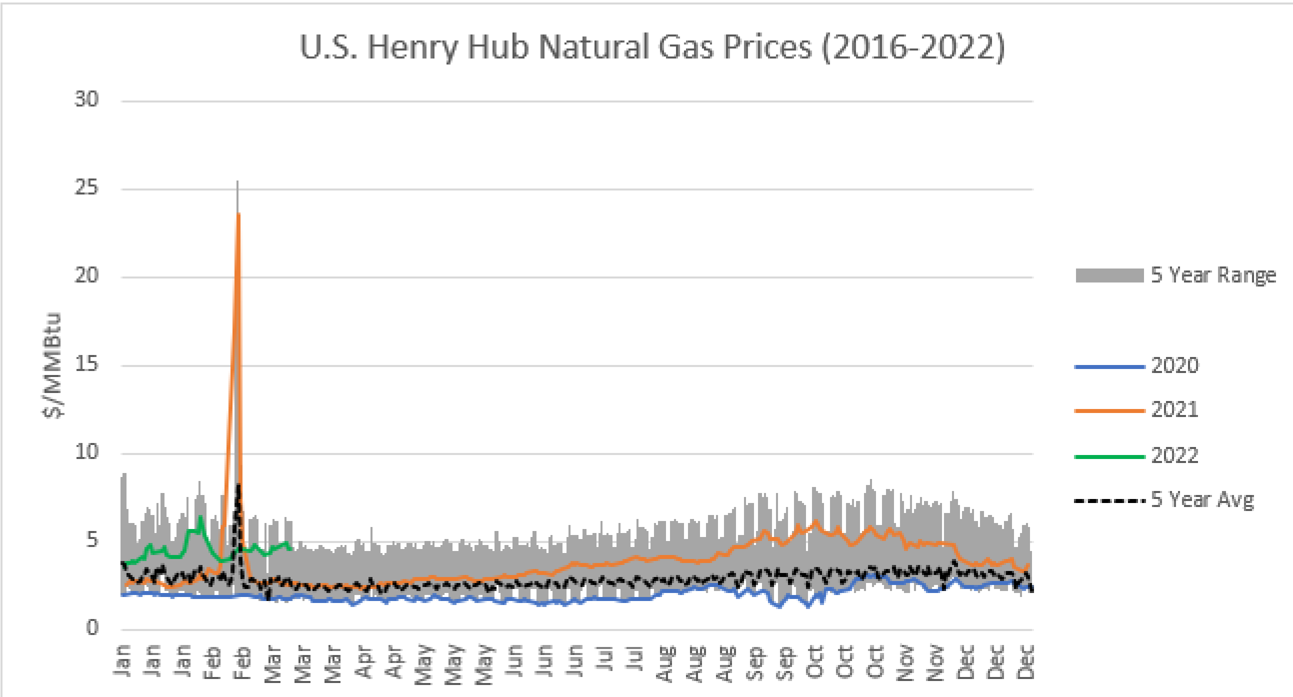
[252] The revenue requirement authorized in the 2019 GRC decision (D.19-09-051) is the amount of revenue the utility needs to earn in a test year (2019), i.e., the first year in the GRC cycle, and post-test years (2020 and 2021), i.e., remaining years in the GRC cycle, in order to provide service to its customers. The revenue requirement for years 2022 and 2023 were approved in D.21-05-003.

[253] Advice Letter 2997-G.

[254] Advice Letter 2816-G.

$2.65/MMBtu…"[255] Several factors contributed to rising prices, including hurricanes, low storage levels, high liquified natural gas (LNG) exports, and volatile international markets.

Figure 41: Average Henry Hub Spot Prices, 2016-2022



Source: EIA.

Nationally, there were price concerns in the fall, as Hurricanes Ida and Nicholas disrupted gas production in the Gulf of Mexico.[256,257] Gas storage, which was depleted by the February 2021 Winter Storm Uri event, was slow to refill, remaining 6.3 percent below the five-year average at the end of September.[258] A warm fall and increasing gas production allowed national storage levels to rise slightly above the five-year average by the end of December.[259] However, a cold start to 2022 in much of the U.S. led to storage draws of over 200 billion cubic feet (Bcf) per week for four weeks[260] and to rising prices. The February 2022 average spot price at Henry Hub was $4.69/MMBtu.[261] Just as the weather

---

[255] EIA Natural Gas Weekly Update for the week ending March 2, 2022: Natural Gas Weekly Update (eia.gov).

[256] S&P Global Platt's Gas Daily, "NYMEX Henry Hub gas nears $6 on supply concerns, lingering Ida impact," September 29, 2021.

[257] EIA Natural Gas Weekly Report for the week ending October, 27, 2021, "Hurricane Ida reduced U.S. natural gas production more than any other hurricane over the past ten years": Natural Gas Weekly Update (eia.gov).

[258] EIA Natural Gas Weekly Report for the week ending September 29, 2021: Natural Gas Weekly Update (eia.gov).

[259] Reuters, "U.S. Natgas falls to six-month low on rising output, drop in European prices," December 30, 2021: U.S. natgas falls to six-month low on rising output, drop in European prices | Reuters.

[260] Storage withdrawals were over 200 Bcf/week from the week ending January 19 to the week ending February 9, 2022: Natural Gas Weekly Update (eia.gov).

