2024 SENATE BILL 695 REPORT

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

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California Public
Utilities Commission

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I. EXECUTIVE SUMMARY

The California Public Utilities Commission (CPUC) issues this 2024 Senate Bill (SB) 695 Report pursuant to Public Utilities Code Section 913.1. This report outlines recommendations to limit cost and rate increases for California's Investor-Owned Utilities (IOUs) while aligning with the state's energy and environmental goals. Additionally, the IOUs are mandated to propose measures to control costs and rate increases.[1]

The CPUC's mission is to ensure that California IOU customers receive safe, reliable, and clean utility service at just and reasonable rates. Determining these rates involves complex electric and gas ratemaking processes, which scrutinize various IOU requests for capital investments, expenses, and essential costs and distill them into an approved revenue requirement collected from customers. The CPUC continues to work to further the goals of affordable rates and bills as well as safe, reliable, and clean utility service.

California is leading the way on clean energy deployment and the rapid decarbonization of the electricity sector to reach the state's ambitious climate change goals. The IOUs have achieved an energy mix that is largely zero carbon due to California's landmark policies over the past decades that have helped phase out coal power plants and required IOUs to invest early in clean energy technologies such as solar, wind and storage to provide their customers with increasingly clean electricity. Although residual reliance on natural gas at times when clean resources are not available remains, opportunities to harness new clean energy resources are on the horizon, with offshore wind and long-duration energy storage developing as promising potential additions to California's interconnected grid.

Today, all CPUC-jurisdictional load serving entities in California—including IOUs, community choice aggregators, and direct access providers—are procuring only clean energy on behalf of their customers. These numerous clean energy projects are built to serve each of their customers, including low-income households, tribal communities and homes and businesses in disadvantaged communities, to provide the most cost-effective clean energy for each customer and a direct path to reduce reliance on California's remaining gas plants, while maintaining reliability. The IOUs, community choice aggregators, and direct access providers are collectively on track to meet California's ambitious greenhouse gas and zero carbon targets and renewables portfolio standard, providing significant benefits to the state by reducing fossil fuel use and incubating clean energy technologies and bringing them to scale.

[1] Public Utilities Code §913.1 requires the CPUC to publish recommendations that can be undertaken over the succeeding 12 months to limit California's IOU cost and rate increases consistent with the state's energy and environmental goals. *See* Public Utilities Code §913.1(b): In preparing the report required by subdivision (a), the commission 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 cost and rate increases.

Because electricity ratepayers are the source of funding to repay any investment in energy and the infrastructure it relies on, California's policy framework for funding the build out and procurement of clean energy is designed to keep costs as low as possible through competitive solicitations that result in least-cost, best-fit bids from privately owned electricity generators. Although repayment of legacy investments is an ongoing component of energy bills, costs associated with this competitive clean energy procurement have been relatively stable as we continue to make great strides toward achieving our net zero goals while maintaining safety and reliability.

Importantly, we are in a transformational period for the electric grid, with transportation and building electrification set to accelerate at an exciting pace that will put California further on the path to our net zero goals. This transformation will lead to significant public benefits as fewer cars, trucks, and buildings rely on fossil fuels for energy. Our existing distribution system will need significant upgrades to accommodate the anticipated load from electric vehicles, electric heat pumps, and other electric appliances.

The integration of this increased electricity demand comes with distribution system planning challenges and costs, but also opportunities to manage costs by siting new load where capacity already exists. It also comes with opportunities to share system costs among more units of electricity from customers who electrify, which will put downward pressure on everyone's electric rates. While costs to upgrade the electric distribution system will be in the tens of billions of dollars, this strategic investment will also be paired with significant cost savings from reduced spending on gas and petroleum as residential and business customers electrify their end uses. Efficient short- and long-term planning, federal grants, and mitigation efforts, including strategic placement and use of distributed energy resources, will be key to guiding future grid investments.

While we are on track to meet growing load and our climate change goals, cost containment is essential. This report finds that utility costs continue to outpace inflation due to multiple cost pressures. The largest contributors to recent rising electricity rates are wildfire risk reduction costs and Net Energy Metering (NEM) program costs. Transportation and building electrification-related distribution capacity upgrade costs are not evaluated in this report since these emerging costs are currently under review in active general rate cases and will be entering rates soon.

Wildfire mitigation costs have climbed since 2021 and are projected to continue their upward trend due to climate change-induced risks. The order of magnitude of these costs shows the scale of the problem that California is facing: climate change is escalating, with stronger storms, hotter temperatures, and conditions that increase the risk of catastrophic wildfire. While these expenditures are crucial for maintaining essential services and a safe and reliable grid, we are taking action to contain costs through the implementation of wildfire self-insurance, continued scrutiny of and better planning for IOU vegetation management expenses, and securitization of capital spending to spread costs out over longer time horizons.

The NEM program is the other large contributor to rising electricity rates. For customers without rooftop solar, NEM program costs account for between 11 and 25 percent of their electricity bill, depending on the IOU. This translates to an average monthly cost burden of roughly $20 to $35 for customers without rooftop solar. The new Net Billing Tariff (NBT) adopted in 2022 reduces the growth of future costs by lowering the amount customers are required to pay to new rooftop solar customers. The NBT does this by more closely aligning the compensation rooftop solar customers receive with the value that their system provides to other customers. However, the cost burden to customers without rooftop solar is not fully mitigated by the new Net Billing Tariff (NBT). Additionally, the current costs associated with legacy NEM 1.0 and 2.0 installations will remain in electricity bills for many years, continuing to cause rates to increase for customers without rooftop solar.

Given multiple cost pressures that are causing rates to rise, it is imperative that we make strategic investments as cost effectively as possible to meet growing demand for clean electricity. A focus on low-income customers, tribal communities, and disadvantaged communities is vital. As we enter this transformational chapter for our clean electricity system, the CPUC is taking multiple actions to responsibly cut costs, enhance equity, and put downward pressure on rates while maintaining safety and reliability.

Multiple Actions Are Underway to Mitigate Electricity and Natural Gas Costs and Put Downward Pressure on Rates

The CPUC is committed to ensuring just and reasonable rates while promoting reliable, affordable, and clean utility services. To achieve these objectives, the CPUC is:

- **Mitigating Cost Increases**: Implementing measures to control rising costs.
- **Focusing on Equitable Cost Allocation**: Seeking ways to distribute energy costs more fairly.
- **Planning for Strategic Investments**: Shaping investments to advance climate goals and grow load at least cost.

The table below lists some of the many actions that are underway to mitigate costs, put downward pressure on rates, and improve affordability through ratepayer savings.

Actions Underway to Limit Costs and Save Ratepayers Money

Vegetation Management Spending Caps Limit Costs While Maintaining Safety Requirements

- Decision (D.)21-08-036 and D.23-11-069 imposed "soft caps" on vegetation management costs to limit the IOUs' ability to recover vegetation management costs above authorized amounts without a reasonableness showing.[2]
- Any unused authorized amount is to be returned to ratepayers through the balancing account ratemaking mechanism.

Wildfire Self-Insurance Produces Ratepayer Savings

- Cost of commercial market wildfire insurance has escalated in recent years.
- D.23-01-005 and D.23-05-013 approved proposals for PG&E and SCE to implement wildfire self-insurance, estimated to have resulted in a $467 million ratepayer savings impact in 2023.[3]
- Similar savings are anticipated for future years.

New Flat Rate Benefits Low-Income Customers, Customers That Electrify And Those Most Impacted By Climate Change-Induced Heat Events

- D.24-05-028 moved some existing fixed costs into a "flat rate" line item on bills, aligning California's bill structure with other state and nationwide utility flat rates and lowering California's consumption-based electricity rates.[4]
- Customers enrolled in low-income assistance programs will benefit from a discounted flat rate ranging from $6 to $12 per month.[5] All customers who electrify their home and/or vehicles and customers who are most vulnerable to the impacts of extreme heat events will also benefit.

Net Billing Tariff (NBT) Limits Cost Increases

- D.22-12-056 reduces electricity bills for IOU customers by reducing the amount customers pay to other IOU customers who install solar or solar-plus-storage systems in the future.[6]
- While Net Energy Metering (NEM) 1.0 and 2.0 programs decrease electricity bills for customers participating in the programs, they increase electricity bills for all other customers.
- The decision does not change the ongoing increased costs that customers pay for other customers to remain on the NEM 1.0 and NEM 2.0 tariffs. It also does not eliminate future bill increases that occur when individuals and businesses install rooftop solar and solar-plus-storage systems, even under the NBT tariff.

Virtual Net Billing Tariff (VNBT) and NBT Aggregation Subtariff Limit Cost Increases

- D.23-11-068 reduces electricity bills for IOU customers by reducing the amount customers pay to other IOU customers who install solar or solar-plus-storage systems using the VNBT and NBT Aggregation programs compared to previous Virtual Net Energy Metering (VNEM) and Net Energy Metering Aggregation (NEMA) programs.[7]
- While VNEM and NEMA programs decrease electricity bills for customers participating in the programs, they increase electricity bills for all other customers.

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[2] *See* D.21-08-036 issued in A.19-08-013 and D.23-11-069 issued in A.21-06-021.
[3] *See* D.23-01-005 issued in PG&E's 2023 General Rate Case (A.21-06-021) and D.23-05-013 issued in SCE's 2021 General Rate Case (A.19-08-013).
[4] *See* D.24-05-028 issued in proceeding R.22-07-005.
[5] Along with customers enrolled in low-income assistance programs, customers residing in deed-restricted affordable housing with incomes at or below 80 percent of the area median income will qualify for a discounted flat rate.
[6] *See* D.22-12-056 in proceeding R. 20-08-020.
[7] *See* D.23-11-068 in proceeding R.20-08-020.

• The decision does not change the ongoing increased costs that customers pay for other customers to remain on the NEM 1.0 and NEM 2.0 tariffs. It also does not eliminate future bill increases that occur when other customers install rooftop solar and solar-plus-storage systems using the new tariffs.
Revision of Electric Rule 20 Prevents Ratepayers From Funding Inequitable Investments • The Rule 20A program subsidizes the undergrounding of power lines for aesthetic purposes in localized areas and benefits few ratepayers at the expense of the many ratepayers. • D.23-06-008 discontinues and phases down the Rule 20A Program by 2033 to prevent ratepayers from funding inactive and inequitable infrastructure investments.[8] • The action is estimated to save $74 million annually through 2033.
Intervention In Transmission Owner Rate Cases Saves Ratepayers Money • The FERC Cost Recovery Team and Legal Division work together to intervene in Transmission Owner rate cases at FERC on behalf of ratepayers. • Ratepayer savings are ongoing and estimated to be $5 billion since 2018.
Transmission Project Review (TRP) Process Increases Transparency Of Costs • The TPR Process is modeled after stakeholder processes negotiated in previous transmission owner rate case settlements at FERC and provides transparency of the IOUs' FERC jurisdictional transmission projects that exceed $1 million in costs.[9] • While not always quantifiable, savings from previous FERC-derived processes between 2020 and 2023 resulted in quantified long-term savings to ratepayers of between $500 million and $1 billion. • As the TPR Process is more robust than those earlier processes, the affordability benefits to ratepayers are expected to be at least as great.
Implementation of FERC Order Saves Ratepayers Money • AB 209 reaffirms and clarifies that IOU participation in the CAISO is ordered by the CPUC and not voluntary. This clarification confirms that the IOUs cannot collect additional costs from ratepayers as an incentive to participate in an ISO. • The Federal Energy Regulatory Commission (FERC) ruled in December 2023 that AB 209 is clear that incentives are not appropriate if an action is already mandatory. • This adder will not be allowed in future rate cases and has an estimated cost savings of $86 million in 2024.
CPUC Resolution Encourages and Enables Ratepayer Savings from Federal Programs • Resolution E-5254 encourages electric and gas IOUs to pursue federal grants under the Infrastructure Investment and Jobs Act (IIJA), the Inflation Reduction Act (IRA), and the Creating Helpful Incentives to Produce Semiconductors and Science Act (CHIPS).[10] • In October 2023, California was selected to receive up to $1.2 billion to accelerate the development and deployment of clean renewable hydrogen. • In January 2024, PG&E and the U.S. Department of Energy finalized a credit award agreement of up to $1.1 billion for Diablo Canyon as part of the IIJA's Civil Nuclear Credit Program. • The IOUs have submitted additional applications for Federal funding under these Acts, including a joint application for grid enhancing technologies (GETs) that increase electric transmission capacity, which are still pending.

[8] *See* D.23-06-008 in proceeding R.17-05-010.

[9] The TPR Process was established in Resolution E-5252.

[10] Resolution E-5254 also establishes a process to track cost recovery requests by the utilities for projects that may be funded partly by federal grants and requires quarterly reporting of planned and submitted applications to track IOU progress.

• CPUC continues to work with the IOUs and other agencies to enable federal funding to reduce rates by displacing the need for ratepayer funding for critical energy projects.
Equity Rate Base Exclusion and Optional Securitization Limit Rate Increases
• As directed by AB 1054, the annual revenue requirements approved by the CPUC preclude the IOUs from recovering a Return on Equity on $5 billion in wildfire mitigation capital costs.[11] • These equity rate base exclusions should save ratepayers as much as $2 billion over the lifetime of the assets. • AB 1054 also allows for securitization of wildfire mitigation capital spending. Securitization benefits ratepayers by allowing the securitized bonds to obtain a lower interest rate than would otherwise be available to finance WMP capital expenditures.[12] • To date, the CPUC has authorized $10.9 billion in securitization bonds under AB 1054 and SB 901.[13]
SGIP Equity Budget Allocation Will Reduce Participating Low-Income Customer Bills
• D.24-03-071 allocated $280 million in funding from the Greenhouse Gas Reduction Fund to the SGIP Residential Solar and Storage Equity budget consistent with the requirements of AB 209.[14] • Roughly 8,300 low-income customers, including tribal customers, will receive funding to offset the upfront costs of battery storage or battery storage paired with rooftop solar through this SGIP Residential Solar and Storage program.
New Penalty Structure For Natural Gas Helps Manage Price Volatility
• D.22-04-42 made the SoCalGas Operational Flow Order (OFO) winter noncompliance charges effective year-round and also made the OFO penalties uniform for both SoCalGas and PG&E.[15] • The OFO rules approved in D.22-04-042 help better manage gas price volatility, which can impact gas and electric bills. • The savings from price spikes that did not occur cannot be easily quantified. PG&E will provide an estimate of the O&M savings from the reclassification in its next GRC.
Pipeline Reclassification Results in Reduced System Costs
• D.23-12-003 approved the reclassification of 600 miles of pipeline from transmission to distribution and set out criteria for future de-ration of transmission lines.[16] • This pipeline reclassification will result in lower overall system costs, which will benefit customers.
Increase in Natural Gas Inventory Levels Reduce Likelihood of Price Spikes
• In the Aliso Canyon proceeding, the CPUC is considering the potential to reduce or eliminate usage of the Aliso Canyon natural gas storage facility in response to the historic gas leak in 2015-16. • The California Geologic Energy Management Division (CalGEM) set the maximum safe inventory at Aliso Canyon at 68.6 billion cubic feet (Bcf), down from its pre-leak level of 86 Bcf.

[11] AB 1054 excludes the first $5 billion of the large IOUs' Wildfire Mitigation Plan (WMP) capital spending from earning a return on equity. (AB 1054, Section 18). This limits rate increases directly by eliminating the investor return portion of the return on rate base of $5 billion in WMP capital spending. *See* Chapter IV, Wildfire-Related Costs section for each IOU's total equity rate base exclusion amount.

[12] *See* Chapter IV, Wildfire-Related Costs section for specific Financing Order Application and Decision numbers.

[13] Under PG&E's bankruptcy plan and SB 901, the CPUC also authorized $7.5 billion in securitization (SB 901, Section 32).

[14] *See* D.24-03-071 issued in proceeding R.20-05-012. AB 209 directs the CPUC to use funds appropriated by the California Legislature to provide eligible low-income residential customers, including those receiving service from a local publicly owned electric utility, to install behind-the-meter solar, storage, or solar and storage systems. (AB 209, Section 26).

[15] *See* D.22-04-042 in proceeding R.20-01-007.

[16] *See* D.23-12-003 in proceeding R.20-01-007.

- In D.23-08-050, the CPUC increased the maximum inventory from 41.16 Bcf up to the estimated CalGEM safety level maximum of 68.6 Bcf.[17] By increasing the inventory level at Aliso Canyon, the CPUC reduced the likelihood of gas and electric price spikes. which California experienced during winter 2022-23 and which did not occur during winter 2023-24 after storage levels were increased.
- The proceeding continues to plan for the reduction or elimination of the use of Aliso Canyon concurrently with efforts to reduce gas demand in California.

Elimination of Subsidies for Gas Line Extensions and Electric Line Extensions Saves Ratepayers Money

- To support building decarbonization goals, D.22-09-026 eliminated ratepayer-funded subsidies for gas line extensions and D.23-12-037 further eliminated electric line extensions for buildings constructed with gas lines.[18]

Key Findings in the 2024 SB 695 Report

The Largest Contributors to Rising Electricity Rates Are Wildfire Mitigation Costs and Net Energy Metering

Wildfire Mitigation Costs

Wildfire mitigation costs have climbed since 2021 and are projected to continue rising due to climate change-induced risks. In 2021, significant wildfire-related operating expenses, including vegetation management efforts and wildfire liability insurance coverage, began to push up rates.[19] Wildfire costs are now a significant portion of the utilities' total revenue. At year-end 2023, wildfire-related costs make up 18 percent of PG&E's total revenue requirement, 12 percent of SCE's total revenue requirement, and 9 percent of SDG&E's total revenue requirement. [20]

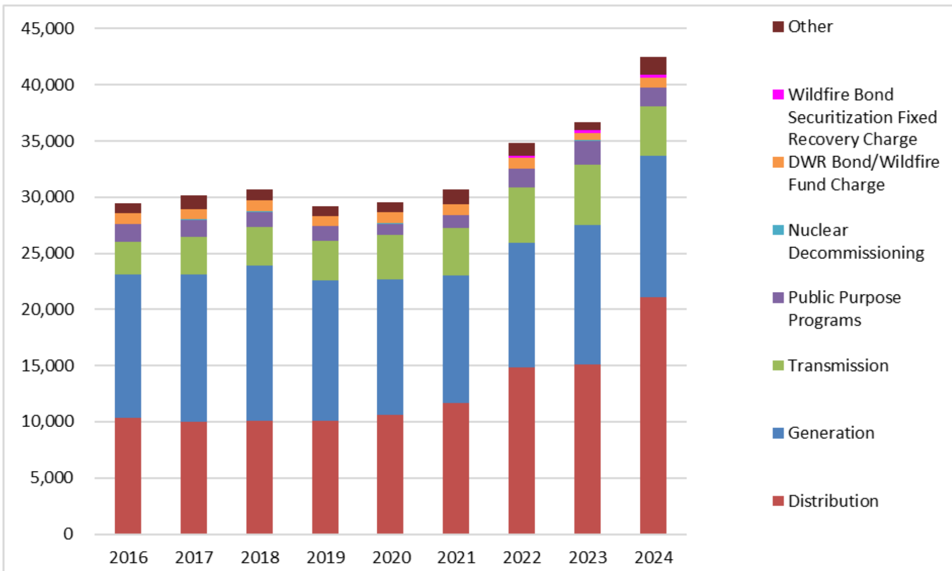
Over the next several years, wildfire mitigation costs, driven in part by climate change, are projected to continue their upward trend. Wildfire mitigation spending is presented in each electric IOU's wildfire mitigation plan (WMP), which describes in detail the level of wildfire risk in their service territory, how IOUs intend to address those risks, and projected plan costs.[21] Recent WMPs for the large electric IOUs show significantly higher planned spending for the 2023 – 2025 cycle than actual

[17] *See* D.23-08-050 in proceeding I.17-02-002.
[18] *See* D.22-09-026 and D.23-12-037, both in proceeding R.19-01-011.
[19] Operating expense includes operations and maintenance (O&M) expense and administrative and general (A&G) expense. O&M expense include all labor and non-labor costs for a utility's operation and maintenance of its generation, distribution, and transmission infrastructure. A&G expense include costs such as liability insurance and non-infrastructure personnel costs.
[20] Includes catastrophic events costs, which are substantially related to fire-related events but may include costs for other non-wildfire related events such as severe storms and wind events.
[21] *See* each IOU's 2023 – 2025 Base WMP and 2025 WMP Update at: https://energysafety.ca.gov/what-we-do/electrical-infrastructure-safety/wildfire-mitigation-and-safety/wildfire-mitigation-plans/2023-wildfire-mitigation-plans/.

spend in the previous 2020 - 2022 cycle.[22] The order of magnitude of these costs shows the scale of the problem that California is facing: climate change is escalating, with stronger storms, hotter temperatures, and conditions that increase the risk of catastrophic wildfire.

The figure below shows the combined total of all revenue requirements for PG&E, SCE, and SDG&E, classified by the type of rate component through which the revenue is collected.

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



The distribution revenue requirement has significantly grown over time, with a substantial increase occurring between January 1, 2023 and January 1, 2024. This increase in distribution revenue requirement from January 1, 2023 to January 1, 2024 is mainly due to PG&E's distribution revenue requirement increasing by about 78 percent. By comparison, SCE's distribution revenue requirement over this time period increased by about 17 percent, and SDG&E's distribution revenue requirement decreased by about 1 percent.

Roughly three-quarters of this increase in PG&E's distribution revenue requirement is attributed to costs approved in PG&E's 2023 GRC.[23] These types of costs include power lines, poles, transformers, repair crews and emergency services, as well as certain wildfire mitigation costs related to grid reliability and safety, including liability insurance. The other approximately one-quarter of this

[22] Costs are about $26.2 billion projected for the 2023 – 2025 cycle and about $20.7 billion incurred in the previous 2020- 2022 cycle. Stand-alone 2019 WMPs were also submitted; a review of the 2022 WMPs shows 2019 costs incurred of about $6.2 billion.

[23] *See* D.23-11-069. The late implementation of PG&E's 2023 GRC test year revenue requirement on January 1, 2024, is included in this increase. The test year is the first year in the new GRC cycle and if its implementation is delayed to a later year, the revenue requirement that would have been collected in the test year is included with the subsequent year's revenue requirement. Half of the delayed 2023 test year revenue requirement is to be collected in 2024.

increase is primarily due to wildfire mitigation and catastrophic event costs approved in several PG&E applications filed outside of the GRC proceeding process. These costs were incurred over several years, beginning in 2017, but not recovered in rates until 2024.

Other revenue requirement components in the figure above have remained relatively stable between January 1, 2023, and January 1, 2024. The generation rate component reflects the recovery of "purchased power costs," or the costs of contracts with third-party electricity generators. It also reflects the cost of Utility Owned Generation (UOG), consisting of fuel and other operating expenses and capital costs associated with generation plants such as nuclear, gas, and hydroelectric. The transmission rate component is set by the Federal Energy Regulatory Commission (FERC) and collects the revenue requirement associated with the utilities' assets determined to be part of the interstate transmission system. The Public Purpose Program rate component collects program funding authorized by the CPUC for Electric Program Investment Charge (EPIC), Energy Efficiency programs, Low-Income programs, and other public policy programs.[24]

While transportation electrification-related capacity upgrade costs are not evaluated in this report since they are under review in current rate cases, these costs will be entering rates soon.[25] PG&E has filed a cost recovery application related to two new pieces of legislation recently signed into law to promote timely energizations, including timing related to electric vehicle (EV) charging.[26] The build-out costs related to distribution capacity upgrades for transportation electrification and building electrification—as well as transmission capacity upgrades—are expected to be contributing factors to rate growth in the near and mid-term.

Net Energy Metering Costs

Net Energy Metering (NEM) program costs are also one of the largest contributors to rising electricity rates for customers that do not have rooftop solar. As of year-end 2023, for a typical PG&E customer without rooftop solar, NEM program costs account for 14 percent of their electricity bill. For a typical SCE customer without rooftop solar, NEM program costs account for 11 percent of their electricity bill. For a typical SDG&E customer, NEM program costs account for

[24] See the Electric Revenue Requirement section in the Background chapter for additional information.

[25] Transportation electrification-related capacity upgrade costs are currently being reviewed in active general rate cases. The phase in PG&E's 2023 GRC in which this determination is being made and SCE's 2025 GRC proceeding are both estimated to conclude after this report is prepared. PG&E's request does not break down energization-related distribution upgrades into categories such as TE-related; SCE specifically identifies TE-related distribution upgrades in its 2025 GRC application. Prior to SCE's 2025 GRC, transportation electrification-related distribution capacity upgrades were not necessarily broken out.

[26] *See* Rulemaking (R.) 24-01-018. Assembly Bill (AB) 50 (Wood, 2023) established criteria for customers to receive timely energization and potential remedies to expedite energization. Senate Bill (SB) 410 (Becker, 2023) requires the establishment of reasonable average and maximum target energization time periods in order to connect new customers and upgrade the service of existing customers to the electrical grid. PG&E is the first utility to request a ratemaking mechanism under SB 410; other utilities may also do so in the future.

up to 25 percent of their electricity bill.[27] The figure below illustrates the portion of the typical customer bill that is due to NEM program costs.

NEM Cost Portion of a Typical Residential Customer Monthly Bill (2023)

The NEM 1.0 and NEM 2.0 program increases electricity bills in two ways: (1) customers pay for the generation that is exported to the grid from another customer's NEM system at a higher rate than other available generation, and (2) customers pay for the part of bill savings experienced by NEM customers because the program allows rooftop customers to bypass their share of fixed costs to maintain the electric grid, which other customers without rooftop solar end up paying.

IOU customers without rooftop solar are paying NEM customers for the generation they send to the electric grid at a rate that exceeds the cost of generation otherwise available from the grid. NEM 1.0 and NEM 2.0 customers are compensated for electricity exported to the grid at the retail volumetric rate, which exceeds the marginal cost of avoided wholesale generation purchased for that customer. IOU customers pay this increased cost to NEM customers for 20 years after their grid interconnection dates.

The reduction in grid consumption results in a bill savings for NEM customers but increases bills for everyone else. This occurs because in California, the fixed costs of electricity services (including support for low-income customers) are primarily collected through the volumetric distribution rate component of customer bills. Customers who use less electricity pay a smaller share of these fixed costs, even though the total fixed costs are not reduced when customers reduce the volume of energy consumed. As a result, when customers reduce their bills by substituting rooftop solar

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

production for grid generation, they are reducing their share of fixed volumetric costs and that share is then paid by other customers. The fixed costs are spread across fewer units of usage and customers without NEM systems see their bills increase.

Distributed energy resources, including batteries, electric vehicles, and heat pumps, are a part of California's overall electricity future, and new policies are helping to send improved price signals to these resources so that they can best support electric grid needs. From April 2023 on, new rooftop solar customers—or prior NEM customers at the end of their 20-year legacy interconnection periods—will receive compensation through the new Net Billing Tariff (NBT), which provides compensation that is more aligned with the value of the generation the systems provide to other customers and includes more generous subsidies for systems with battery storage compared to rooftop solar. This cost increase, however, is not fully mitigated by the new Net Billing Tariff (NBT).

Utility Costs Are Trending Above Inflation

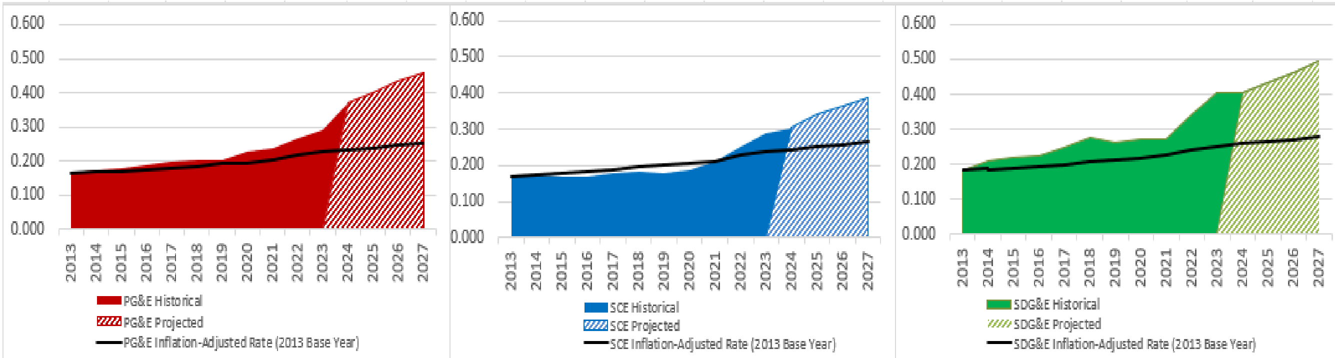
Beginning in 2021, rate increases for all of the three major electric IOUs bundled customers began to outpace inflation for the first time, particularly affecting bundled residential customers.[28] This report finds that electric rates are expected to continue increasing above inflation through 2027, the latest year for which we have accurate forecasts.[29] Historical and forecasted rate trends are illustrated in the figure below.[30]

[28] Bundled IOU customers receive all services — generation, transmission, and distribution services — from the IOU, compared to for example community choice aggregator customers that receive only transmission and distribution services from the IOU.

[29] Forecasts are conducted through 2027 because projected revenue changes that inform forecasts are based on rolling four-year-cycles, which generally align with at least one utility's general rate case.

[30] Projected rates in this report are forecasts, and therefore subject to material change as assumptions change. Further, forecasts are based on forward-looking estimates that are not historical facts. Forecasts are for illustrative purposes only and solely for use in this report.

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



Average annual electric rate increases are forecasted to be 10.8 percent for PG&E, 6.8 percent for SCE, and 5.6 percent for SDG&E, compared to an assumed inflation rate of 2.6 percent. By 2027, residential average rates are forecast to be approximately 80 percent higher than they would have been if rates for PG&E and SDG&E had grown at the rate of inflation since 2013, and 50 percent higher for SCE.

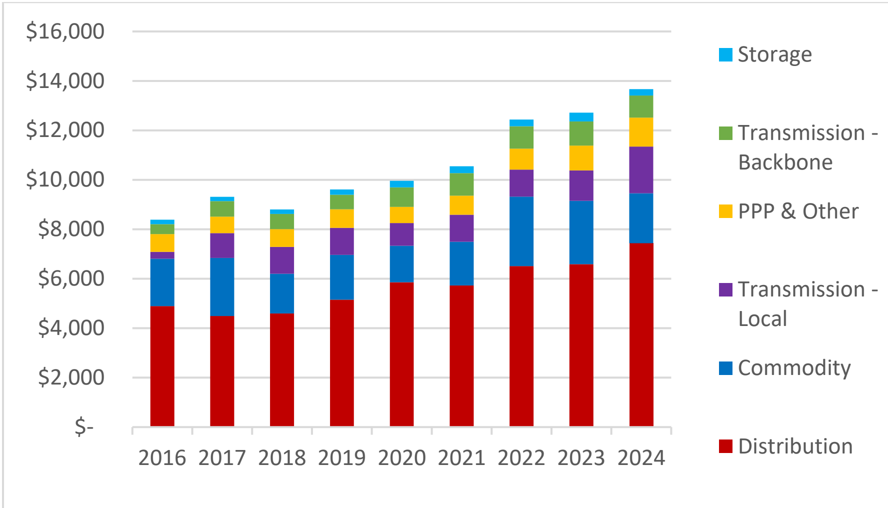
Natural Gas Costs Are Steadily Increasing, Driven By Increased Transmission and Distribution Pipeline Inspection and Safety Compliance Costs

Year-over-year revenue requirements for natural gas utilities are set to increase, driven by safety and reliability projects and higher inflation. For natural gas utilities, 2024 year-over-year revenue requirements increased by 5.2 percent (to $6.44 billion) for SoCalGas, 10.9 percent (to $6.26 billion) for PG&E, and 2 percent (to $0.967 billion) for SDG&E.

The current gas utility cost drivers are associated with the safety, maintenance and reliability work conducted to inspect gas transmission and distribution pipelines, to detect and repair gas leaks and comply with federal and state safety regulations. A higher inflation rate was also a significant cost driver. However, a forecasted decrease to the natural gas commodity cost, which corresponds to 12 to 19 percent of the gas utilities' respective 2024 revenue requirements, has offset some of the revenue impact year-over-year. In the future, California's declining gas consumption due to the state's conservation and electrification efforts is expected to add upward pressure on the natural gas transportation rates.

The figure below shows the revenue requirement distribution among the various gas cost components.

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



Conclusion

As we face the threat of climate change and increasingly frequent extreme weather events, the need to rapidly decarbonize is clear. A lot of important work needs to be done to meet this global challenge, including quickly reducing the remaining reliance on natural gas in our electricity supply, upgrading the distribution system, and electrifying our homes and vehicles at an unprecedented scale. This challenge comes with opportunities to invest strategically, implement cost effective solutions, and contain costs equitably to provide all customers with equal access to clean, reliable, safe energy. As the CPUC's 2024 SB 695 Report highlights, many factors are contributing to increased utility rates, and the CPUC is taking action to mitigate costs, put downward pressure on rates, and promote equity during this significant transformation of the energy sector in California.

II. BACKGROUND

In cost-of-service rate regulation, the regulator determines the total amount of money that must be collected in rates for the utility to recover its reasonable and necessary costs plus the opportunity to earn a reasonable return on investments. The cost-of-service regulatory model aims to provide universal access to safe and reliable electricity while ensuring regulated monopoly utility service providers charge a fair price.

Electric Ratesetting Proceedings

Utilities file detailed descriptions of the costs of providing service (also referred to as "revenue requirements") and request authorization to collect revenue requirements in various ratesetting proceedings. Most utility costs, other than the cost of procuring fuel and purchased power,[31] are generally addressed in General Rate Case (GRC) proceedings.[32] GRCs are forward-looking, as IOUs forecast and estimate their anticipated costs to operate their respective utility. In GRC proceedings, the CPUC sets a pre-specified revenue requirement for the first year in the cycle, or "test year," with formulaic adjustments for the subsequent "attrition years" until the next GRC cycle commences.

In addition to forecasting costs for recovery, GRCs may include requests for recovery of costs that have already been incurred i.e., recorded costs in balancing accounts and memorandum accounts.[33] A balancing account is established to record certain authorized costs for recovery through rates and to ensure the revenue collected matches the authorized amounts. Balancing account revenue balances are to be returned to ratepayers if the account is over-collected, and in some circumstances additional revenue can be recovered from ratepayers if the account is under-collected.[34] Memorandum accounts are similar to balancing accounts except they record costs not yet authorized and are subject to reasonableness reviews by the CPUC and may or may not be recoverable through rates. Memorandum accounts generally reflect unanticipated costs such as the cost of restoring service after a catastrophic event or the costs associated with new legislation enacted after a utility's GRC proceeding.

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-emission vehicles and grid modernization, and as a result, substantial costs have been recently authorized in proceedings for transportation electrification and energy storage.

[31] Most energy procurement costs are addressed in annual Energy Resource Recovery Account (ERRA) Forecast proceedings. ERRA costs are pass-through expenses; the utility receives no mark up or profit on these costs.
[32] For more detailed descriptions of how GRC proceedings and Energy Resource Recovery Account (ERRA) proceedings authorize utility revenue requirements *see* the 2023 Assembly Bill (AB) 67 Report.
[33] Cost recovery of balancing and memorandum account balances may also occur outside GRC proceedings.
[34] Under-collected balancing account balances can only be recovered from ratepayers if the balancing account is a two-way balancing account. Under-collections in one-way balancing accounts can not be recovered from ratepayers.

Electric Revenue Requirement

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

The **generation** rate component collects the revenue requirement corresponding to generation portfolio costs. This rate component recovers the cost of Utility Owned Generation (UOG), consisting of fuel and other operating expense and capital costs associated with generation plants such as nuclear, gas, and hydroelectric. IOUs also recover "purchased power costs" which represent the costs of contracts with third-party electricity generators. The incremental cost impact of renewable contracts to meet the Renewables Portfolio Standard (RPS) and greenhouse gas (GHG) costs[35] is also reflected in generation rates.

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

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[35] 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. A portion of the allowance proceeds are returned to residential customers via the California Climate Credit, applied to the distribution component of customer bills twice per year.

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

Other rate components include:

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

The **PPP** rate component collects program funding authorized by the CPUC for Electric Program Investment Charge (EPIC), Energy Efficiency, Low-Income programs, and other public policy programs.[36] **NSG** charges recover the costs of "new generation" assets the IOUs procure to maintain system reliability. **CTC** recover above-market costs associated with power purchase contract obligations that resulted from electric industry restructuring pursuant to Public Utilities Code Section 367(a). **ND** costs flow into a trust maintained for assurance that complete decommissioning activities for nuclear facilities will be undertaken and are recovered separately in the ND rate component. **WFC** recover costs to fund the wildfire fund created by Assembly Bill (AB) 1054 (Holden, 2019).[37] Wildfire Bond Securitization **FRC** are charges for certain wildfire capital costs recovery bonds that AB 1054 permits to be securitized through a CPUC financing order rather than being financed through the more traditional unsecured bond offerings.[38] The **TRAC** reflects the cost shift that resulted from capped residential tiered rates previously legislated under AB 1X and SB 695.[39] The **ECRA** rate component is used to return amounts to customers resulting from settlement agreements with sellers of energy to resolve energy claims related to the Western Energy Crisis of 2000-2001 ("FERC energy crisis refund").[40]

Revenue Collection by Operating Expenses and Capital Expenditures

To fully understand utility costs, it is necessary to understand the difference between two categories of revenue requirement: operating expenses and capital expenditures. Operating expense and capital-

[36] For more detailed descriptions of PPP, *see* the 2023 Assembly Bill (AB) 67 Report.

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

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

[39] Applies to SDG&E only.