[261] EIA Short Term Energy Outlook, March 8, 2022: Short-Term Energy Outlook - U.S. Energy Information Administration (EIA).

started to ease, Russia's invasion of Ukraine created fresh uncertainty in the market, leading to price increases. With national storage levels 16 percent below the five-year average on March 4, 2022, national markets may see price pressure continue into the spring injection season.[262]

Internationally, low storage inventories in Europe at the end of summer 2021, a coal shortage in China, and the Russian invasion of Ukraine caused LNG prices to hit historic highs. Average weekly LNG prices in Europe were $41.06/MMBtu for the week ending March 3, 2022, compared to $5.70/MMBtu in the same week in 2021. High LNG prices caused U.S. LNG exports to increase from an average of 9.6 Bcf per day (Bcfd) in the first half of 2021[263] to 11.2 Bcfd in January 2022. The EIA expects U.S. LNG exports to average 11.3 Bcfd in 2022, a 16 percent increase from 2021.[264]

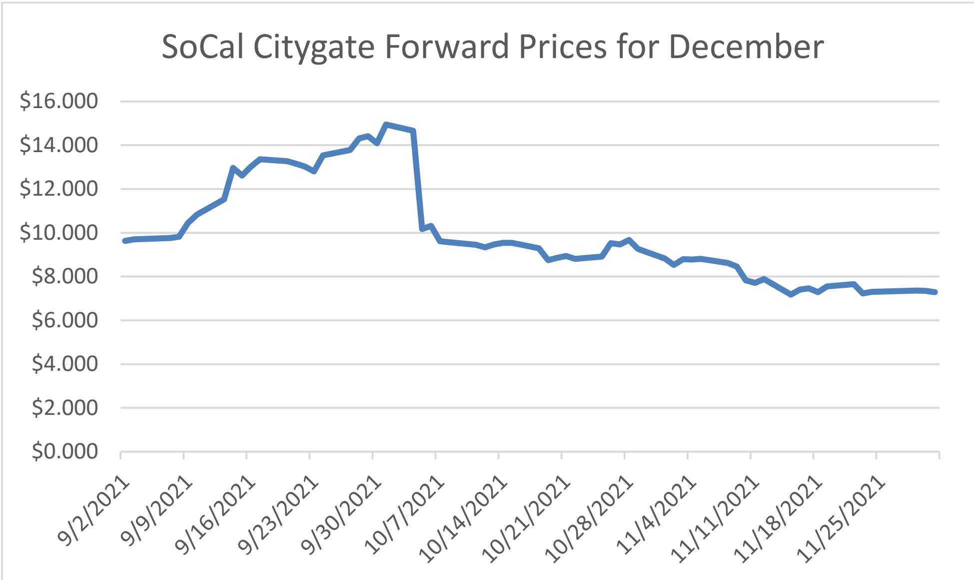
In addition to the national and international factors above, an August 15 pipeline rupture in Coolidge, Arizona, reduced the amount of gas flowing west on an important interstate pipeline system serving Southern California. In response, December futures prices at the SoCal Citygate rose precipitously, reaching a high of $14.95/MMBtu on Friday, October 1, 2021. However, on that same day, SoCalGas announced that it had completed in-state pipeline repairs that increased pipeline capacity by 260 million cubic feet per day (MMcfd) and the CPUC issued a Proposed Decision increasing the Aliso Canyon storage limit. By Tuesday, October 5, 2021, December forward prices had dropped to $10.12/MMbtu. By the end of November, December futures prices had fallen to the low $7 range. The combination of increased pipeline and storage capacity helped calm markets and mitigate what could have been even higher prices in Southern California.

262 EIA Natural Gas Weekly Report for the week ending March 4, 2022: Weekly Natural Gas Storage Report - EIA.

263 EIA, "U.S. liquefied natural gas exports grew to record highs in the first half of 2021," July 27, 2021. See: https://www.eia.gov/todayinenergy/detail.php?id=48876.

264 EIA Short Term Energy Outlook, March 8, 2022: Short-Term Energy Outlook - U.S. Energy Information Administration (EIA).

Figure 42: December Forward Gas Prices at the SoCal Citygate, 9/2/2021-12/1/2021 (MMBtu)



Source: Natural Gas Intelligence Forward Look

In contrast to national weather trends, California experienced very cold weather in December and relatively average temperatures in January. In the gas industry, heating degree days (HDDs) are used to compare temperature trends in different years. One HDD is recorded when the average temperature for the day is one degree below 65° Fahrenheit. The lower the temperature, the more HDDs there will be for a given day. For example, a 40°-degree day counts as 25 HDDs.[265] In December, there were 45 HDDs more than the 10-year average in the PG&E service territory and 76 more in the area served by SoCalGas (see Table 26 below). The cold weather in December caused customers to use more gas than usual, so their bills reflected both higher commodity costs and more therms of gas consumed.

Table 26: Heating Degree Days in Dec. 2021 and Jan. 2022 Compared to the 10-Year Average

	Dec. 2021	Dec. 10-Year Avg.	+/- Dec. Avg.	Jan. 2022	Jan. 10-Year Avg.	+/- Jan Avg.
PG&E	370	325	+45	311	301	+10
SoCalGas	336	260	+76	237	238	-1

Source: Utility data request responses.

265 EIA, Units and calculators explained: Degree-days - U.S. Energy Information Administration (EIA).

The impact of high natural gas prices on California utilities can be seen in Figures 43 and 44 below. Figure 43 compares July to December 2021 monthly natural gas prices at PG&E Citygate, SoCalGas Citygate, and SoCalGas Border to the same months in 2020.