[40] Applies to PG&E only.

related costs authorized for recovery during ratesetting proceedings must be converted to revenue requirement to be recovered from ratepayers through rates.

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

Capital-related costs include: (1) capital expenditure depreciation expense[41] recovered over a long period of time as the underlying asset depreciates and (2) an authorized profit, consisting of a return on capital invested by utility in assets, or "return" on the net book value[42] of the utility's assets known as "rate base." Capital expenditure depreciation expense along with return on rate base comprise the utility's **capital-related revenue requirement.**

When net book value increases,[43] which has generally been the case for PG&E, SCE, and SDG&E, rate base increases.[44] to produce **the return on rate base revenue requirement**[45] Increases in rate base over time thus directly result in increases in the return on rate base revenue requirement.[46]

REVENUE REQUIREMENT

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

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

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

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

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

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

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

[44] Each IOU's rate of return on rate base is authorized in a cost of capital proceeding.

[45] Return on rate base revenue requirement is a type of financing cost.

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

requirement have a larger immediate impact on rates than costs resulting in capital-related revenue requirement.

Electric Bundled Rates

Historical rate trends allow comparison of how an IOU's rates track another metric, inflation, over time. The reason inflation is typically used as a benchmark for electric rate growth is because it has traditionally been assumed that household incomes rise at about the rate of inflation, thus if electric rates increase at the same rate then the affordability of electric service should remain unchanged for the average household. However, it should be noted that while inflation generally affects the costs underlying the utility's revenue requirement, rates and bills are impacted by other factors, such as wholesale natural gas prices, high interest rates, and supply chain challenges.

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[47] customer revenue requirement expected to be recouped through authorized forecasted sales to bundled customers.

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 bundled residential class and bundled residential class forecasted sales are used. Residential tariffs are then designed to collect the revenue requirement based on the forecasted sales reflected in the RAR.

BUNDLED AVERAGE RATES

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

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

Organization of the 2024 SB 695 Report

The remainder of this report is organized as follows:

[47] Bundled IOU customers receive all services — generation, transmission, and distribution services — from the IOU.

- **Chapter III**—A foundational review of *historical* trends in electric costs, rates, and bills with a focus on longer-term, capital-related costs and impacts on bills from wildfire safety, clean energy programs, and statutory mandates that have historically resulted in additional ratepayer costs.
- **Chapter IV**—A dive into special topics related to cost drivers.
- **Chapter V—**An evaluation of electric cost and rate *projections*. In addition, this chapter highlights affordability concerns in low to moderate income households.
- **Chapter VI**—Natural gas cost and rate trends.
- **Appendices—**Information provided by the IOUs to fulfill the requirements of Public Utilities Code Section 913.1(b) and reference material.

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

III. Historical Electric Cost, Rate, and Bill Trends

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

Revenue Requirement

Rate Component Trends

Simply put, the revenue requirement is what a utility has been authorized to collect from a customer in billing charges in order to provide safe and reliable service. Figure 1[48] presents combined authorized revenue requirement rate component trends for the electric IOUs at a system level.[49] Data is anchored to January 1 each year to maintain consistent year-over-year comparisons and is combined to provide a high-level comparison of the revenue requirement rate components and overall revenue requirement over time. More detailed analysis of select revenue requirements for each IOU is provided in the subsequent sections of this chapter.[50] The Assembly Bill (AB) 67 Reports[51] also provide detailed cost recovery data for each IOU using a floating effective date generally corresponding to each IOU's last rate implementation of the report year.

The figure below shows the combined total of all revenue requirements for PG&E, SCE, and SDG&E, classified by the type of rate component through which the revenue is collected.

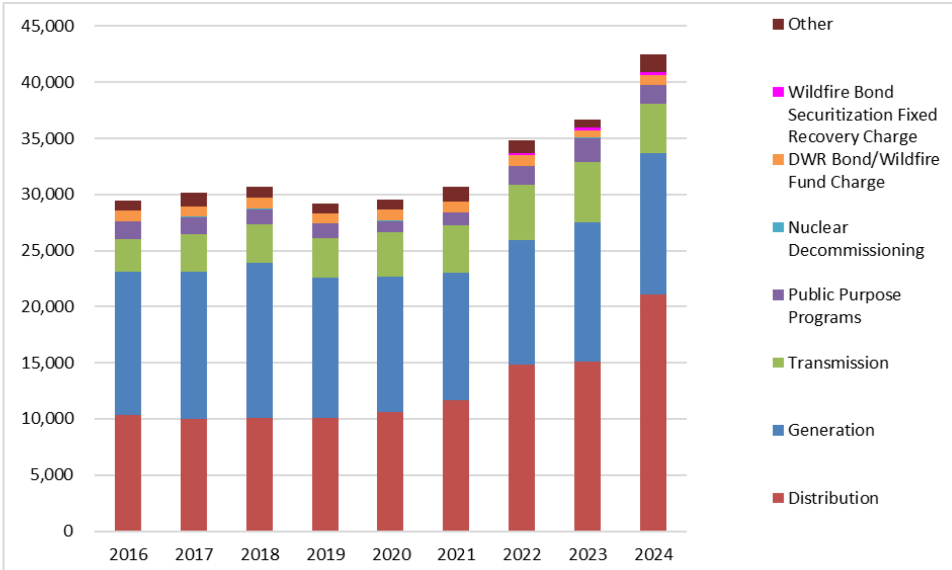
[48] Data time series starts in 2016 and is from IOU data responses to SB 695 Report data requests. Data in current report may be restated from previous reports.

[49] System-level includes all customer classes and all bundled and unbundled customers i.e., it is the total revenue requirement that the IOU collects. Generation includes Power Charge Indifference Adjustment (PCIA), a rate component intended to equalize cost sharing between departing load and bundled load. Distribution includes the netting effect of the semi-annual Greenhouse Gas Revenue Return credited to eligible customers through this rate component. Other may only apply to certain IOUs and not others and includes NSG, CTC, TRAC and ECRA rate components. Revenue requirement does not capture programs that result in a cross-subsidy between various customers groups such as the California Alternate Rates for Energy (CARE) surcharge between Non-CARE and CARE customers, which results in an additional amount to the PPP rate paid by Non-CARE customers. All dollars are nominal i.e., not adjusted for inflation unless otherwise indicated.

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

[51] *See* AB 67 Reports (Reports to the Legislature, linked by year) for more detail about factors driving electric revenue requirements for each IOU.

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



The distribution revenue requirement has significantly grown over time, with a substantial increase occurring between January 1, 2023 and January 1, 2024. This increase in distribution revenue requirement from January 1, 2023 to January 1, 2024 is mainly due to PG&E's distribution revenue requirement increasing by about 78 percent. By comparison, SCE's distribution revenue requirement over this time period increased by about 17 percent, and SDG&E's distribution revenue requirement decreased by about 1 percent.

Roughly three-quarters of this increase in PG&E's distribution revenue requirement is attributed to costs approved in PG&E's 2023 GRC.[52] These types of costs include power lines, poles, transformers, repair crews and emergency services, as well as certain wildfire mitigation costs related to grid reliability and safety, including liability insurance. The other approximately one-quarter of this increase is primarily due to wildfire mitigation and catastrophic event costs approved in several PG&E applications filed outside of the GRC proceeding process. Costs approved in these applications were related to costs incurred in the past several years.

Other revenue requirement components in the figure above have remained relatively stable between January 1, 2023, and January 1, 2024. The generation rate component reflects the recovery of "purchased power costs," or the costs of contracts with third-party electricity generators. It also reflects the cost of Utility Owned Generation (UOG), consisting of fuel and other operating expenses and capital costs associated with generation plants such as nuclear, gas, and hydroelectric.

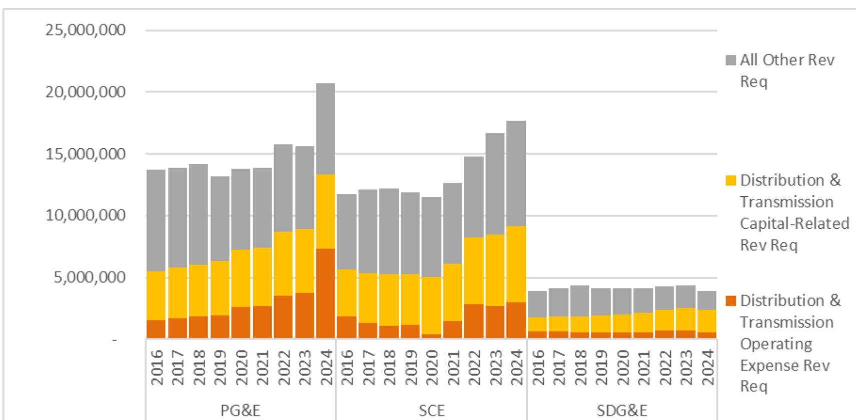
[52] *See* D.23-11-069. The late implementation of PG&E's 2023 GRC test year revenue requirement on January 1, 2024, is included in this increase. The test year is the first year in the new GRC cycle and if its implementation is delayed to a later year, the revenue requirement that would have been collected in the test year is included with the subsequent year's revenue requirement. Half of the delayed 2023 test year revenue requirement is to be collected in 2024.

The transmission rate component is set by the Federal Energy Regulatory Commission (FERC) and collects the revenue requirement associated with the utilities' assets determined to be part of the interstate transmission system. The Public Purpose Program rate component collects program funding authorized by the CPUC for Electric Program Investment Charge (EPIC), Energy Efficiency programs, Low-Income programs, and other public policy programs.[53]

Operating Expense and Capital-Related Cost Category Trends

Distribution and transmission operations and infrastructure investments are broad category cost drivers that continue to comprise a significant portion of IOU costs and rates.[54] Figure 2 shows the composition of these high-level cost drivers relative to total revenue requirement.[55] PG&E and SDG&E show an increasing combined distribution and transmission revenue requirement (orange plus yellow bars) relative to all other revenue requirements over time, from about 40 percent of the total revenue requirement in 2016 to approximately 65 percent in 2024. SCE combined distribution and transmission revenue requirements remain generally constant over this time period at approximately 50 percent of total revenue requirement.[56]

Figure 1: PG&E, SCE, and SDG&E Total Revenue Requirement with Breakouts for Combined Distribution and Transmission Operating Expense and Capital-Related Revenue Requirements (January 1, $000)



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[53] See the Electric Revenue Requirement section in the Background chapter for additional information.

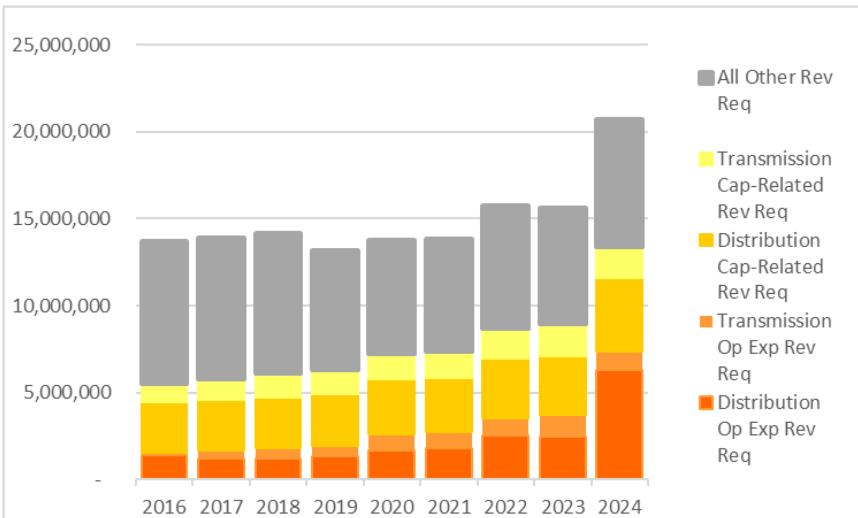
[54] While generation *operating expense* constitutes a large percentage of costs and rates, it is made up of primarily procurement costs that are pass-through expenses; the utility receives no mark up or profit on these costs. Generation *capital-related costs* result in revenue requirements of generally less than 2 percent of the total revenue requirements and are not further discussed in this report.

[55] Data time series starts in 2016 and is from IOU data responses to SB 695 Report data requests. Data in current report may be restated from previous reports.

[56] Comparative load growth over this time period shows an estimated decrease in electricity deliveries to all three IOUs. Retail load delivered data is from the California Energy Commission (CEC) 2023 Integrated Energy Policy Report (IEPR), California Energy Demand 2023-2040 Planning Forecast, Load Serving Entity (LSE) tables, 2016 – 2022 actual data, 2023 – 2024 forecasted data. Retail load delivered may be affected by weather among other factors.

The data represented in Figure 2 can be further sliced to separately show distribution and transmission operating expense and capital-related revenue requirements relative to total revenue requirement, as shown in Figures 3 - 5.[57] Orange areas representing operating expense revenue requirement in Figure 2 have been split to show a darker orange (distribution) and a lighter orange (transmission); yellow areas representing capital-related revenue requirement in Figure 2 have been split to show a darker yellow (distribution) and a lighter yellow (transmission).

Figure 2: PG&E Total Revenue Requirement with Breakouts for Distribution and Transmission Operating Expense and Capital-Related Revenue Requirements (January 1, $000)



[57] Revenue requirements that are not capital-related are classified as operating expenses. Revenue requirements that do not appear in the graphs, e.g., SCE and SDG&E 2024 transmission operating expense, have negative amounts due to swings from under- to over-collected balances.

Figure 3: SCE Total Revenue Requirement with Breakouts for Distribution and Transmission Operating Expense and Capital-Related Revenue Requirements (January 1, $000)

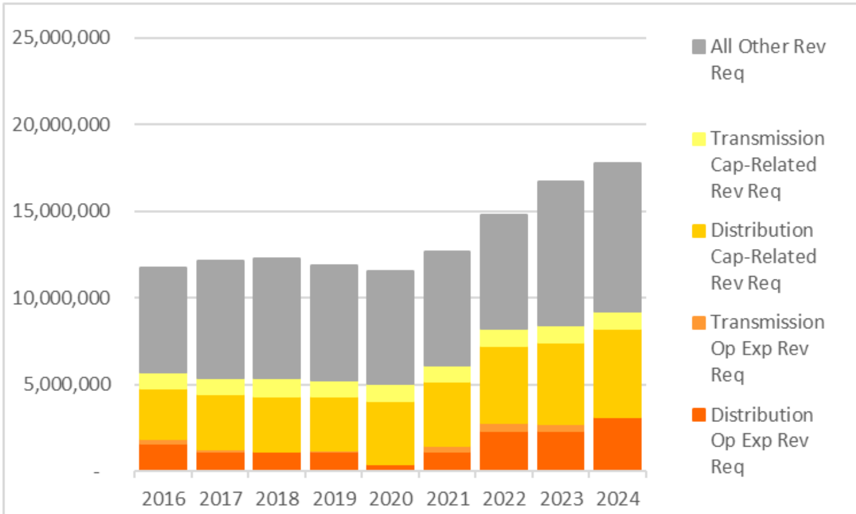
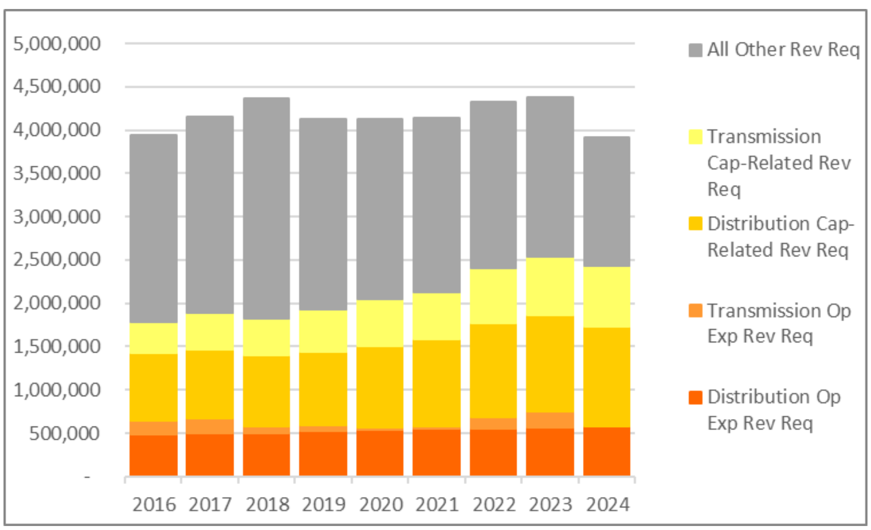


Figure 4: SDG&E Total Revenue Requirement with Breakouts for Distribution and Transmission Operating Expense and Capital-Related Revenue Requirements (January 1, $000)



Figures 3 - 5 show that from 2021 (the year from which system rate increases grew substantially faster than over previous years' system rate increases) to 2024, for **operating expense revenue requirement**:

- **PG&E[58] and SCE's distribution operating expense amounts (dark orange) have grown at a significantly faster rate than other utility revenue requirements, increasing from about 13 percent to 30 percent and from about 9 percent to 18 percent of the total revenue requirement, respectively. This increase is driven primarily by wildfire-related revenue requirement**; see Chapter IV section "Historical Wildfire-Related Costs" for more information. SDG&E's distribution operating expense (dark orange) as a percentage of the total revenue requirement has remained relatively constant at about 14 percent.
- Transmission operating expense (light orange) as a percentage of the total revenue requirement for all IOUs has remained relatively constant as a fairly small portion of the total revenue requirement at about 6 percent for PG&E, 2 percent for SCE, and 0.5 percent for SDG&E.

With respect to **capital-related revenue requirement**, Figures 3 – 5 show that from 2021 (the year from which system rate increases grew substantially faster than over previous years) to 2024:

- PG&E and SCE's distribution capital-related amounts (dark yellow) as a percentage of total revenue requirement have remained relatively constant at about 22 percent and 29 percent, respectively. SDG&E's distribution capital-related amount (dark yellow) as a percentage of total revenue requirement has increased from about 24 percent to 30 percent.
- PG&E and SCE's transmission capital-related amounts (light yellow) as a percentage of total revenue requirement for each IOU have remained relatively constant at about 10 percent and 7 percent, respectively. SDG&E's transmission capital-related amounts (light yellow) as a percentage of total revenue requirement has increased from about 13 percent to 18 percent. **Transmission capital-related amounts (light yellow), while currently a relatively low percentage of total revenue requirement at 8 percent and 7 percent for PG&E and SCE, respectively, are projected to grow to reflect significant capital expenditures[59] that are expected to mount in revenue requirement[60] due to transmission expansion driven by clean energy goals.** See Chapter IV Section "Other Topics of Interest" for more information.

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[58] The large increase in PG&E's 2024 distribution operating expense (dark orange bar in Figure 3) substantially reflects PG&E's 2023 General Rate Case (GRC) implementation in 2024. The decision in that GRC cited the following drivers for the approved increased costs: mitigating the risk of catastrophic wildfire, improving reliability, and preparing the grid for increases in customer load growth and new connections.

[59] Capital expenditures do not affect revenue requirement until a project is operative at which time capital expenditures become capital additions to rate base.

[60] Capital-related revenue requirement has a larger cumulative impact on rates relative to operating expenses in the long run on a dollar-for-dollar basis as it is recovered over a much longer time horizon during which the IOUs also earn an authorized rate of return on rate base. *See* Figure 22 for a comparison of the timing of recovery of $1 billion as an operating expense revenue requirement versus a capital-related revenue requirement.

Rate Base

Rate base grows as new authorized capital expenditures are brought into service and layered over existing capital expenditures.[61] Increases in rate base have a direct relationship with increases in the capital-related revenue requirement as a result of the new capital expenditures' depreciation expense and return on rate base revenue requirements. If new customers or increased electricity usage does not occur, the increased rate base leads to higher rates and a corresponding increase in customer bills. The direct relationship between expanding rate base and capital-related revenue requirements has a compounding impact on overall revenue requirement in rates.

Figures 6 - 8 show combined distribution and transmission rate base and retail load delivered by each IOU over the 2016 – 2024 period.[62] Combined distribution and transmission rate base has been increasing on an average annual percent change basis of approximately 11 percent for PG&E and SCE, and 8 percent for SDG&E.[63] **Distribution and transmission rate base growth shows an inverse relationship with volume of load served, with rate base continuing to increase since 2016 while total energy delivered has been declining overall since 2016.** Consequently, until rate base growth is matched or outpaced by kWh sales, bundled rates will continue to climb.

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[61] If no new capital expenditures were added, rate base would decline as the underlying investment depreciates over its useful life.

[62] Rate base time series starts in 2016 and is from IOU data responses to SB 695 Report data requests. Data in current report may be restated from previous reports. Rate base shown for net plant/capital additions only, i.e., "other" non-plant/capital additions rate base is not included. Retail load delivered data is from the California Energy Commission (CEC) 2023 Integrated Energy Policy Report (IEPR), California Energy Demand 2023-2040 Planning Forecast, Load Serving Entity (LSE) tables, 2016 – 2022 actual data, 2023 – 2024 forecasted data. Retail load delivered may be affected by weather and customer generation, among other factors.

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

Figure 5: PG&E Distribution and Transmission Rate Base (January 1, $000) and Retail Energy Delivered (GWh)

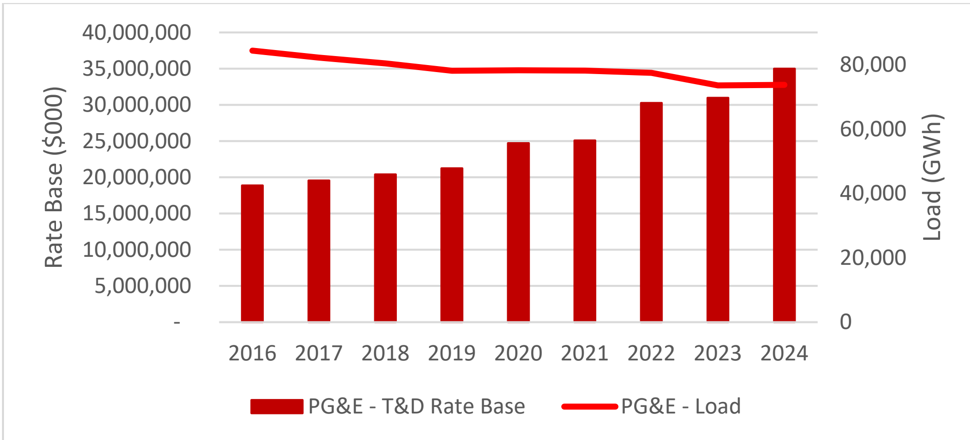


Figure 6: SCE Distribution and Transmission Rate Base (January 1, $000) and Retail Energy Delivered (GWh)

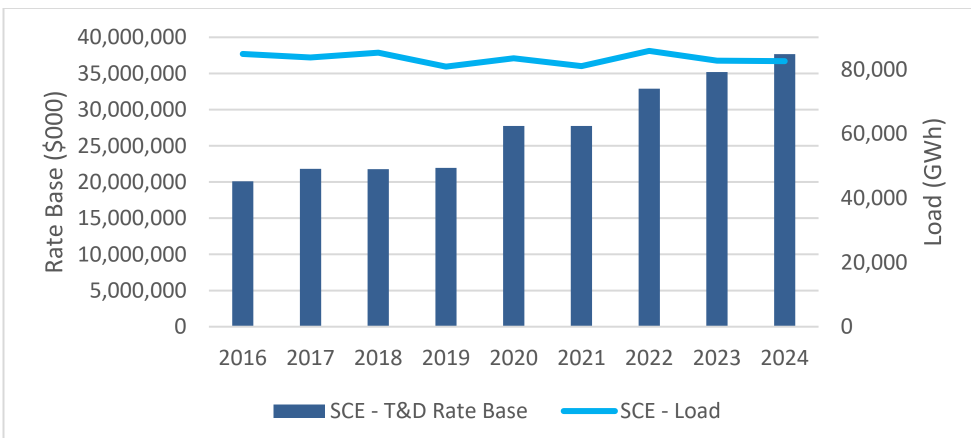
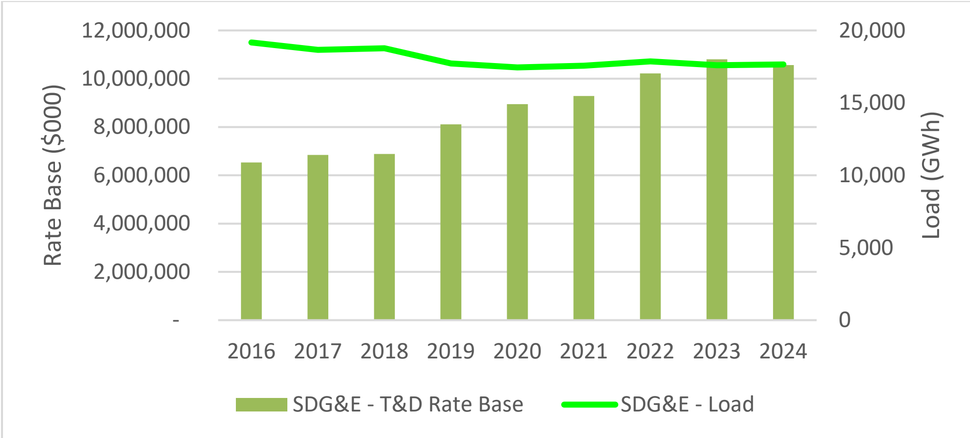


Figure 7: SDG&E Distribution and Transmission Rate Base (January 1, $000) and Retail Energy Delivered (GWh)



Rates and Bills

Bundled System Average Rate

Historical rate trends allow comparison of how an IOU's rates track inflation over time. The reason inflation is typically used as a benchmark for electric rate growth is because it has traditionally been assumed that household incomes rise at about the rate of inflation, thus if electric rates increase at the same rate, then the affordability of electric service should remain unchanged for the average household. However, it should be noted that while inflation generally affects the costs underlying the utility's revenue requirement, rates and bills are impacted by other factors, such as wholesale natural gas prices, inflation, high interest rates, and supply chain challenges which have prevented rates from tracking inflation.

California energy utility customers continue to face financial pressure from rate increases. Starting in 2021, bundled system rate[64] increases began to outpace inflation for all three large electric IOUs as shown in Figure 9.[65] The downward trend in SDG&E's bundled system average rate between 2023 and 2024 is expected to reverse later in 2024 when rates resulting from its 2024 GRC go into effect.

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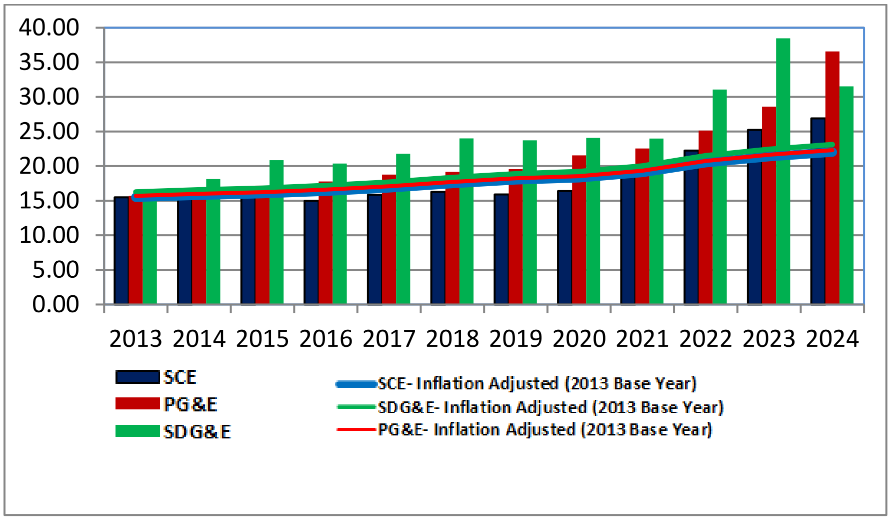
[64] Bundled system average rate: Bundled IOU customers receive all services — generation, transmission, and distribution services — from the IOU; System-level includes all customer classes.

[65] Prior to 2021, when looking at rates back to 2013, one IOU's rate growth tracked inflation (SCE) and two IOU's rate growth did not (PG&E and SDG&E). Prior to 2013, all IOU rates generally tracked inflation.

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



Bundled System Average Rate by Customer Class

A breakdown of the bundled system average rate by customer class e.g., bundled residential average rate, bundled small commercial average rate, etc. is shown for each IOU in Figures 10 - 12.[66] Each class rate shows the same upward trend as the system average rate over this period, with residential, small commercial, and medium commercial customers generally having higher average rates than the system average, and the large industrial and agricultural customers having lower average rates, with the exception of PG&E agricultural customers who have higher average rates than system starting in 2019.[67]

[66] Data time series starts in 2016 and is from IOU data responses to SB 695 Report data requests. Data in current report may be restated from previous reports. Includes California GHG Allowance Return which functions as a revenue requirement reduction. PG&E customer class rate schedules Res = Non-CARE and CARE; Small (e.g., B-1); Medium = B-10 & E-19; Large, also known as Industrial = E-20; Ag = AG; SCE customer class rate schedules Res = Non-CARE and CARE; Small = TOU-GS-1; Medium = TOU-GS-2 & TOU-GS-3; Large, also known as Industrial = TOU-8-S/P/T & TOU-8-S-S/P/T; Ag = TOU-PA-2 & TOU-PA-3; SDG&E customer class rate schedules are not associated with any specific rate schedule. SDG&E has a combined medium/large commercial & industrial customer class.

[67] 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 9: PG&E Bundled System Average Rate By Class, Nominal Rates in Effect January 1 (¢/kWh)

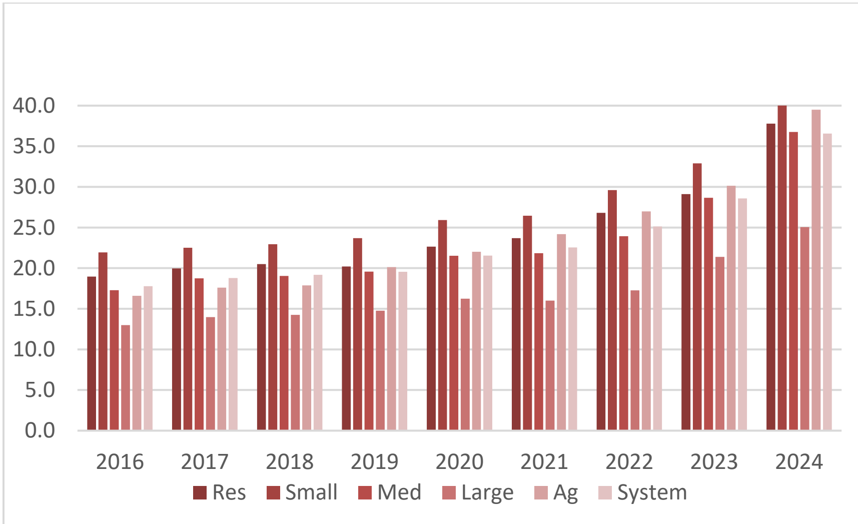


Figure 10: SCE Bundled System Average Rate By Class, Nominal Rates in Effect January 1 (¢/kWh)

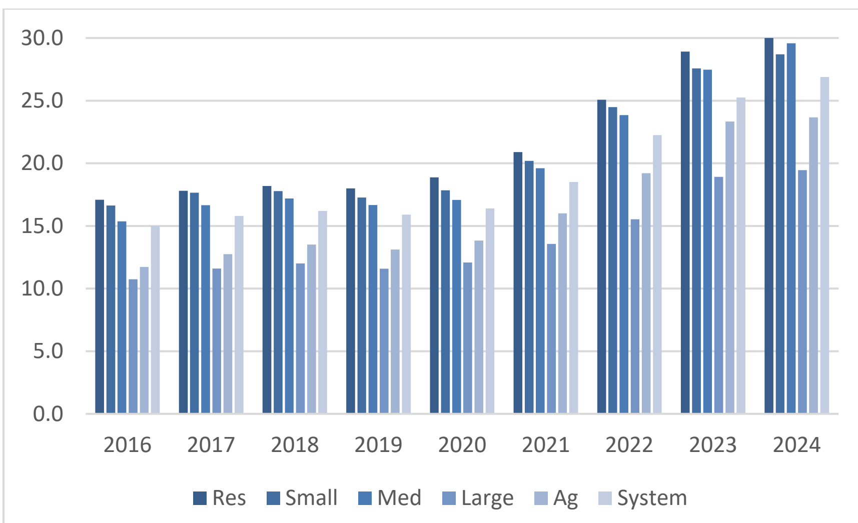
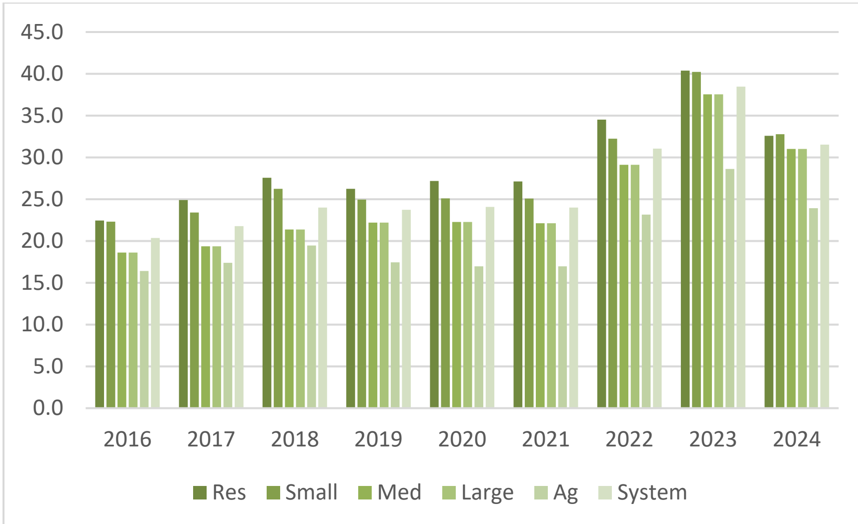


Figure 11: SDG&E Bundled System Average Rate By Class, Nominal Rates in Effect January 1 (¢/kWh)



Bundled Residential Average Rate

California's electric utility rates and bills are trending higher in national comparisons. Historically, the bundled Residential Average Rates (RAR) of the California IOUs have been higher than those of most United States IOUs.[68] Despite the fact that average residential electricity usage in California is low compared to IOUs nationally, bundled residential average monthly bills started to increase in 2020.

Table 1 shows ranking data based on U.S. Energy Information Administration (U.S. EIA) bundled RAR for PG&E, SCE, and SDG&E from 2019 to 2022.[69] This data ranks approximately 200 total IOUs nationally from highest rates (#1 ranking) to lowest rates (#200 ranking). For example, in 2022, SDG&E's bundled RAR ranked 5th highest but on an average bill basis ranked 43rd.[70] Rate data for all U.S. IOUs is on a simple volumetric basis of revenues divided by sales without regard to rate design.

While rates reflect the cost of providing each kilowatt hour of electricity, bill data provides a clearer picture of customer financial impact. From 2019 to 2022, California IOU bundled residential customer bills have been quickly trending upward relative to the bills of approximately 200 total IOUs nationally. For example, in 2019, PG&E's bundled residential average monthly bill ranked 70th highest out of about 200 IOUs, but in 2022, PG&E's bundled residential average monthly bill

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68 *See* U.S. Energy Information Administration (U.S. EIA) data in Table 2.

69 *See* https://www.eia.gov/electricity/sales_revenue_price/, Table 6; 2022 is the most recent year for which national-level annual data is available.

70 IOUs located in Hawaii and New York (Fishers Island) were in the first to fourth positions.

ranked 18th highest. SCE and SDG&E's bundled residential average monthly bills show similar bill ranking trends since 2019, as shown in Table 1.

Table 1: U.S. IOU Ranking of PG&E, SCE, and SDG&E (Out of Approximately 200 IOUs) Bundled Residential Average Rates and Monthly Bills (U.S. EIA)

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

Table 2 shows the corresponding U.S. EIA rate and monthly bill amounts for the large California IOUs.[71]

Table 2: PG&E, SCE, SDG&E Bundled Residential Average Rate and Monthly Bill (U.S. EIA)

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

RAR in Recent Years

Since 2013,[72] bundled residential average rates have increased at an average annual rate greater than the assumed rate of inflation: about 12 percent for PG&E, and 7 percent for SCE and SDG&E.[73]

Figures 13 - 15 show each IOU's nominal and inflation-adjusted bundled RAR for the period 2013 to 2024 (left side) and each IOU's bundled residential revenue requirement and forecasted sales for

[71] Bill amounts are hypothetical at class level without distinction between customers who receive a low-income program bill discount and those who do not. U.S. EIA data for 2022 shows average monthly usage figures: PG&E 546 kWh; SCE 562 kWh; SDG&E 392 kWh.

[72] Prior to 2013, the total system average rate (i.e., all rate classes) of each of the IOUs roughly tracked inflation; *See* the 2023 Assembly Bill (AB) 67 Report.

[73] Inflation rate 2013 base year to 2024 is 3.0 percent/year, based on Consumer Price Index (CPI), California Region, All Items, All Urban Consumers, reported by the California Department of Finance (DOF), available here (CPI Forecast Data published November 2023). Utility rate increases calculated from January 1, 2013 to January 1, 2024. Average annual percent changes to utility rates throughout this report are based on a simple, smoothing calculation of: (end of period value – beginning of period value)/number of periods where 'periods' is defined as a range of years. SDG&E average annual rate increase is artificially low due to the low rate on January 1, 2024 that is expected to reverse later in 2024 when rates from its 2024 GRC go into effect.

the period 2016 – 2024 (right side).[74] Side-by-side presentation facilitates comparing how RAR is impacted by changes in constituent revenue requirement and forecasted sales. In the graphs on the left, nominal rates trending below the black line (i.e., inflation-adjusted rates) indicate that the IOU's bundled RARs are tracking favorably to inflation-adjusted rates. Nominal rates trending above the black line indicate that the IOUs' bundled RARs are increasing at a rate higher than the rate of inflation. In the graphs on the right, certain bundled residential data is considered confidential by SCE and SDG&E and has been labeled as such where applicable. Table 3 summarizes the effects of revenue requirement and forecasted sales on rates such as bundled RAR.