Figure 43: Natural Gas Prices per MMBtu

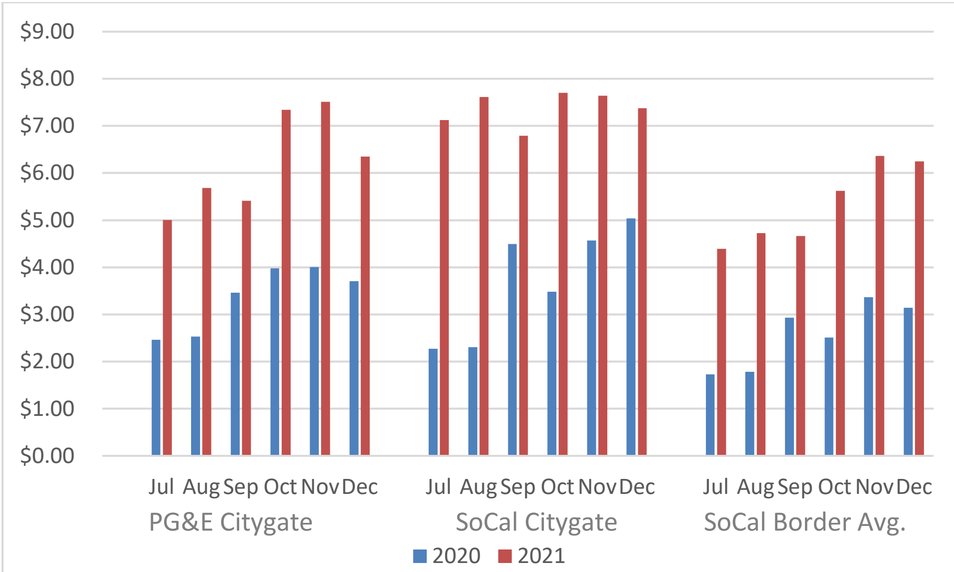
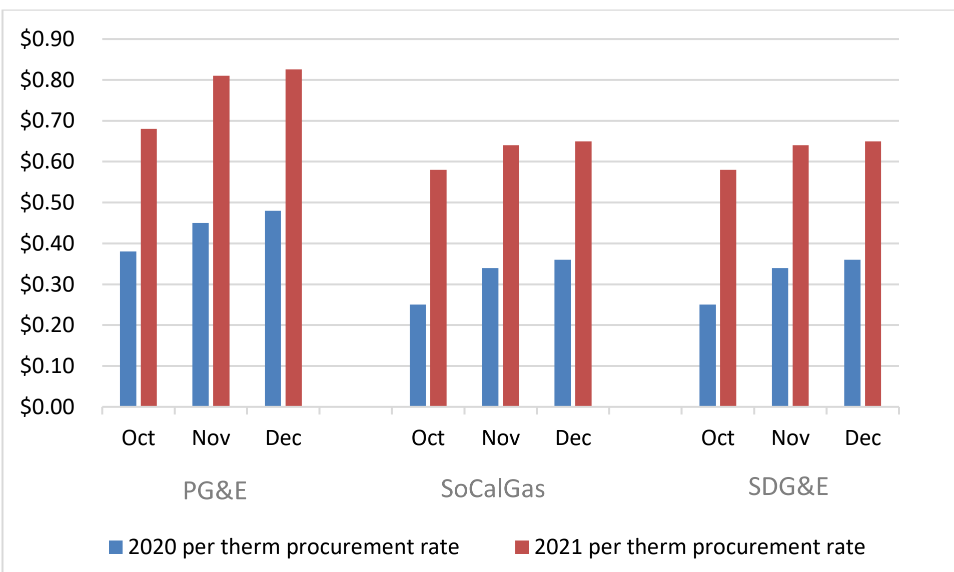


Figure 44 compares the monthly Procurement Rates paid by core customers for PG&E, SoCalGas, and SDG&E in 2020 and 2021.

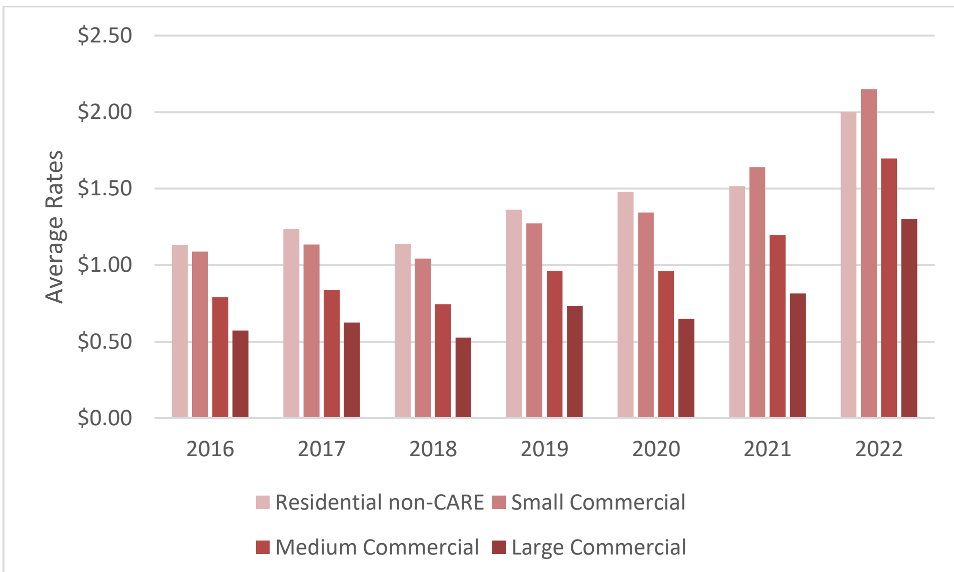
Figure 44: PG&E, SoCalGas, SDG&E Gas Procurement Rates 2021 vs 2020



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 45–47. Each class shows an upward trend during this period (2016 to 2022). 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.[266] 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,[267] procurement, transportation, and the PPP surcharge. CARE residential customers get a 20 percent discount off the entire bill.

Figure 45: SoCalGas Gas Average Rates per Therm by Class in Effect January 1 (2016-2022)



[266] 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).

[267] SoCalGas imposes a $5 fixed charge, while SDG&E and PG&E impose a $4 minimum charge.