Table 3: Combined Effects of Revenue Requirement and Forecasted Sales on Rates

Combination	Effect on Rates
Revenue Requirement ↓ **Forecasted Sales ↑**	↓
Revenue Requirement ↑ **Forecasted Sales ↑**	Depends which effect is stronger; If revenue growth % stronger than sales growth %: ↑ If sales growth % stronger than revenue growth %: ↓
Revenue Requirement ↓ **Forecasted Sales ↓**	Depends which effect is stronger; If revenue decline % stronger than sales decline %: ↓ If sales decline % stronger than revenue decline %: ↑
Revenue Requirement ↑ **Forecasted Sales ↓**	↑

In Figure 13, the graph on the left shows PG&E's nominal bundled RAR growing at an increasing rate in the year 2020, rapidly outpacing inflation. In the graph on the right, the bundled residential revenue requirement shows a declining trend since 2016. PG&E states that it had significant bundled load departure to Community Choice Aggregators (CCA) from 2016[75] to 2022 which may account in part for this decline.[76] A generally commensurate decrease in bundled residential forecasted sales is also partly due to bundled load departure to CCAs. From Table 3, the increase in bundled residential average rates since 2013---accelerating in 2020--- means that on a percentage

[74] Data time series starts in 2016 and is from IOU data responses to SB 695 Report data requests. Data in current report may be restated from previous reports. Includes the California Climate Credit (CCC) which functions as a revenue requirement reduction.

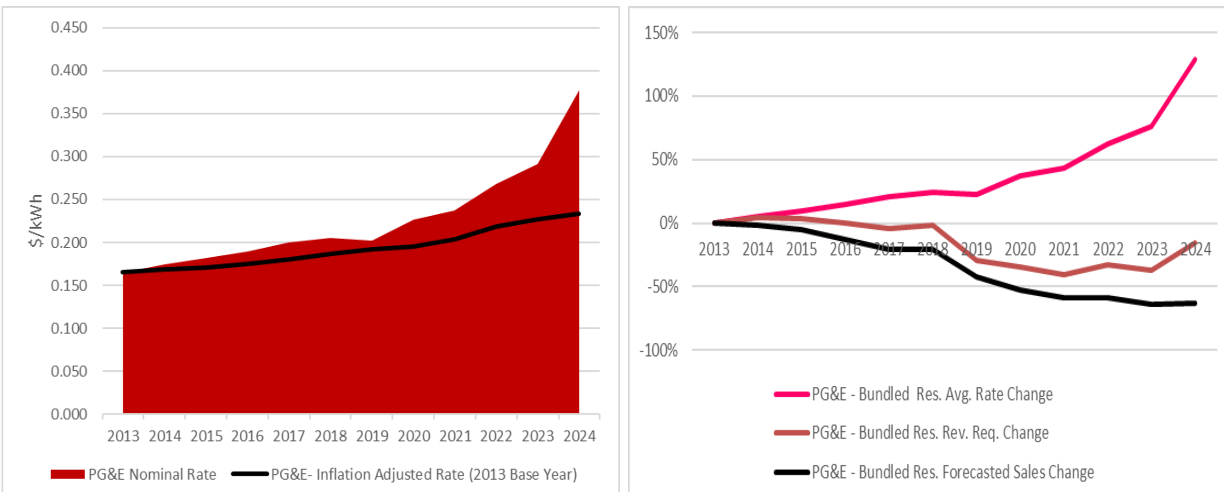
[75] CCAs in PG&E's service territory were in existence starting in 2010.

[76] A CCA provides generation service to an unbundled IOU customer. When a previously bundled residential customer switches to a CCA, the IOU bundled generation revenue requirement decreases to reflect that the IOU is no longer procuring energy for the unbundled customer. The IOU bundled generation forecasted sales also decreases. This commensurate decrease in forecasted sales has a "wash" effect, meaning the revenue requirement and forecasted sales effects cancel each other out for a zero net effect on rates.

basis, the effect of the decline in forecasted sales is greater than the effect of decline[77] or growth[78] of the revenue requirement, resulting in an increase in rates.

A factor for this decline in forecasted sales is the increase in behind-the-meter generation---utility fixed costs are now spread across fewer units of usage.[79] Of the three large IOUs, PG&E has the second largest share of bundled residential customers on NEM tariffs at 23 percent.[80] As a result of declining sales and other factors, Non-CARE and CARE customer bills for customers not participating in NEM are about 14 percent higher than they would have been without NEM tariffs.[81]

Figure 12: PG&E January 1 Nominal and Inflation-Adjusted Bundled Residential Average Rate (Left Side)
and January 1 Growth in Bundled Residential Rates, Bundled Authorized Revenue Requirement and Forecasted Sales, Pegged to 2013 (Right Side)



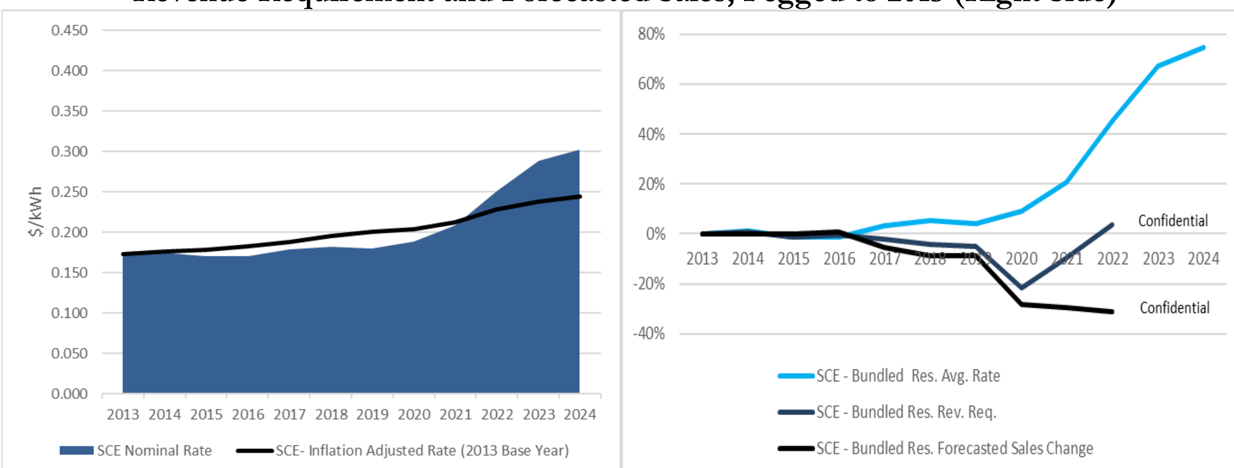
In Figure 14, the graph on the left shows SCE's nominal bundled RAR starting to generally increase at an increasing rate in the year 2021 and how remarkably coincident its bundled RAR is relative to inflation up until that time. Figure 14 on the right may reflect bundled load departure to CCAs in SCE's service territory, starting in about 2016,[82] with changes in bundled residential revenue requirement and decreases in forecasted sales both mildly divergent from the increase in bundled residential average rates through 2019.[83] Starting in 2021, rapidly rising rates indicates that on a

[77] *See* third row of Table 3: If sales decline % is stronger than revenue decline %, then rates go up.
[78] *See* fourth row of Table 3: If sales and revenue requirement go down, then rates go up.
[79] The NEM cost shift due to overcompensation of exported energy effectively moves with the unbundled customer to the CCA, while the NEM cost shift due to avoidance of fixed costs remains with the IOU. *See* Chapter IV section, "Net Energy Metering and Net Billing Tariffs Cost Shifts."
[80] SDG&E has the largest share of bundled residential customers on NEM tariffs at 26 percent. *See* Table 4.
[81] *See* Table 5.
[82] CCAs in SCE service territory started after those in PG&E's service territory, with the establishment of the first CCA in 2015.
[83] CCAs in SCE service territory started after those in PG&E's service territory, with the establishment of the first CCA in 2015.

percentage basis, the effect of the decline in forecasted sales exceeds the decline or growth in revenue requirement, a factor for which is the NEM program. Data needed to further deconstruct bundled RAR beyond 2022 is not currently available due to SCE's confidentiality labeling.[84]

SCE has about 15 percent of bundled residential customers on NEM tariffs.[85] As a result of declining sales and other factors, under current NEM tariffs, Non-CARE and CARE customer bills for customers not participating in NEM are about 11 percent higher than they would have been without current NEM tariffs.[86]

Figure 13: SCE January 1 Nominal and Inflation-Adjusted Bundled Residential Average Rate (Left Side) and January 1 Growth in Bundled Residential Rates, Bundled Authorized Revenue Requirement and Forecasted Sales, Pegged to 2013 (Right Side)



In Figure 15, the graph on the left shows SDG&E's bundled RAR sharply increasing in 2022 as well as how its bundled RAR has historically not maintained a close correlation with inflation. Figure 15 on the right may reflect bundled load departure to CCAs in SDG&E's service territory, starting in about 2018,[87] with decreases in forecasted sales being fairly divergent from the increase in bundled residential average rates starting in 2013--- indicating the effects of the NEM program prior to the 2013 start date of this graph. Data needed to further deconstruct bundled RAR beyond 2022 is not currently available due to SDG&E's confidentiality labeling.[88]

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[84] 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."

[85] *See* Table 4.

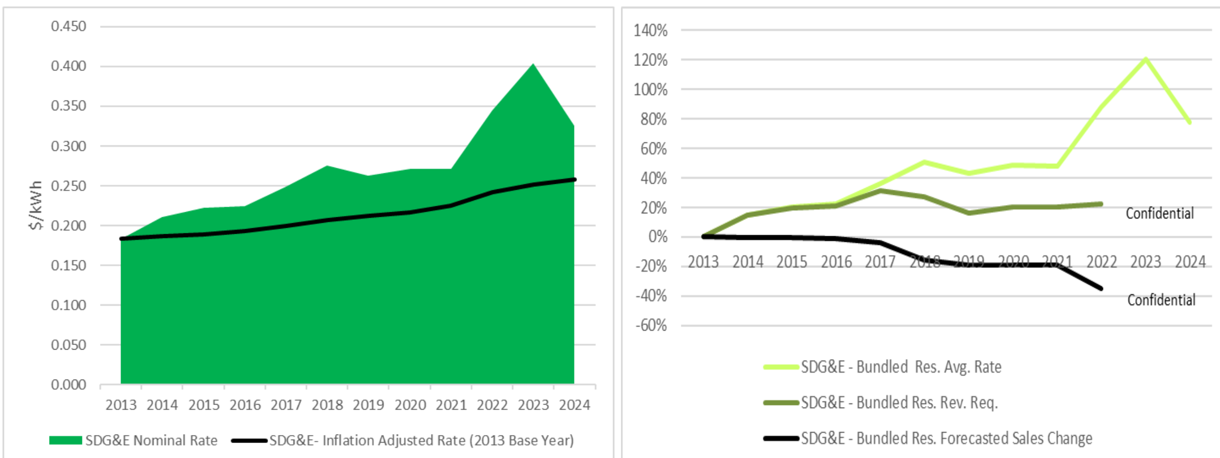
[86] *See* Table 5.

[87] The first CCA in SDG&E's service territory began service in 2018.

[88] SDG&E claims confidentiality under section V.C. of the IOU Confidentiality Matrix, adopted as Appendix 1 of CPUC Decision D.06-06-066. For more information about the confidentiality of certain SDG&E bundled customer information, *see* 2021 SB 695 Report , Chapter III, section "Bundled Rate Transparency Considerations."

SDG&E, at 26 percent, has a larger share of customers investing in rooftop solar compared to PG&E and SCE.[89] As a result of declining sales and other factors, Non-CARE and CARE customer bills for customers not participating in NEM range from about 20 percent to 25 percent higher than they would have been without current NEM tariffs.[90]

Figure 14: SDG&E January 1 Nominal and Inflation-Adjusted Bundled Residential Average Rate (Left Side) and January 1 Growth in Bundled Residential Rates, Bundled Authorized Revenue Requirement and Forecasted Sales, Pegged to 2013 (Right Side)



Bundled Residential and Select Small Commercial Average Monthly Bills

The major determinant in calculating bills is electricity usage.[91] Residential usage tends to cluster around typical usage profiles, which vary by climate zone.[92] However, typical load profiles for non-residential customers can vary substantially, depending on their usage patterns (or load profiles) in the commercial, industrial, or agricultural customer class.[93] Nevertheless, small commercial customers may be grouped by commercial customer group using standards such as the North American Industry Classification System (NAICS) to get a sense of typical usage characteristics for customers with the same industry code.[94]

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[89] *See* Table 4.

[90] *See* Table 5.

[91] 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.

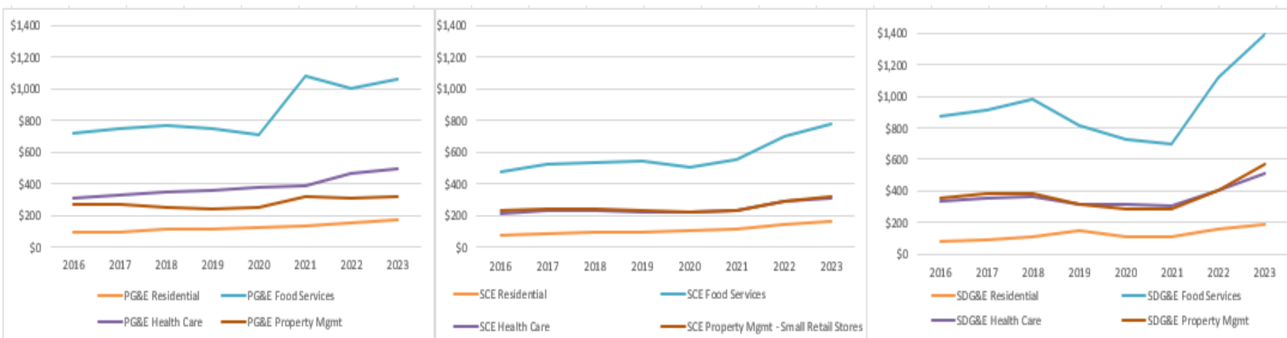
[92] Climate zones are drawn in each IOU's service territory based on climactic variation and are also known as baseline territories as defined by each IOU in its Preliminary Statements.

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

[94] 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.

Figure 16[95] shows for each IOU typical bundled average monthly bills for residential customers[96] as well as for small commercial customers representing Food Services and Drinking Places (NAICS 722), Ambulatory Health Care Services (NAICS 621), and Real Estate (Property Management, NAICS 531).[97] Bundled small commercial customers with industry subsector Food Services (NAICS 722) show recent typical average monthly bills in the $800 to $1,400 range, with industry subsector Health Care Services (NAICS 621) and Property Management (NAICS 531) showing bills in the range of $300 to $500.

Figure 15: PG&E, SCE, and SDG&E January 1 Typical Bundled Average Monthly Bills, Residential and Select Small Commercial



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[95] Data time series starts in 2016 and is from IOU data responses to SB 695 Report data requests. Data in current report may be restated from previous reports.

[96] Residential customers not enrolled in the California Alternate Rates for Energy (CARE) program. Lower-income residential customers enrolled in the CARE program receive up to a 35 percent discount on bills. Typical Non-CARE customer using 500 kWh (PG&E climate zone X, SCE climate zone 9, and 400 kWh (SDG&E Inland climate zone). PG&E residential bills include the California Climate Credit (CCC). More information is available at: CPUC Rate Change Advisories.

[97] *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.

IV. SPECIAL TOPICS

As in the reports from the last several years, this year's report continues its closer look at cost impacts of Net Energy Metering and Net Billing tariffs as well as trends in wildfire-related costs and transportation electrification-related[98] costs embedded in distribution and transmission revenue requirements.

Net Energy Metering and Net Billing Tariffs Cost Impacts

Net energy metering (NEM) tariffs and net billing tariffs[99] (NBT) are available to IOU customers with behind-the-meter renewable electrical generation facilities, such as rooftop solar photovoltaic (PV) systems, with or without energy storage systems. Since implementing NEM over 25 years ago, California has witnessed the rapid growth of the customer-sited rooftop solar industry, resulting in the installation of over 14.8 gigawatts of clean distributed energy resources.[100]

Legislative and Regulatory Background

California's NEM tariffs started in 1997, directed by SB 656 (Alquist, 1995). The tariffs allow customers who install eligible renewable electrical generation facilities to serve onsite energy needs and receive credits on their electric bills for surplus energy sent to the electric grid. Almost all customer-sited, grid-connected solar PV in California is interconnected through NEM/NBT tariffs.

The first NEM design, now known colloquially as "NEM 1.0," was revised in 2016 per AB 327 (Perea, 2013) when the CPUC adopted the NEM successor tariff now referred to as "NEM 2.0."[101] The CPUC was required by statute to ensure that the NEM successor tariff is based on the costs and benefits of the distributed generation systems, that it achieves various equity-related aims, and that customer-sited renewable distributed generation continues to grow sustainably.[102] Customers on NEM 2.0 pay for their cost to connect to the grid, take service on a time-of-use (TOU) rate plan,[103] and pay certain non-bypassable charges[104] that cannot be offset with energy export credits, in order to contribute a portion of their fair share of the costs of public purpose programs and other initiatives.

In 2022, the CPUC adopted a successor NBT design that balances multiple statutory requirements and the needs of the electric grid, the environment, NEM participants, and all other ratepayers.[105]

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[98] Building electrification costs are not presented as these costs are still at a nascent stage.
[99] Includes subtariffs.
[100] As of December 31, 2023. *See* California Distributed Generation Statistics.
[101] *See* D.16-01-044.
[102] *See* Public Utilities Code §2827.1(b)(1), §2827.1(b)(3), and §2827.1(b)(4).
[103] TOU rate plan energy prices are based on when and how much energy is used. TOU rates are lower during the day, e.g., before 4 or 5 p.m., when less expensive renewable energy sources like solar and wind are available.
[104] D.16-01-044 lists the non-bypassable charges as: Public Purpose Program Charge; Nuclear Decommissioning Charge; Competition Transition Charge; and Department of Water Resources bond charges. Other non-bypassable charges may be statutorily required.
[105] *See* D.22-12-056.

The NBT seeks to reduce greenhouse gas emissions and increase grid reliability by aligning tariff price signals with the electric grid's conditions, i.e., incenting customer energy imports from the grid when there is plentiful, clean, low-cost grid energy, and incenting customer energy exports when grid supply is tight and most polluting. These price signals encourage the adoption of combined solar and storage systems. The new tariff also implements higher incentives for customers in low-income households than for other customers.

Notably, the CPUC did not reform the existing tariffs, meaning that NEM 1.0 and NEM 2.0 customers may retain these tariffs' full benefits for the remainder of the customers' individual 20-year legacy periods. For example, the last customers to enroll in NEM 1.0 in 2017 will receive that tariff's benefits through 2037, and the last to enroll in NEM 2.0 in 2023 will do so through 2043. If a property with a NEM system changes hands, the system's legacy period remains in effect.

Table 4 shows the number of bundled residential customers and total customers (bundled and unbundled)[106] on NEM 1.0/NEM 2.0 tariffs and NBT at year-end 2023.[107] PG&E and SDG&E bundled residential customers on a NEM tariff or NBT represent about one quarter of those IOUs' bundled residential customers.

Table 4: PG&E, SCE, and SDG&E Residential NEM and NBT Customer Counts, Year-End 2023 (rounded to the nearest thousandth)

	Bundled Residential			Total Residential (Bundled + Unbundled)		
	Number Customers on NEM Tariff/NBT	Number of Customers	Percentage of Customers on NEM Tariff/NBT	Number of Customers on NEM Tariff/NBT	Number of Customers	Percentage of Customers on NEM Tariff/NBT
PG&E	416,000	1,818,000	23%	808,000	4,962,000	16%
SCE	489,000	3,194,000	15%	625,000	4,576,000	14%
SDG&E	100,000	380,000	26%	304,000	1,356,000	22%

NEM program costs are also one of the largest contributors to rising electricity rates for customers that do not have rooftop solar. As of year-end 2023, for a typical PG&E customer without rooftop solar, NEM program costs account for 14 percent of their electricity bill. For a typical SCE customer without rooftop solar, NEM costs account for 11 percent of their electricity bill. For a typical SDG&E customer without rooftop solar, NEM costs account for up to 25 percent of their

[106] Unbundled customers take from the IOU distribution and transmission service only, with generation service provided by a separate entity, usually a Community Choice Aggregator (CCA) or Direct Access (DA) service provider. Figures are combined Non-CARE and CARE residential customers.
[107] PG&E as of November 30, 2023; SCE and SDG&E as of December 31, 2023.

electricity bill.[108] Figure 17 illustrates the portion of the typical customer bill that is due to NEM program costs.[109]

Figure 16: NEM Cost Portion of a Typical Residential Customer Monthly Bill (2023)

The NEM 1.0 and NEM 2.0 program increase electricity bills in two ways: (1) customers pay for the generation that is exported to the grid from another customer's NEM system at a higher rate than other available generation, and (2) customers pay for the part of bill savings experienced by NEM customers because the program allows rooftop customers to bypass their share of fixed costs to maintain the electric grid, which other customers without rooftop solar end up paying.

IOU customers without rooftop solar are paying NEM customers for the generation they send to the electric grid at a rate that exceeds the cost of generation otherwise available from the grid. NEM 1.0 and NEM 2.0 customers are compensated for electricity exported to the grid at the retail volumetric rate, which exceeds the marginal cost of avoided wholesale generation purchased for that customer. IOU customers pay this increased cost to NEM customers for 20 years after their grid interconnection dates.

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

[109] For PG&E, the customer bill data reflects the bill of a typical bundled customer using 500 kWh/month, which is closer to the non-NEM average usage than an all customer average usage, as much of NEM participants' bills are offset by the systems themselves. For SCE, the customer bill data reflects an average across all bundled customers, but the 500 kWh/month typical customer usage used for the calculations is closer to a non-NEM average usage than an all customer average usage, as much of NEM participants' bills are offset by the systems themselves. SDG&E's data is not averaged across all bundled customers, but rather assumes a 400 kWh/month, non-NEM customer.

The reduction in grid consumption results in a bill savings for NEM customers but increases bills for other customers. This occurs because in California, the fixed costs of electricity services (including support for low-income customers) are primarily collected through the volumetric distribution rate component of customer bills. Customers who use less electricity pay a smaller share of these fixed costs, even though the total fixed costs are not reduced when customers reduce the volume of energy consumed. As a result, when customers reduce their bills by substituting rooftop solar production for grid generation, they are reducing their share of fixed volumetric costs and that share is paid by other customers. The fixed costs are spread across fewer units of usage and customers without NEM systems see their bills increase.

Distributed energy resources are an important part of California's overall electricity supply, and new policies are helping to send improved price signals to these resources so that they can best support the electric grid needs of today. From April 2023 on, new rooftop solar customers—or prior NEM customers at the end of their 20-year legacy interconnection periods—will receive compensation through the new NBT, which provides compensation that is more aligned with the value of the generation the systems provide to the grid and includes more favorable price signals for systems with battery storage compared to rooftop solar. This cost increase, however, is not fully mitigated by the new NBT.

The record in the NBT proceeding showed that monthly bill savings is a major factor in customers deciding to install a solar system, and the NBT decision determined that a nine-year simple payback period for a stand-alone solar system[110] — equivalent to nearly $100 in monthly bill savings — partially reduces the cost borne by customers without solar.

It is estimated that the NEM 1.0 and NEM 2.0 cost shift[111] will cost customers[112] approximately $6.5 billion in 2024, a near-doubling of this amount since 2021.[113] The recent program cost increases are driven by two main factors: (1) a surge in customers installing rooftop solar prior to the phase out of the NEM program, and (2) higher compensation to NEM customers for the excess energy their systems generate since 2021 due to IOU rate increases. When NEM customers directly power their electricity load with energy from their rooftop solar system, they avoid paying for electricity drawn from the grid at the electricity rate other customers are paying. When IOUs increase rates through

[110] Simple payback period equals the cost of the system divided by first-year bill savings. This increased payback period under the NBT is generally a function of reduced NEM export compensation rates. The decision provides a glide path with a higher adder to ensure eligible low-income customers achieve the same nine-year payback target for stand-alone solar systems that all other residential customers receive. NBT customers with a solar system paired with storage will likely have a shorter payback period and may see greater monthly bill savings than participating customers with a stand-alone solar system.

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

[112] All PG&E, SCE, and SDG&E customers, i.e., bundled and unbundled across all customer classes. Figures also include NEM customers, although most of this cost burden is shifted to non-NEM customers, since much of NEM customers' bills are offset by the NEM systems.

[113] *See* the Public Advocates Office's Memo dated February 8, 2024 (updated February 28, 2024).

General Rate Cases, NEM customers benefit financially by avoiding these increased rates that are recovering the full set of costs to serve all customers connected to the grid.

Figures 18 - 20 show the estimated historical NEM cost shifts calculated by each IOU for residential customers.[114] Although the NBT existed in 2023, the cost shift attributable to it is substantially smaller and is not included here.[115] New to the report this year is the representation of this data by the approximate generation-related and delivery-related elements of the total cost shift.[116] The generation-related cost shift generally corresponds to the "overcompensation of exported energy" element discussed in the first bullet, above. The delivery-related cost shift generally corresponds to the "avoidance of fixed costs" element discussed in the second bullet, above. This representation should allow for easier tracking in future reports of a diminishing generation-related cost shift as legacy NEM customers transition to NBT or otherwise leave NEM tariffs. This effect will be small at first, given that there were very few NEM customers 20 years ago.[117] This effect will be obscured at first by the cost shift attributable to NBT systems, as well as increases in the cost shift due to projected rate increases.

[114] Total residential NEM cost shift is approximately $5.4 billion i.e., does not include non-residential cost shift and includes all residential customers i.e., bundled and unbundled. Data time series starts in 2016 and is from IOU data responses to SB 695 Report data requests. Data in current report may be restated from previous reports.
[115] The 2023 NBT cost shift totaled about $54 million across the three IOUs. The NBT cost shift may be represented graphically in future SB 695 Reports.
[116] Generation/Delivery Cost shift split estimated as follows: (1) Bill savings split by the percent of average bundled rate that is generation/delivery in each year; (2) Avoided cost split by the ratio of generation components (Energy, Generation Capacity, Cap and Trade, Ancillary Services, and Losses) and delivery components (Distribution Capacity, Transmission Capacity, GHG Adder, GHG Rebalancing, and Methane Leakage) in the 2023 forecast year of the 2022 ACC. This split of components is consistent with the NBT export credit generation and delivery component split; (3) Generation/Delivery avoided costs subtracted from corresponding bill savings to arrive at category level cost shift.
[117] Almost all of the customers in Table 4 are NEM customers.

Figure 17: PG&E NEM Cost Shift
by Generation- and Delivery-Related, Residential Customers ($ millions)

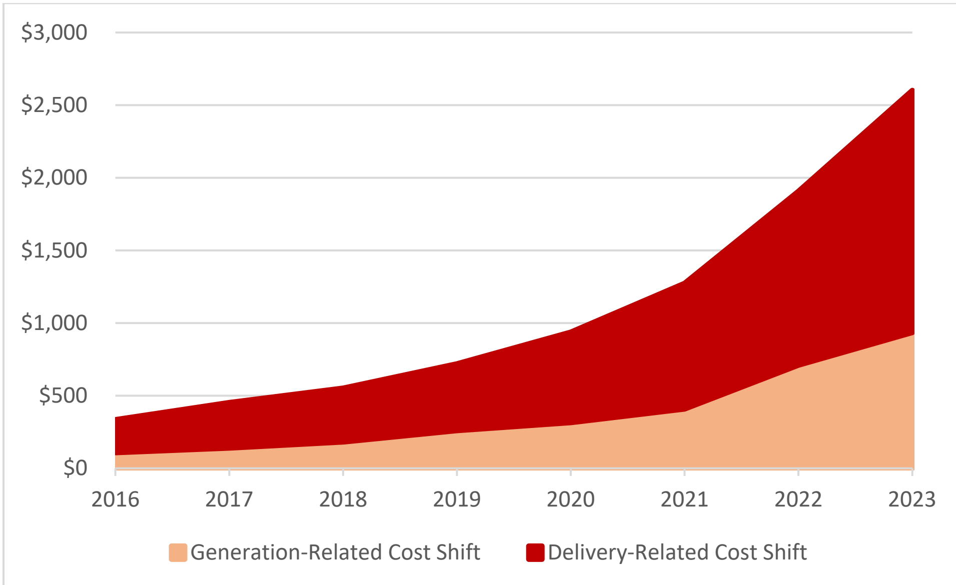


Figure 18: SCE NEM Cost Shift
by Generation- and Delivery-Related, Residential Customers ($ millions)

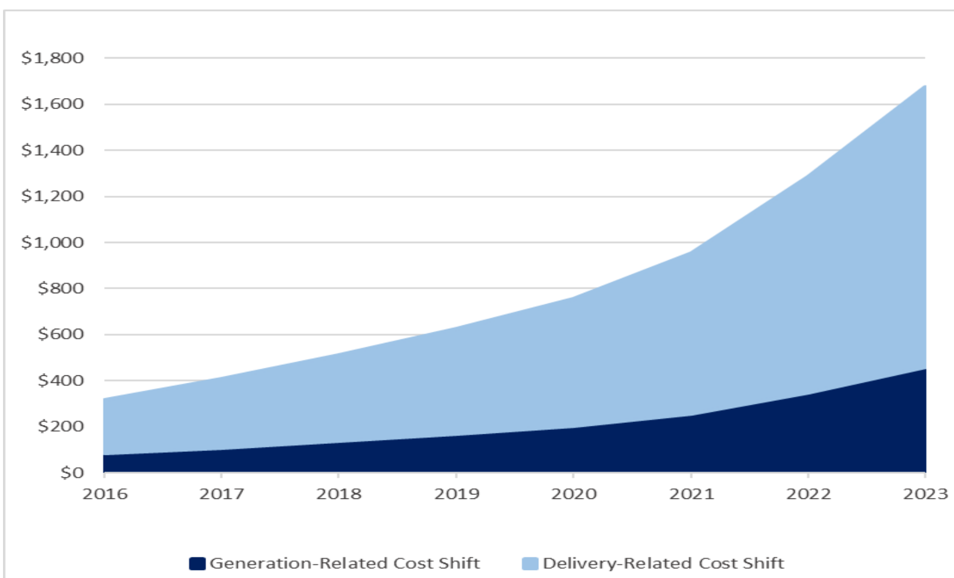
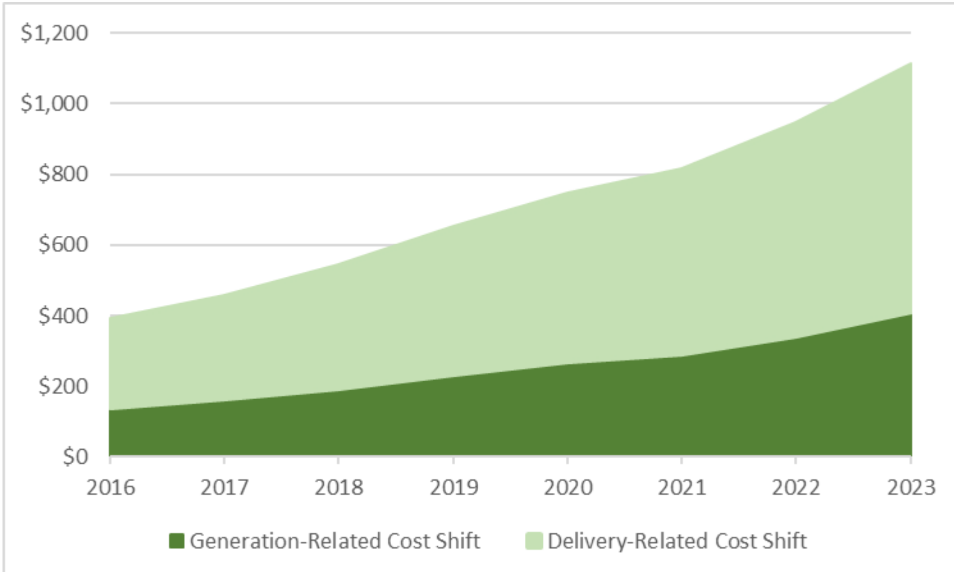


Figure 19: SDG&E NEM Cost Shift
by Generation- and Delivery-Related, Residential Customers ($ millions)



NEM Cost Shift Effect on Current Monthly Electric Bill

Table 5 shows the estimated effect on a typical bundled residential customer's average monthly bill resulting from the 2023 bundled residential NEM cost shift embedded in the above Figures 18 - 20, as calculated by each IOU.[118] The estimated bill portion is shown as the difference between existing bills and what counterfactual bills would have been if there were no NEM cost shift.

[118] Year-end 2023 rates in effect. Typical customer using 500 kWh (PG&E climate zone X, SCE climate zone 9) and 400 kWh (SDG&E Inland climate zone). Bills are for illustrative purposes only. SDG&E calculates the percent of total revenue paid by CARE customers and then applies that same percentage to the NEM cost shift; this may be different than PG&E and SCE methodologies.

Table 5: PG&E, SCE, and SDG&E NEM Cost Shift
Bundled Residential Customers Year-End 2023 Average Monthly Bill

Utility/ Residential Customer	Customer Monthly Bill with NEM Cost Shift	Customer Monthly Bill without NEM Cost Shift	Estimated NEM Cost Shift ($)	Estimated NEM Cost Shift (%)
PG&E Non-CARE	$191	$165	$26	14%
PG&E CARE	$122	$105	$17	14%
SCE Non-CARE	$175	$156	$19	11%
SCE CARE	$118	$105	$13	11%
SDG&E Non-CARE	$183	$147	$36	20%
SDG&E CARE	$119	$89	$30	25%

NEM/NBT and Interaction With Grid Planning

While rooftop solar and storage benefits the grid with proper price signals and compensation structures, the scale of rooftop solar brings challenges to grid planning. Unlike energy efficiency measures, NEM systems do not permanently decrease total onsite energy consumption. Instead, NEM customers substitute rooftop solar production for electricity from the grid during some hours of the day. They draw from the grid and export to the grid in different amounts at different times as their consumption increases and decreases and as solar production varies throughout the day and year. These customers actively use the grid to balance and support their NEM systems, but they draw fewer overall units of electricity from the grid.

The magnitude of rooftop solar on the grid has also created challenges with grid infrastructure planning. The need to electrify has put pressure on the capacity of the distribution system, which makes it difficult to evaluate and estimate exports from rooftop solar systems from a planning perspective. Other issues that must be considered include how to address phantom loads at the end of the day, as well as voltage support and balancing needs.

Recent Actions Taken by the IOUs to Limit Cost and Rate Increases (from Each IOU's Report to Limit Cost and Rate Increases)[119]

PG&E estimates that the NBT Decision, by compensating all exported electricity according to the CPUC's Avoided Cost Calculator, combined with other changes, will reduce the cost shift from future NBT eligible installations compared to NEM installations by about 50 percent. The burden on customers without solar will grow at a slower pace than it has historically. PG&E further states

[119] Full IOU reports available here; *See* "2024 Electric and Gas Costs Utility Reports" bullet point under the "Reports and White Papers" section of the webpage. Inclusion of IOU report elements in this report does not imply CPUC endorsement. SCE does not include NEM cost shift issues in its reports. SDG&E NEM cost shift issues in its reports refer mainly to the NBT Decision.

that it received an unprecedented number of applications between the issuance of the NBT Decision and the sunset date from customers and installers seeking to interconnect under the legacy tariff. Between the backlog of NEM 2.0 eligible applications that will continue to interconnect over the next three years and the significant residual cost shift resulting from NBT installations, NEM/NBT will continue to be a source of affordability pressure for the foreseeable future.

Recent Actions Taken by the CPUC to Limit Cost and Rate Increases[120]

In addition to the actions taken described above with respect to the NBT Decision, the CPUC created a new virtual net billing tariff (VNBT) and an Aggregation subtariff of the NBT as successors to the virtual NEM tariff and NEM Aggregation subtariff, respectively.[121] These actions are expected to reduce the cost impacts of new renewable energy projects on these tariffs in a similar way to the NBT.

VNBT customer-generators are multi-tenant properties, such as apartment buildings or commercial strip malls. An NBT Aggregation customer has adjacent parcels with multiple utility accounts, such an agricultural farm. As in the NBT, VNBT and NBT Aggregation retail export compensation is based on the hour of the day that the energy is exported to the grid.

VNBT generation credits ($) will be allocated monthly to each participating non-residential account (called a "benefiting account") as a bill credit. Net generation credits ($) will be allocated to each residential benefiting account if they are net producers within a 15-minute interval; residential benefiting accounts are permitted to virtually net their export generation against consumption. The property owner sets how the generation credit is shared. Qualified residential customers will receive the ACC Plus adder[122] on top of their energy export compensation for net exports; over 5 years the adder steps down to zero.

The NBT Aggregation subtariff allows customers to transfer bill credits to benefiting accounts on contiguous properties. It aligns with the NBT as closely as possible including import rates that apply for residential customers and export compensation based on the avoided cost calculator values.

These modifications will align ratepayer investments with the grid benefit from customer generation while reducing costs to customers that do not participate in the program. The VNBT and NBT Aggregation subtariff will encourage participating customers to install storage with solar to receive compensation during peak periods when the value of exported energy to the grid will be the highest.