Figure 46: SDG&E Gas Average Rates per Therm by Class in Effect January 1 (2016-2022)

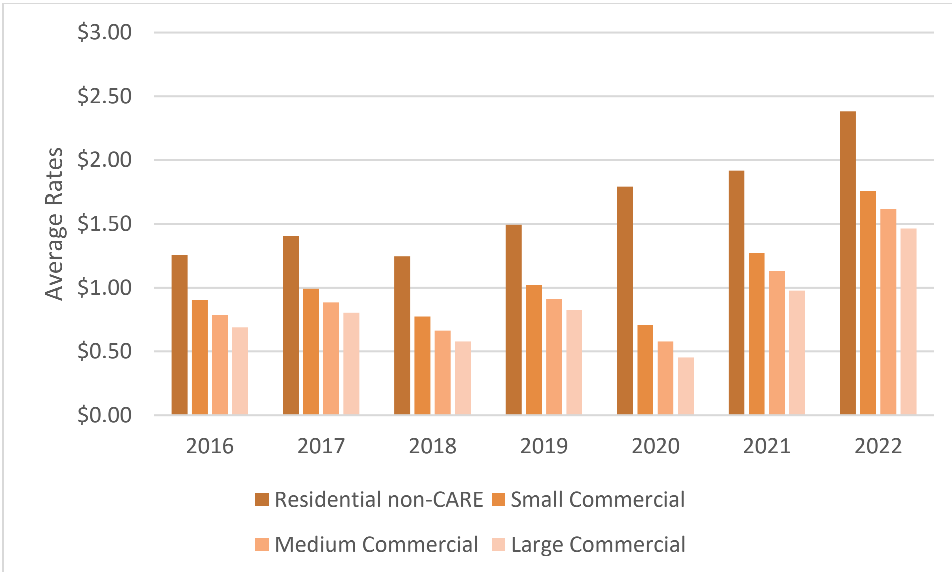
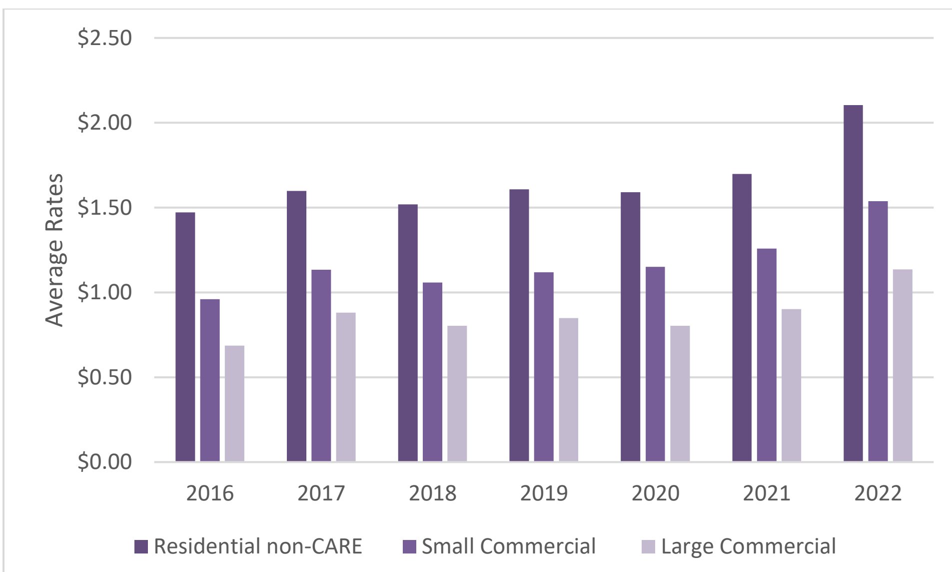


Figure 47: PG&E Gas Average Rates per Therm by Class in Effect January 1 (2016-2022)



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.[268] These amounts represent increases of 15%, 28%, 38% and 39% in 2023, 2024, 2025 and 2026, respectively, from PG&E's 2022 adopted gas revenues. PG&E's proposed gas revenues comprise 31% of its utility-wide total GRC proposed revenues beginning in 2023, rising to 35% by 2026.

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.21-06-21).

PG&E requests 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).

Gas Procurement Costs Incentives

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

On April 1, 2021, PG&E submitted its CPIM performance report, which covered the period November 1, 2018, though October 31, 2019 (Year 26). The reported stated that PG&E's core gas costs and reservation charges were $53,238,074 below the CPIM benchmark and that, according to the mechanism, the savings should be split with $45,142,547 going to ratepayers and $8,095,519 to shareholders. On January 25, 2022, the CPUC's Public Advocates Office issued its Monitoring and

[268] PG&E Testimony in A.21-06-021 dated 2/28/2022, Exhibit PG&E-11, Ch. 2, p. 2-2, Table 2-1.

Evaluation Report for the Year 26 CPIM, which confirmed the total savings, shareholder award, and ratepayer benefits as presented in the report. On January 28, 2022, PG&E submitted Advice Letter 4562-G requesting approval of the $8 million shareholder reward. The Advice Letter was approved on February 27, 2022. PG&E's recorded gas costs were $53 million below the benchmark, which resulted in core ratepayer gas commodity costs that were $45 million below the prevailing market price.

Energy Division staff are working on a report reassessing the CPIM program that is expected to be completed by July 2022.

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 seeks 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.

Application to Amend Ruby Pipeline Contract

On August 28, 2020, PG&E filed an Application to seek approval of amendments to two contracts executed between Ruby Pipeline, LLC and PG&E. The Application seeks approval of various contract amendments which were negotiated between the parties to resolve a contract dispute resulting from PG&E's bankruptcy and downgrading of its credit rating. The proposed contract amendments were approved in D.21-12-035. They avoided the costs of litigation and PG&E's obligation to provide substantial incremental collateral, which would otherwise have been imposed on PG&E as a result of its bankruptcy and concomitant credit downgrading, per the original contract. There were no rate impacts, although PG&E's ability to decrease its capacity purchases on the Ruby Pipeline in the future were enhanced, which could reduce pipeline capacity costs in the coming years.