Another type of action to improve rate affordability was the California Legislature's funding of solar and storage incentives through the California State Budget. AB 209 (Committee on Budget, 2022) amended the Self-Generation Incentive Program (SGIP) governing statute to authorize incentives,

[120] Actions taken during 2022 – 2023.
[121] *See* D.23-11-068.
[122] The ACC Plus adder is a $ per kWh exported incentive structure created in D.22-12-056 and used again in D.23-11-068. ACC stands for avoided cost calculator, the basis of retail export compensation.

subject to a future legislative appropriation, for residential customers who install new behind-the-meter solar paired with storage or new storage systems. For this purpose, $280 million was allocated from the 2023-2024 budget to fund the installation of systems for a projected 8,303 low-income residential customers over the program years 2024-2028. This funding will help provide financial benefits for eligible customers, contain costs to ratepayers, and provide support to the electric grid during the evening hours.

Wildfire-Related Costs

Climate change has introduced extraordinary challenges, most notably catastrophic wildfires that threaten distribution and transmission infrastructure that make vegetation more flammable. Historic wildfire-related legislation enacted in 2018 and 2019 forms the backdrop for the historical wildfire-related costs since 2019 presented here.

Legislative and Regulatory Background

SB 901 (Dodd, 2018) and AB 1054 (Holden, 2019) require electric utilities to prepare and submit wildfire mitigation plans (WMP) to the Office of Energy Infrastructure Safety (Energy Safety) which describe the level of wildfire risk in their service territories and how they intend to address those risks. The WMPs cover a three-year period with new comprehensive plans to be filed at least once every three years and annual updates to the plans in between. The current 2023 three-year cycle is the second three-year cycle for which electrical corporations are required to submit WMPs.[123]

SB 901 and AB 1054 required the CPUC to allow the IOUs to open memorandum accounts to track spending to implement their WMPs. The IOUs now forecast the majority of their WMP costs in their General Rate Cases (GRC). However, the IOUs are allowed to seek recovery of any incremental spending recorded in the memorandum accounts in their GRCs or through a separate application.[124] The IOUs also recover certain wildfire-related costs that are external to the activities described in the WMP, including for wildfire insurance premiums and recovering from catastrophic events. Wildfire insurance costs that are incremental to the insurance costs authorized in the GRCs may be tracked for recovery through the Wildfire Expense Memorandum Account (WEMA) for PG&E and SCE, and the Liability Insurance Premiums Balancing Account (LIPBA) for SDG&E.[125] The IOUs also track eligible costs to respond to catastrophic events, including wildfires, in their Catastrophic Event Memorandum Accounts (CEMA).[126] Permissible CEMA expenses include

[123] IOU 2023 - 2025: Base WMPs were submitted to Energy Safety on March 27, 2023 and each IOU's 2025 WMP Update was submitted to Energy Safety on April 2, 2024; 2025 WMP Update cost data has not been reviewed for inclusion in this report at time of writing. *See* each IOU's 2023 – 2025 Base WMP and 2025 WMP Update at: https://energysafety.ca.gov/what-we-do/electrical-infrastructure-safety/wildfire-mitigation-and-safety/wildfire-mitigation-plans/2023-wildfire-mitigation-plans/.

[124] For example, SCE's A.23-10-001 requests recovery of incremental wildfire mitigation spending recorded in memorandum accounts, among other requested cost recovery.

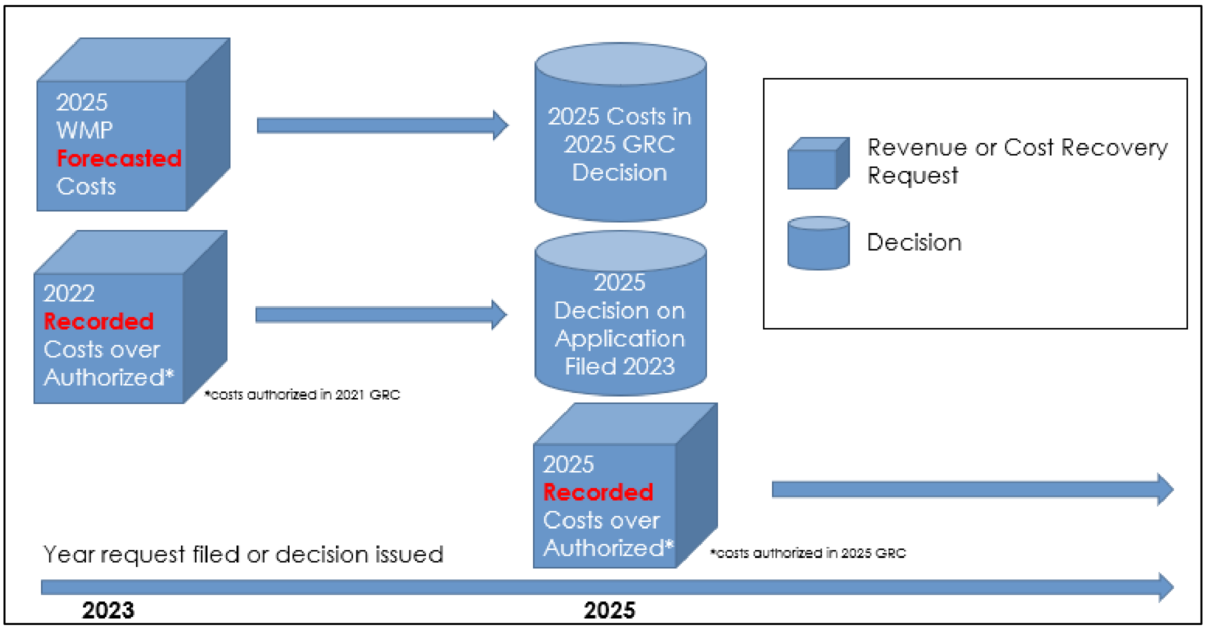
[125] Wildfire-related liability costs are claims paid as a result of property losses, in addition to other incremental liability costs including higher-than-forecasted insurance premiums and legal fees.

[126] Permissible CEMA expenses include restoring utility services to customers; repairing, replacing, or restoring damaged utility facilities; and complying with government agency orders resulting from declared disasters.

restoring utility services to customers; repairing, replacing, or restoring damaged utility facilities; and complying with government agency orders resulting from declared disasters.[127]

Costs incremental to forecasted costs approved in a utility's GRC (i.e., costs recorded in memorandum or balancing accounts[128]) may be incurred in one year and authorized for recovery in a later year.[129] In any given year, the CPUC may issue decisions on several applications by one utility requesting wildfire-related revenue or cost recovery. For example, Figure 21 shows the theoretical case of a utility's 2025 GRC WMP revenue requests coupled with a cost recovery request outside of the GRC proceeding.[130] This figure illustrates how previous costs incurred but not yet authorized for recovery compound known amounts forecasted and approved in a utility's GRC when these costs are eventually authorized for recovery.

Figure 20: Example of Multiple Wildfire-Related Decisions for One Utility in One Year



In addition to provisions regarding memorandum accounts, AB 1054 contains two separate benefits for ratepayers related to WMP capital spending. AB 1054 excludes the first $5 billion of the large IOUs' WMP capital spending[131] from earning a Return on Equity (ROE). This limits rate increases directly by eliminating the shareholder profit portion of the return on rate base of $5 billion in WMP

[127] Recovery of FERC-related costs is done in Transmission Owner rate cases.
[128] Balancing accounts used to record certain costs may have balances that exceed authorized forecasted costs. Wildfire-related balancing accounts include Vegetation Management Balancing Accounts (VMBA) and Wildfire Mitigation Balancing Accounts (WMBA).
[129] A utility's business decision about when to apply for cost recovery, along with the regulatory process, may add several years from the time costs are incurred until the time they are authorized for recovery.
[130] Example is hypothetical and not indicative of CPUC projection of actual timing of events or outcomes.
[131] 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.

capital spending. These equity rate base exclusions should save ratepayers as much as $2 billion that would otherwise be collected in rates over time.[132] AB 1054 also allows for this $5 billion capital spending to be securitized through a CPUC financing order rather than being financed through the more traditional unsecured bond offerings. This securitization benefits ratepayers by allowing the bonds to obtain a lower interest rate than would otherwise be available to finance WMP capital expenditures because the bonds are secured by a fixed recovery charge on customer bills.[133]

AB 1054 also created a $21 billion Wildfire Fund for excess liabilities resulting from utility-caused wildfires, funded equally by ratepayers and utility shareholders.[134] A non-bypassable charge (NBC) is collected from non-exempt ratepayers to support the fund, with CARE and Medical Baseline customers exempt from paying the NBC.

Climate change, primarily caused by the burning of fossil fuels, is increasing the frequency and severity of wildfires in California.[135] Over the next several years, wildfire mitigation costs driven in part by climate change are projected to continue their upward trend. Wildfire mitigation spending presented in each IOU's 2023 – 2025 Base Wildfire Mitigation Plan (WMP) shows significantly higher planned spending of about $26.2 billion for the 2023 – 2025 cycle than actual spend of about $20.7 billion in the previous 2020- 2022 cycle.[136]

Costs in Rates

Since 2019 and as of fourth quarter 2023, the IOUs have been authorized[137] to collectively place in rates approximately $16 billion of wildfire mitigation costs to support the state's wildfire prevention efforts and approximately $11 billion for wildfire insurance premiums and catastrophic events

[132] Finding of Fact 2 of each CPUC Financing Order states the estimated Net Present Value (NPV) savings of each bond issuance authorized. D.20-11-007: $173 million; D.21-06-030: $633 million; D.21-10-025: $403 million; D.22-08-004: $659 million; D.23-02-023: $493 million; D.24-02-011: $465 million. The CPUC also approved SDG&E AL 4078-E that demonstrated $84.3 million NPV savings.

[133] D.21-06-030 approved PG&E's first AB 1054 financing order requesting $1.2 billion in AB 1054 CapEx, of which bonds representing about $850 million were issued, D.22-08-004 approved its second AB 1054 financing order totaling about $1.4 billion in AB 1054 CapEx, of which bonds representing about $975 million were issued; and D.24-02-011 approved PG&E's request to securitize the remaining $1.385 billion AB 1054 CapEx---the bonds have not yet been issued at this time. D.20-11-007, D.21-10-025 and D.23-02-023 approved SCE's first, second and third (final) AB 1054 financing orders totaling about $1.575 billion in AB 1054 CapEx of which bonds representing the same amount of CapEx were issued. Recovery bond financing costs apply to all AB 1054 securitizations.

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

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

[136] Of the actual spend, the revenue requirement corresponding to about 80 percent of the spend has been collected in rates, with only a small portion of the capital-related portion of that revenue requirement reflected to date. The revenue requirement corresponding to the remaining 2020 – 2023 actual spend is either: (1) in the process of being approved i.e., requested for cost recovery in an open proceeding or (2) not yet filed for recovery. Cost recovery may be approved in amounts less than requested.

[137] Includes CPUC and FERC authorizations, except for PG&E which declined to provide FERC-related wildfire insurance and catastrophic events data and SDG&E which states it is not able to provide FERC-related wildfire mitigation data because WMP is a CPUC-jurisdictional balanced program.

costs.[138] Together, wildfire mitigation and wildfire insurance (and catastrophic events) costs[139] are referred to as "wildfire-related" costs. Total wildfire-related costs placed in rates[140] between 2019 and 2023[141] are approximately $27 billion as shown in Table 6.[142]

Table 6: Total Wildfire-Related Costs in Rates
(2019 – 2023, Year-End, $ billions)

Utility	Total Wildfire-Related Costs in 2019 – 2023 Rates (sum of columns to right)	Total Wildfire Mitigation Costs in 2019 - 2023 Rates	Total Wildfire Insurance / Catastrophic Events Costs in 2019 – 2023 Rates
PG&E	**$15.1**	$9.8	$5.3
SCE	**$10.3**	$5.7	$4.6
SDG&E	**$2.0**	$0.9	$1.1
Total	**$27.4**	$16.4	$11.0

Dollar-for-dollar, costs resulting in operating expense revenue requirement have a larger immediate impact on rates than costs resulting in capital-related revenue requirement. Capital-related revenue requirement has a larger cumulative impact on rates relative to operating expenses in the long run on a dollar-for-dollar basis as it is recovered over a much longer time horizon during which the IOUs also earn an authorized rate of return on rate base. Figure 22 shows this relationship using a hypothetical wildfire-related cost of $1 billion authorized for recovery in Year 1. The equivalent operating expense revenue requirement is $1 billion and the equivalent capital-related revenue requirement is $1 billion plus a theoretical 10 percent return on the undepreciated capital asset ("return on rate base") over the theoretical capital asset life of 40 years, or a total of $3.05 billion.[143]

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[138] Prior to 2023, PG&E insurance amount is total insurance, as general liability and wildfire liability insurance is not split in company records. PG&E indicates excess liability represents the primary component of general liability, and wildfire excess liability cost is greater than non-wildfire. Starting in 2021, SCE insurance amounts are wildfire only. A small portion of SDG&E insurance balance is unrelated to wildfire.

[139] Catastrophic events costs are substantially related to fire-related events, however, costs for other non-wildfire related events such as severe storms and wind events are also included.

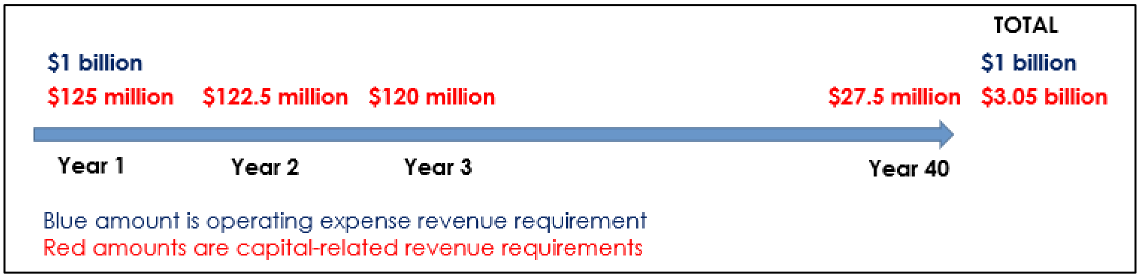
[140] Additional costs may have been incurred during the 2019 – 2023 period but may not have yet been placed in rates. There is not a 1:1 relationship between costs and revenue requirement placed in rates.

[141] Year-end data is used for this table and the tables that follow to capture all wildfire-related costs within the most recent calendar year.

[142] Data time series starts in 2016 and is from IOU data responses to SB 695 Report data requests. Data in current report may be restated from previous reports.

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

Figure 21: Comparison of Timing of Recovery of $1 Billion in Wildfire Costs (Operating Expense Revenue Requirement versus Capital-Related Revenue Requirement)



Despite some ratepayer relief afforded by AB 1054's equity rate base exclusion provisions which reduced wildfire mitigation capital expenditures included in rate base,[144] the wildfire mitigation portion of distribution rate base generally continues to increase as new authorized capital expenditures are brought into service and layered over existing capital expenditures with long depreciation periods.[145]

While wildfire-related capital expenditures—such as installing covered conductor or undergrounding portions of a distribution system—are not yet a significant portion of the total revenue requirement in rates, the wildfire-related percentages of PG&E and SCE's distribution rate base[146] have generally increased over the 2021 – 2024 period as shown in Table 7.[147] As rate base grows,[148] the capital-related revenue requirement corresponding to rate base also grows as the function of two effects: increased depreciation expense and increased return on rate base.[149] This means that the wildfire-related capital revenue requirement is becoming a more significant proportion of the total revenue requirement in rates over time.

[144] Reducing wildfire mitigation capital expenditures included in rate base produces ratepayer saving on the capital-related revenue requirement associated with these expenditures.

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

[146] Rate base is the net infrastructure investment at a given point in time.

[147] Data time series starts with the first available reporting year and is from IOU data responses to SB 695 Report data requests. Data in current report may be restated from previous reports. Distribution rate base reflects net plant/capital additions only i.e., "other" distribution non-plant/capital additions rate base is not included. Wildfire mitigation portion of transmission rate base is not available.

[148] Rate base generally grows as new capital expenditures are authorized and layered over existing capital expenditures with long depreciation periods.

[149] *See* Chapter II section "Electric Revenue Requirement" for rate base formula.

Table 7: PG&E, SCE, and SDG&E Wildfire Mitigation Portion (%) of Distribution Rate Base (January 1)

	2019	2020	2021	2022	2023	2024
PG&E	N/A	N/A	N/A	10.6%	10.6%	7.6%
SCE	N/A	N/A	1.6%	3.1%	5.3%	7.5%
SDG&E	2.0%	5.7%	6.0%	6.2%	6.4%	6.8%

Revenue Requirement in Rates

For PG&E and SCE, significant wildfire-related operating expenses, including vegetation management efforts and wildfire liability insurance coverage, began to appear in revenue requirement in rates relative to total revenue requirement starting in 2021, as shown in by the blue bars in Figure 23.[150] Wildfire-related capital expenditures (the red slivers on top of the blue bars), such as installing covered conductor or undergrounding portions of a distribution system, have continued to gradually increase over the 2021 – 2024 period but are not yet a significant portion of the total revenue requirement in rates.

SDG&E shows a lower percentage of wildfire-related revenue requirement to total revenue requirement; however, SDG&E has been revamping and enhancing its wildfire prevention and mitigation measures since 2007, well before the other IOUs, and cost figures reflect a more mature wildfire safety program than those of PG&E and SCE.[151] Further, while PG&E and SCE have already begun collecting wildfire mitigation costs booked in memorandum accounts established by SB 901, SDG&E did not file its request for recovery of similar costs until late 2023.[152]

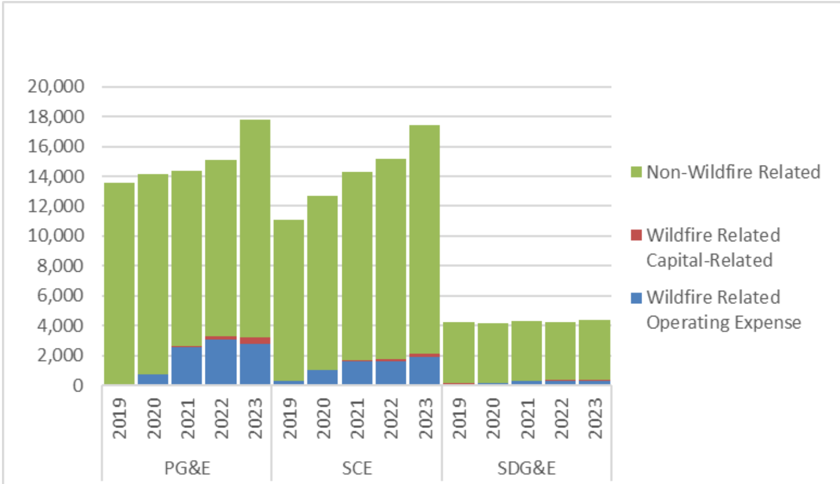
The year-end 2023 wildfire-related revenue requirement amount is shown in Figure 23 for each IOU.