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.[269] The CPUC issued D.21-05-003 in May 2021, authorizing SoCalGas' revenue requirement adjustments of $142.1 million for 2022 (4.53% increase) and $130.2 million for 2023 (3.97% increase) and SDG&E's revenue requirement adjustments of $87.3 million for 2022 (3.92% increase) and $85.6 million for 2023 (3.70% 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. This revenue requirement reductions resulted in lower rate impacts for customers.

Gas Cost Incentives

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

On June 15, 2021, SoCalGas submitted an application stating that its core procurement costs for the period April 1, 2020, through March 31, 2021, (Year 27), were $184,744,972 below the benchmark and seeking approval of a shareholder reward of $11,143,275 for its performance. On October 15, 2021, the CPUC's Public Advocates Office issued its Monitoring and Evaluation Report for Year 27 of the GCIM, which confirmed the total savings, shareholder award, and ratepayer benefits as presented in the application. D.22-03-007 was issued on March 17, 2022, approving SoCalGas' request. SoCalGas' recorded gas costs were $185 million below the benchmark, which resulted in core ratepayer gas commodity costs that were $174 million below the prevailing market price.

Energy Division staff are working on a report reassessing the GCIM program that is expected to be completed by July 2022.

---

[269] *See* D.20-01-002.

Triennial Cost Allocation Proceeding (TCAP)

In February 2021, SoCalGas and SDG&E filed a petition for modification of the Triennial Cost Allocation Proceeding (TCAP) decision[270] seeking to delay the next TCAP filing because the current schedule would not allow the utilities to use certain data from their upcoming 2022 GRC. In July 2021, the CPUC adopted D. 21-07-019 extending the next TCAP filing to August 15, 2022, with effective rates on January 1, 2024. This decision also directed the utilities to submit updated cost allocations based on current data for the interim, with rates effective January 1, 2023. The cost allocations were based on current data (embedded costs for storage and transmission based on 2020 recorded data and the long-run marginal costs escalated to 2023 dollars for customer-related, medium- and high-pressure distribution functions). These updates resulted in $173 million[271] less revenue requirement allocated to SoCalGas core customers and $7.1 million[272] less revenue requirement allocated to SDG&E core customers. As a result, effective January 1, 2023, residential customers will have 6.2 percent decrease and $1.9 percent decrease in their gas transportation rates for SoCalGas and SDG&E, respectively.

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. 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

[270] D.20-02-045.

[271] Advice Letter 5907-G.

[272] Advice Letter 3042-G.

closure and what the timeline and other parameters will be. The CPUC anticipates a ruling in this proceeding before 2023.

The CPUC is also using this proceeding to determine the Aliso Canyon facility's maximum allowable gas storage inventory. The allowed inventory level impacts customers rates because higher storage inventory allows for lower gas costs to ratepayers by enabling the utility to buy and store gas when prices are low and use its stored gas when prices are high. The CPUC increased the maximum inventory level for the facility in November 2021. That level will remain in place until the Commission issues a new decision in the proceeding.

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 Commission 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 Commission denied SDG&E's and SoCalGas' request for a CPCN for the proposed Line 3602 project.[273]

The Commission opened a second phase to review cost forecasts pertaining to the SoCalGas/SDG&E's Line 1600 PSEP.[274] 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 Commission 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 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 Commission's Safety and Enforcement Division formally approved on January 15, 2019. This cost forecasts review proceeding is ongoing. The reasonableness of forecasts established in this phase will be reviewed in later applicable GRCs.

---

[273] *See* D.18-08-028.

[274] *See* D.20-02-024.

Angeles Link Application

On February 17, 2022, SoCalGas filed A.22-02-007 requesting authorization to establish the Angeles Link Memorandum Account, which would track the incremental costs associated with stakeholder engagement, engineering, design, and environmental work for a proposed pipeline delivering "renewable green hydrogen" into the Los Angeles Basin. The application does not specify a cost recovery mechanism for expenses recorded in the memorandum account, but the company could request cost recovery from ratepayers in a future proceeding if the memorandum account is approved. It states that the project must 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 references 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 says 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 does not name specific end users of the renewable hydrogen, but it describes an intent to serve future green hydrogen end users, including "hard-to-electrify" industries, electric generators, and the heavy-duty transportation sector. The application says 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 does not specify how the hydrogen would be produced other than that it would come from electrolysis powered by renewable electricity.

The application describes 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[275] 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 response to California's climate goals. As noted above,

---

275 *See* R.20-01-007.

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 requires strategic planning to reduce the revenue requirement.

The rulemaking has two tracks. Track 1 is intended to establish baseline standards and address issues of more immediate concern. These include: determining whether changes to the reliability standards are needed and, if so, how any additional costs will be recovered and allocated; considering a change to the Operational Flow Order (OFO) penalty structure, which provides a financial incentive for gas customers, including electric generators, to deliver sufficient gas supply; and evaluating whether gas-electric interdependency requires the establishment of new reliability and cost containment protocols. A Proposed Decision on the OFO penalty structure was issued on March 18, 2022. A Proposed Decision on the remaining Track 1 issues is expected in Quarter 2 of 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. In this proceeding, the CPUC 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 and reducing distribution pipeline miles to decrease revenue requirement over time.

The CPUC held two workshops in January and issued a workshop report in March.[276] A Proposed Decision expected in November 2022.

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 will focus on data and process, considering a long-term strategy for managing gas planning going forward. It is expected to begin in 2023.

Affordability Proceeding 2022 "En Banc" Proposals

The CPUC held an Affordability Proceeding 2022 En Banc[277] on February 28 and March 1 of 2022 as part of Phase 3 of Affordability Rulemaking A.18-07-006, which examined proposals to contain costs and mitigate rate increases. Stakeholder proposals focusing on gas ratepayers included the following:

---

[276] R.20-01-007 Track 2a Gas Infrastructure Workshop Report: published-track-2-january-workshop-report--march-1-2022-454981991pd.pdf (ca.gov).

[277] *See* https://www.adminmonitor.com/ca/cpuc/en_banc/20220228/ (2-28-22); and https://www.adminmonitor.com/ca/cpuc/en_banc/20220301/ (3-1-22).

- Authorize utilities to deploy capital and recover cost for building decarbonization upgrades via tariffed on-bill structures that enable participation regardless of income, credit score, or renter status.
- Implement rate or infrastructure planning mechanisms to avoid excessive gas infrastructure costs falling disproportionately on residential customers who cannot electrify.
- Determine if electrification warrants securitization and/or accelerated depreciation of natural gas assets.
- Implement a Renewable Balancing Services tariff that would charge different rates to different customer classes, especially during peak hours, based on amount of natural gas use.
- Evaluate natural gas rates and affordability in coordination with the Long-Term Gas Planning Rulemaking.
- Determine how to efficiently prune the natural gas system while providing safety.
- Legislative action to ensure long-term budget availability and use state revenue to recover costs for programs, such as CARE.

The next step in Phase 3 of the proceeding would build on en banc discussions and solicit recommendations and strategies from parties to mitigate rate increases. A workshop would then discuss the recommendations, and a proposed decision scheduled for early 2023 would address top affordability proposals.

Rulemaking to Implement Dairy Biomethane Pilots

Pursuant to SB 1383 (Lara, 2016), the CPUC opened a rulemaking[278] 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 have been signed and are under review at the CPUC. Construction of these projects should take approximately two years for interconnection to occur. Upon completion, the new dairy biomethane facilities will convert biogas from dairy digesters into renewable natural gas (RNG) for heating and transportation purposes and 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 will now come online in 2022. As of January 31, 2022, only one of the six projects – Weststyn – was not yet online.

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

Biomethane Procurement Considerations (SB 1440 Implementation)

In response to SB 1440 (Hueso, 2018), the Commission adopted a biomethane procurement standard in D.22-02-025. The decision establishes a biomethane procurement program that is 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. Renewable gas 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 required approval of 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.

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 2021, CPUC staff reviewed the Risk Spending Accountability Reports (RSARs) filed by the IOUs 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. As of 2021, the process has yielded valuable input on the content and format of the filings.

- Protect Our Communities Foundation's comments to the[279] Sempra Companies' 2020 joint RSAR called for clarifications on how IOUs derive authorized spending.

---

[279] See the comments, p. 3:https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/risk-spending-accountability-reports/sdge-and-socal-2019-comments-poc-comments.pdf; See also the recently mailed S-MAP (R.20-07-013) ruling on Appendix A, p. 7: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M467/K577/467577874.PDF.

- TURN's comments[280] to the same filing showcased underspending.

PG&E submitted its RSAR on March 31, 2022.

SDG&E and SoCalGas plan to submit their RSAR by July 1, 2022. CPUC Staff will review the reports and issue its observations and recommendations accordingly.

Gas Line Extension Subsidies Considered in Phase III of Building Decarbonization Proceeding

In R.19-01-011, the CPUC is considering programs and policies to support the decarbonization of buildings in California. In Phase III of the proceeding, the CPUC is considering changing the rules regarding allowances, refunds, and discounts paid to builders to help facilitate the connection of buildings to the gas distribution system. In November 2021, CPUC's Energy Division staff released a report recommending the complete elimination of these payments 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.[281] According to the staff report, "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."[282] The CPUC is expected to issue a Proposed Decision in the third quarter of 2022.

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

---

280 See the comments, p. 7: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/risk-spending-accountability-reports/sdge-and-socal-2019-comments-turn-comments.pdf .

281 R.19-01-011, ruling of November 16, 2021, pp. 21, 23.

282 Ibid, p. 31.

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.

To minimize the costs associated with the CalGEM rules, PG&E proposed in its 2017 Gas Transmission and Storage (GT&S) application filing (A.17-11-009) to retire its Los Medanos and Pleasant Creek gas storage facilities. In 2019, the CPUC approved PG&E's proposal to retire both storage facilities.[283] To compensate for the reduction in PG&E storage inventory due to the field closures and compliance with the new CalGEM regulations, the decision required Core Gas Supply and the Core Transport Agents to purchase sufficient gas storage capacity from the Independent Storage Providers (ISPs) to meet a 1-in-10-year cold event.[284] All of the ISPs in California are required to comply with the 2018 CalGEM regulations. Thus, the CalGEM costs incurred by the ISPs may indirectly impact the contract prices charged to PG&E, which would be passed on to ratepayers. However, the expectation is that ISPs will be able to comply with the CalGEM regulations at lower cost than PG&E because their storage fields are newer.

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 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.

If SoCalGas' Risk Management Plan is approved, its capital cost projections are estimated to be approximately $38 million for 2022 and 2023. Its O&M costs are projected to be $14 million for 2022 and 2023. If SoCalGas' Risk Management Plan is not approved and SoCalGas is required to comply with the default regulatory rules, it would accrue approximately $112 million in combined capital costs for 2022 and 2023, and its O&M costs would increase to $27 million for those years. 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.

---

[283] In its 2021 GRC filing, PG&E has proposed to retain the Los Medanos gas storage facility to meet its forecasted Peak Day Supply Standard.
[284] See D.19-09-025, p. 41.

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.[285] The 2012 rupture of a pipeline near a highway in Sissonville, West Virginia demonstrated the limitations of the definition of High Consequence Areas (HCAs),[286] 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.[287]

"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 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

---

[285] 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.

[286] 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.

[287] 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.

that don't have verifiable records that they have met the modern standard.[288] 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:

---

288 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 27: 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[289]	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 28: Miles of Pipeline Subject to PHMSA Mega Rule

	PG&E	SoCalGas
MAOP Reconfirmation	345	1,040
Materials Verification	210[290]	1,354
Assessment Outside HCA	873.5	253

Source: SED.

Track 2b of the Long-Term Gas Planning OIR, which is scheduled to begin in October 2022, 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.

---

[289] 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.

[290] 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 California Air Resources Board (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.

V. 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 2022 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 .

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:

- **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-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.

- **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.

Appendix C – PG&E 2023 GRC Affordability Metrics Testimony

PG&E 2023 GRC Affordability Metrics Testimony

On February 23, 2022, PG&E provided an affordability metrics report in accordance with the October 1, 2021 Assigned Commissioner's Scoping Memo and Ruling in PG&E's 2023 GRC[291] which directed PG&E to work with Energy Division to prepare an analysis of PG&E's 2023 GRC revenue requirement requests incorporating affordability metrics under development in the Affordability Rulemaking.[292] PG&E employed the affordability metrics in the CPUC's Energy Division, Water Division, and Communications Division staff proposal dated November 5, 2021, in the Affordability Rulemaking (Staff Proposal).[293]

Electric AR20 data[294] from PG&E's affordability metrics report is reproduced here to give a sense of how this data may be presented in a CPUC proceeding.[295] AR20 is generally used to represent low-income customers that may be eligible for the California Alternate Rates for Energy (CARE) program, as it represents households at the lowest 20 percent of income distribution for a given area.[296] Table 29 presents actual (for 2021) and projected (for 2023 – 2026) electric AR20s for Non-CARE customers assuming PG&E's 2023 GRC request is adopted in full, highlighting the AR20s of customers in Climate Zone R.[297]

---

291 *See* A.21-06-021.

292 This is the first affordability metrics report utilizing the Affordability Ratio in a proceeding. For these calculations PG&E used the 2019 AR Calculator published following the November 15, 2021, Public Workshop on Affordability Metrics Implementation. *See* "PG&E Regulatory Case Documents, Supplemental Testimony" filed on February 23, 2022, in case "GRC 2023 Phase I" at: Regulation (pgera.azurewebsites.net).

293 *See* Affordability Metrics Implementation Staff Proposal.

294 As discussed in this report starting on page 85, "Affordability Ratio," the AR metric quantifies the percentage of a representative household's income that would be used to pay for an essential utility service, after non-discretionary expenses such as housing and other essential utility service charges are deducted from the household's income. The higher an AR, the less affordable the utility service. ARs presented here are for electric service, and are presented for households at the 20th percentile income level (AR20), meaning that the household's income level is only higher than 20 percent of households in the area.

295 As previously stated, presentation of the metrics is under development in the Affordability Rulemaking and subject to change pending a Phase 2 Decision in the proceeding. In addition, PG&E's 2023 GRC data presented here is subject to change pending a decision in the GRC proceeding.

296 While the CARE program provides access to utility services at a reduced rate, it does not address the issue of whether services are affordable, particularly for customers just above the qualifying income limit.

297 Highlighting is used here as this is an excerpt from PG&E's testimony. Climate Zone R includes Fresno County and other areas in the San Joaquin Valley.

Climate Zone R, or Territory R,[298] is highlighted because the data shows an AR20 value greater than 15 percent across all data years,[299] with 15 percent being identified as the demarcation value above which electricity affordability concerns are considered most severe.[300] An AR20 value greater than 15 percent indicates there are pockets within the climate zone[301] in which a representative household pays more than 15 percent of its discretionary income[302] for essential electric service.[303]

Table 29: PG&E Electric AR20, Non-CARE Customers
(2021 Actual, 2023 – 2026 Projected)

	2021	2023		2024		2025		2026		Total
	AR20	AR20	Incremental Change (%)	AR20	Incremental Change (%)	AR20	Incremental Change (%)	AR20	Incremental Change (%)	Change Over 2021 (%)
	(A)	(B)	(B) - (A)	(C)	(C) - (B)	(D)	(D) - (C)	(E)	(E) - (D)	(E) - (A)
Territory P	13.6%	15.4%	1.8%	15.6%	0.2%	15.7%	0.0%	15.5%	-0.1%	1.9%
Territory Q	8.3%	9.4%	1.1%	9.5%	0.1%	9.5%	0.0%	9.4%	-0.1%	1.1%
Territory R	15.3%	17.4%	2.1%	17.7%	0.3%	17.7%	0.1%	17.6%	-0.1%	2.3%
Territory S	10.4%	11.8%	1.4%	12.0%	0.2%	12.0%	0.0%	11.9%	-0.1%	1.5%
Territory T	8.9%	9.9%	0.9%	10.1%	0.2%	10.0%	0.0%	9.9%	-0.1%	1.0%
Territory V	13.4%	15.3%	1.9%	15.6%	0.3%	15.7%	0.1%	15.6%	-0.1%	2.1%
Territory W	11.9%	13.4%	1.5%	13.6%	0.2%	13.6%	0.0%	13.4%	-0.1%	1.6%
Territory X	4.6%	5.2%	0.6%	5.2%	0.0%	5.2%	0.0%	5.2%	-0.1%	0.5%
Territory Y	9.2%	10.5%	1.3%	10.7%	0.1%	10.7%	0.0%	10.6%	-0.1%	1.3%
Territory Z	7.2%	8.1%	0.9%	8.1%	0.1%	8.1%	0.0%	8.0%	-0.1%	0.8%

The Staff Proposal also recommends that utilities present a breakdown of the AR20 values by Public Use Microdata Areas (PUMA)[304] for climate zones with a current or proposed AR20 greater than the

[298] PG&E uses "territory" or "baseline territory" interchangeably with "climate zone" in its testimony.

[299] Other climate zones showing AR20 values greater than 15 percent are Climate Zone P (2023 – 2026) and Climate Zone V (2023 – 2026).

[300] *See* Affordability Metrics Implementation Staff Proposal for discussion of the 2019 Annual Affordability Report electric AR20 demarcation value.

[301] These sub-climate zone pockets are identified by Public Use Microdata Areas (PUMA) which are Census Bureau-defined geographic areas that are comprised of multiple census tracts. PUMAs are delineated by metropolitan areas and other "meaningful geographies," yielding areas with similar socioeconomic profiles. There are 265 PUMAs in California. Depending on population density, a single PUMA may contain several less populous counties or cover just a portion of a more populous county.

[302] Discretionary income defined as income after housing and other essential utility services are deducted from the household's income.

[303] D.20-07-032 adopted the use of electric baseline pricing and baseline quantity for determining essential electric utility service charges.

[304] AR20 and AR50 results by climate zone are constructed from PUMAs.

affordability demarcations in the most recent Annual Affordability Report.[305] Table 30 shows the 2021 actual, and 2023 through 2026 projected electric AR20s for Non-CARE customers at the climate zone level, broken down into constituent PUMA geographical areas, and PG&E's ten highest electric AR20 metric values in the year 2026.[306]

Table 30 highlights Climate Zone R to illustrate several PUMAs with high electric AR20 values; it is only by looking further down into the PUMAs that constitute a climate zone that names of locations that may be experiencing acute affordability concerns begin to emerge. In this case, for electric Non-CARE customers at the 20th percentile of the income distribution,[307] these areas are:

- PUMAs 01903, 01904, and 01905: Fresno County—Fresno City (East Central, Southwest, Southeast)
- PUMA 02903: Kern County—Bakersfield City (Northeast)

---

305 The most recent Annual Affordability Report, at the time PG&E submitted its affordability metrics testimony, shows the affordability demarcation value for electric service (i.e., the observed inflection point in the distribution of electric AR20 values) to be an AR20 of 15 percent or greater. The report is available here.

306 Housing unit data is also provided, but does not represent specific households. This data is an estimate of the number of housing units at the PUMA level based on an estimate of the number of housing units in the underlying data, which is at census tract level.

307 Household income at the 20th percentile of the income distribution for the PUMA based on an estimate of household income in the underlying data, which is at census tract level.

Table 30: PG&E Electric AR20 at PUMA Level, Non-CARE Customers
(Top-Ten Results, Climate Zone R Highlighted, 2021 Actual, 2023 & 2026 Projected)

PUMA	County/City	Climate Zone	# Housing Units	AR20 - Non-CARE		
				2021	2023	2026
07503	San Francisco County (Central)--South of Market & Potrero PUMA	PG&E T	73,967	43.3%	47.1%	49.3%
01903	Fresno County (Central)--Fresno City (East Central) PUMA	PG&E R	37,586	34.9%	39.5%	40.9%
00701	Butte County (Northwest)--Chico City PUMA	PG&E P	793	27.6%	31.6%	32.6%
07702	San Joaquin County (Central)--Stockton City (South) PUMA	PG&E S	51,947	26.1%	30.0%	31.2%
01904	Fresno County (Central)--Fresno City (Fresno City Southwest) PUMA	PG&E R	50,965	25.8%	29.4%	30.2%
01905	Fresno County (Central)--Fresno City (Fresno City Southeast) PUMA	PG&E R	36,520	21.5%	24.5%	24.9%
02903	Kern County (Central)--Bakersfield City (Northeast) PUMA	PG&E R	86	21.6%	24.5%	24.9%
00701	Butte County (Northwest)--Chico City PUMA	PG&E S	48,892	20.5%	23.4%	24.1%
00104	Alameda County (North Central)--Oakland City (South Central) PUMA	PG&E X	62	21.4%	23.6%	23.4%
02903	Kern County (Central)--Bakersfield City (Northeast) PUMA	PG&E W	56,034	18.5%	21.0%	21.3%

Table 31, which shows the same data as Table 30 but for CARE customers rather than non-CARE customers, indicates that affordability concerns for customers who receive a reduced bill under the CARE program are largely unabated, with AR20s exceeding 15 percent in most PUMAs through 2026.

Table 31: PG&E Electric AR20 at PUMA Level, CARE Customers
(Top-Ten Results, Climate Zone R Highlighted, 2021 Actual, 2023 & 2026 Projected)

PUMA	County/City	Climate Zone	# Housing Units	AR20 - CARE		
				2021	2023	2026
07503	San Francisco County (Central)--South of Market & Potrero PUMA	PG&E T	73,967	26.7%	28.9%	29.9%
01903	Fresno County (Central)--Fresno City (East Central) PUMA	PG&E R	37,586	23.0%	26.6%	27.3%
00701	Butte County (Northwest)--Chico City PUMA	PG&E P	793	17.6%	20.1%	20.7%
07702	San Joaquin County (Central)--Stockton City (South) PUMA	PG&E S	51,947	16.7%	19.1%	19.7%
01904	Fresno County (Central)--Fresno City (Fresno City Southwest) PUMA	PG&E R	50,965	16.5%	18.8%	19.3%
01905	Fresno County (Central)--Fresno City (Fresno City Southeast) PUMA	PG&E R	36,520	13.8%	15.7%	15.9%
02903	Kern County (Central)--Bakersfield City (Northeast) PUMA	PG&E R	86	14.0%	15.8%	16.0%
00701	Butte County (Northwest)--Chico City PUMA	PG&E S	48,892	13.1%	15.0%	15.3%
00104	Alameda County (North Central)--Oakland City (South Central) PUMA	PG&E X	62	13.6%	14.9%	14.8%
02903	Kern County (Central)--Bakersfield City (Northeast) PUMA	PG&E W	56,034	11.9%	13.5%	13.7%

It is important to note that the projected data for 2026 does not consider the outcomes of other PG&E proceedings.