- PG&E: $3.2 billion, or about 18 percent of total revenue requirement
- SCE: $2.1 billion, or about 12 percent of total revenue requirement
- SDG&E: $372 million, or about 9 percent of total revenue requirement

These wildfire-related revenue requirements, particularly the operating expense revenue requirement, are driving some of the increase in overall utility distribution revenue requirement seen in Figure 7 earlier in this report.[153]

[150] Data time series starts in 2019 and is from IOU data responses to SB 695 Report data requests. Data in current report may be restated from previous reports.
[151] *See* the 2021 SB 695 Report for additional detail about SDG&E operating expenses and capital costs incurred for wildfire prevention over the period 2007 – 2018.
[152] SDG&E filed a Track 2 as part of its GRC A.22-05-016 in October 2023 to request recovery of costs booked between 2019-2022 in its Wildfire Mitigation Plan Memorandum Account.
[153] CPUC-jurisdictional wildfire-related costs are generally recovered through the distribution rate component; other rate components are the Wildfire Fund Charge (all IOUs) and a wildfire hardening Fixed Recovery Charge (PG&E and SCE).

Figure 22: Wildfire-Related (WR) Revenue Requirement Relative to Total Revenue Requirement (Year-End, $ millions)



Wildfire-Related Portion of Monthly Bill

Table 8 shows the wildfire-related portion of a bundled residential Non-CARE[154] customer average monthly bill resulting from the year-end 2023 wildfire-related revenue requirement (blue and red bars) represented in Figure 23.[155]

Table 8: PG&E, SCE, and SDG&E Wildfire-Related Portion of Year-End 2023 Average Monthly Bill, Bundled Residential Non-CARE Customers

	Total Bill	Wildfire-Related Portion ($)	Wildfire-Related Portion (%)
PG&E	$190.94	$24.42	12.8%
SCE	$174.79	$17.73	10.1%
SDG&E	$182.82	$12.97	7.1%

Undergrounding Portion of Monthly Bill

The CPUC recently adopted the SB 884 (2022, McGuire) program guidelines that address the process and requirements for the CPUC's review of a large electrical corporation's 10-year distribution infrastructure undergrounding plan and conditional approval of its related costs.[156] Starting with this year's SB 695 Report, the estimated undergrounding costs in year-end 2023 bills

[154] Residential customers not enrolled in the California Alternate Rates for Energy (CARE) program. Lower-income residential customers enrolled in the CARE program receive up to a 35 percent discount on bills.
[155] Year-end 2023 rates in effect. Typical Non-CARE customer using 500 kWh (PG&E climate zone X, SCE climate zone 9) and 400 kWh (SDG&E Inland climate zone). Bills are for illustrative purposes only.
[156] *See* Resolution SPD-15.

for PG&E and SCE are presented.[157] This data may not fully reflect future costs of any SB 884 plans because the IOUs are in still in the process of developing system hardening economic models. Table 9[158] shows estimated undergrounding costs in year-end 2023 bills for PG&E[159] and SCE.[160]

Table 9: PG&E and SCE Undergrounding Portion of Year-End 2023 Average Monthly Bill, Bundled Residential Non-CARE Customers

	Total Bill	Undergrounding Portion ($)	Undergrounding Portion (%)
PG&E	$190.94	$0.27	0.1%
SCE	$174.79	$0.10	0.1%
SDG&E	$182.82	Not Provided	Not Available

Recent Actions Taken by the IOUs to Limit Cost and Rate Increases (from Each IOU's Report to Limit Cost and Rate Increases)[161]

PG&E reports operational cost reductions: (1) a 2023 vegetation management cost reduction of about $300 million, achieved through bundling work by location instead of making several trips, standardizing unit rate contracts, and focusing on meeting quality standards the first time; and (2) a 2023 undergrounding cost reduction of about $70 million, achieved by reducing the trench depth from 36" to 30" and doing longer cable runs, as well as fewer boxes per mile.

PG&E further reports that it supports CPUC authorization to securitize wildfire mitigation-related operating and maintenance (O&M) costs (i.e., operating expense) as an additional financial tool to mitigate rate impacts. It furthers states that the CPUC previously authorized securitization of wildfire capital expenditures based on the economic benefits (i.e., customer cost reduction) as the sole standard of measure for the value of the proposal for securitization. However, securitizing wildfire mitigation-related O&M costs may result in other important customer benefits, such as promoting rate stability or reducing near-term costs (e.g., to mitigate rate impacts of vegetation

[157] SDG&E did not provide undergrounding costs or equivalent revenue requirement data, stating that with respect to its current GRC proceeding, it does not separately calculate the revenue requirements of specific/individual capital programs. SDG&E requests one total company revenue requirement, segmented between electric distribution, generation, and gas.

[158] This data is embedded in Table 8 and is not additive. SDG&E did not provide undergrounding costs or equivalent revenue requirement data, stating that with respect to its current GRC proceeding, it does not separately calculate the revenue requirements of specific/individual capital programs. SDG&E requests one total company revenue requirement, segmented between electric distribution, generation, and gas.

[159] PG&E did not have 2023 GRC costs in rates at year-end 2023; undergrounding costs included in PG&E's 2023 year-end rates in Table 9 are solely from the 2020 GRC's 2022 Attrition Year, i.e., there are no undergrounding costs recorded in memorandum or balancing accounts authorized for recovery in year-end 2023 rates.

[160] Undergrounding costs included in SCE's 2023 year-end rates in Table 9 are solely from the 2021 GRC's 2023 Attrition Year, i.e., there are no undergrounding costs recorded in memorandum or balancing accounts authorized for recovery in year-end 2023 rates.

[161] Full IOU reports available here; *See* "2024 Electric and Gas Costs Utility Reports" bullet point under "Reports and White Papers" section of the webpage. Inclusion of IOU report elements in this report does not imply CPUC endorsement. SDG&E does not include wildfire-related issues in its report.

management until ongoing system hardening work can be completed). PG&E is exploring ways to use existing statutory mechanisms to securitize wildfire mitigation-related O&M costs as well as potential legislation to minimize electric bill rate spikes for ratepayers by providing financing options for an electric utility corporation to help reduce near-term costs and promote rate stability associated with wildfire mitigation efforts.

On the subject of securitization of WMP spending, SCE states existing authorizing legislation (i.e., Assembly Bill (AB) 1054) allows for the securitization of wildfire mitigation-related O&M expenses, other wildfire-related costs above insurance, and wildfire-related restoration expenses. Further, it asserts the CPUC determined that AB 1054 does not preclude the CPUC from considering securitization of wildfire mitigation expenses that provide both short-term and long-term economic benefits to customers.[162] SCE believes that utilizing this securitization authority would minimize bill increases, particularly for its most economically vulnerable customers. This is because under the current statute, SCE's income-qualified customers are exempt from the Fixed Recovery Charges (FRCs) used to recover securitized costs.[163] There are also near-term rate reductions for customers who are responsible for securitized costs because these amounts go into rates at a significantly lower amount compared to traditional compensatory recovery of O&M expenses.[164]

Recent Actions Taken by the CPUC to Limit Cost and Rate Increases[165]

D.23-01-005 and D.23-05-013 approved proposals of PG&E and SCE (respectively) to implement ratepayer-funded wildfire self-insurance, estimated to have resulted in a $467 ratepayer savings impact in 2023. Under the self-insurance framework, future costs are expected to be less expensive than under a commercial insurance framework, as insurance costs collected from ratepayers would be available for subsequent years if not needed to cover losses in a given year. Alternatively, under commercial insurance, insurers generally keep the premiums paid regardless of the amount of claims made against the policy.

D.23-11-069 for PG&E and D.21-08-036 for SCE imposed "soft caps" on vegetation management costs to limit the IOUs' ability to recover vegetation management costs above authorized amounts without a reasonableness showing. PG&E's recovery is capped at the authorized amount per D.23-11-069, and D.21-08-036 caps SCE's cost recovery at 15 percent above the authorized amount. In both cases, the utilities are required to demonstrate reasonableness for any spending above the cap

[162] *See* D.21-10-025, p.15.

[163] SCE states that if it had been allowed to securitize approximately $478 million of 2018-2019 wildfire mitigation O&M and a portion of its 2020 incremental uncollectibles as, for example, proposed in its June 2021 Application for Authority to Issue Recovery Bonds, CARE customers would have seen an annual bill reduction of approximately $38 compared to traditional financing.

[164] In the prior example, instead of increasing rate levels by $478 million in a single year, the rate increase in the first year related to the securitized costs would have been approximately $25 million.

[165] Actions taken during 2022 – 2023.

before recovery is authorized and they must return any unused authorized amount to ratepayers through the balancing account ratemaking mechanism.

Clean Energy and Electrification Costs

In addition to traditional IOU objectives of reliable, safe, and affordable electric service, legislative mandates to pursue policy objectives can add costs that result in higher revenue requirements. Transportation electrification (TE) legislative mandates along with private sector innovation will propel the transition to a fully electrified transportation sector over the next decade. Significant upgrades to the distribution grid, transmission infrastructure, and supporting generation resources will be necessary to accommodate charging demand. While the new load added to the system will have downward pressure on rates, 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 and regulatory mandates to support and accelerate widespread TE.[166] SB 350 (De León, 2015) directed the CPUC to require the IOUs to submit applications for programs that leverage ratepayer funding to support electric vehicle (EV) adoption.[167] To date, the CPUC has authorized the IOUs implementation of many TE programs to help meet California's zero-emission vehicle (ZEV) targets of five million ZEVs on the road by 2030, 250,000 installed publicly available EV charging stations, and 200 publicly available hydrogen fueling stations in the state by 2025.[168] The CPUC has also authorized implementation of policies to help meet California's goals toward requiring all in-state sales of new passenger vehicles be zero-emission by 2035, all medium- and heavy-duty vehicles in the state be zero-emission by 2045, and all drayage trucks and off-road vehicles and equipment be zero-emission by 2035, where feasible.[169]

Additionally, AB 841 (Ting, 2020) directs the establishment of new electric rules or tariffs that authorize each IOU to design and deploy all utility-side electrical distribution infrastructure for all customers, excluding single-family residential, installing separately metered EV charging and allocates those costs to all ratepayers. This means that ratepayers now cover costs previously covered by the customer requesting the new or upgraded service, as is the practice for non-TE customers receiving service through the utilities' Electric Rule 16. For utility charging programs, this changes the CPUC practice of authorizing utility-side, electrical distribution infrastructure needed to charge

[166] 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.
[167] Such as multi-unit dwellings, workplaces, destination centers, disadvantaged communities, and low/medium income residential communities.
[168] Executive Order (E.O.) B-48-18.
[169] E.O. N-79-20 and California Air Resources Board (CARB) regulations Advanced Clean Cars II (2022) and Advanced Clean Fleets (2023).

EVs[170] 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.[171] For charging infrastructure broadly, the bill and associated electric rules require ratepayers to cover more of the cost for new service and service upgrades that is covered under Rule 16 for other end uses rather than the charging infrastructure developers. This bill also made 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 rather than customers with EVs. New EV infrastructure rules pursuant to AB 841 were approved in October 2021[172] and the exemption to Rules 15 and 16 for residential customers was approved in December 2021.[173]

SB 350 (de Leon, 2015) directs the CPUC to require the IOUs to develop proposals to accelerate widespread TE. As a part of this, the Decision on Transportation Electrification Policy and Investment, approved in November 2022, establishes a framework with budget and policy directives to ensure a structured approach to TE investment for all electric IOUs in the state, through five-year funding cycles.[174] The Decision authorizes up to $1 billion for a statewide Funding Cycle One (FC1) program, which will begin on January 1, 2025. $600 million in funding will be available for the first three years of the program, with the remaining funds authorized pending a Mid-Cycle Review to determine whether additional funding is needed. The IOUs will disburse funds, based on their percentage of 2024 electric sales, to a statewide third-party Program Administrator, who will design and administer the FC1 program. The FC1 program will fund behind-the-meter infrastructure rebates, technical assistance, and marketing, education, and outreach. By using a rebate structure, the program eliminates the opportunity for IOU ownership of behind-the-meter infrastructure, which is expected to result in ratepayer savings in the long run. On April 12, 2024, a scoping memo and ruling announced the FC1 rebate program would be reassessed in light of affordability concerns, demand for utility-side infrastructure, and the existence of non-ratepayer funds for behind-the-meter infrastructure.[175]

On October 7, 2023, Governor Newsom signed two new pieces of legislation into law to promote timely energizations. First, AB 50 (Wood, 2023) established criteria for customers to receive timely energization and potential remedies to expedite energization. Second, SB 410 (Becker, 2023) requires the establishment of reasonable average and maximum target energization time periods in order to

[170] 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.

[171] The establishment of the EV Infrastructure Rules signals a major policy shift in transportation electrification at the CPUC, as the new approach incorporates utility-side transportation electrification investments into the IOUs' general rate case proceedings rather than individual program applications. The utilities began implementation of their EV Infrastructure Rules in April 2022, the CPUC receives EV infrastructure Rule data from the utilities annually on March 31.

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

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

[174] *See* D.22-11-040.

[175] Scoping Memo and Ruling at 5-8 (R.23-12-0008, April 12, 2024).

connect new customers and upgrade the service of existing customers to the electrical grid. To implement SB 410 and AB 50, the Commission (1) launched Rulemaking (R.) 24-01-018 to establish the energization timing targets and data reporting processes, (2) opened a second phase of PG&E's GRC to implement the legislative mandate to approve an expedited rate recovery mechanism upon request of an IOU, and (3) ensured that distribution system planning processes will include all required planning elements (R.21-06-017).

In addition to TE program expenses, in their GRCs the IOUs may file for recovery of distribution capacity costs related to EV load growth. To support the state's electric vehicle adoption, the large IOUs forecast substantial investments to upgrade electrical distribution and/or transmission capacity to provide adequate capacity to new and existing EV customers. Pursuant to SB 410, PG&E has requested TE-related distribution upgrades as part of approximately $4.1 billion to support energization-related distribution upgrades for the period 2024 to 2026 in a subsequent phase of its 2023 GRC application.[176] SCE requested approximately $2.5 billion for the period 2025 through 2028 to support TE-related distribution upgrades in its 2025 GRC application. These costs are currently being reviewed in each respective proceeding and the costs, at their approved revenue requirement equivalent, will be in rates at a future date.

Costs in Rates

The TE programs costs include electric vehicle supply equipment (EVSE), make-ready, administrative, and marketing outreach, and education (ME&O) costs. EVSEs are the devices that provide electric power to charge electric vehicle's batteries. Make-ready infrastructure refers to service connection and supply infrastructure installed on the utility-side (aka to-the-meter or TTM) and customer-side (aka behind-the-meter or BTM) of the meter needed to support the installation of EVSE. The make-ready costs account for the majority of the infrastructure costs.

Pursuant to SB 350, as of fourth quarter 2023, the CPUC has authorized the large electric IOUs to spend approximately $2.6 billion on TE programs to support the state's TE goals. Out of the authorized IOU funding to date, $411 million has been spent[177] by PG&E, SCE, and SDG&E and approximately $2 billion is still available for TE investment.[178] Capacity costs in rates related to EV load growth are not currently broken out from overall capacity costs and are not included here.

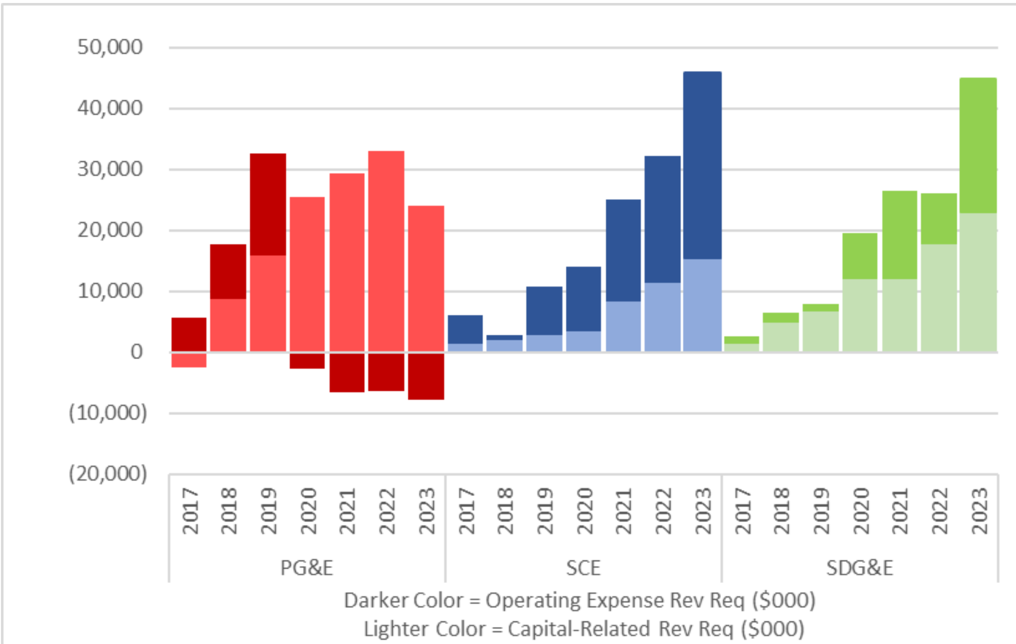
Revenue Requirement in Rates

Figure 24 shows for each IOU the relative share of the total operating expense and total capital-related revenue requirement[179] reflected in 2017 - 2023 rates corresponding to each IOU's

[176] The request does not break down energization-related distribution upgrades into categories such as TE-related.
[177] This amount includes direct spending by all three IOUs as of December 2023.
[178] The large electric IOUs' initial TE programs with an authorized budget of approximately $200 million have been completed and these funds are no longer available for TE investment.
[179] 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.

transportation electrification programs costs. Operating expense revenue requirement may include balancing accounts that reflect negative (over-collected) balances. A capital-related amount may be negative due to first year depreciation flow-through.[180]

Figure 23: PG&E, SCE, and SDG&E Transportation Electrification Programs Revenue Requirement in Rates (Year-End, $000)



Transportation Electrification Programs Portion of Monthly Bill

As indicated in previous SB 695 reports, TE programs continue to have a modest impact 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.[181] Table 10 shows the TE programs portion of a bundled residential Non-CARE[182] customer average monthly bill in 2023.[183]

[180] For new capital spending, under certain tax ratemaking treatment, the benefit of the tax deduction "flows-through" to customers in the first year the capital asset is in service, with the tax benefit paid back over time as the utility receives revenue to amortize the capital asset ("flow-back").
[181] Near-term defined as out to 2027.
[182] Residential customers not enrolled in the California Alternate Rates for Energy (CARE) program. Lower-income residential customers enrolled in the CARE program receive up to a 35 percent discount on bills.
[183] Year-end 2023 rates in effect. Typical Non-CARE customer using 500 kWh (PG&E climate zone X, SCE climate zone 9) and 400 kWh (SDG&E Inland climate zone). Bills are for illustrative purposes only.

Table 10: PG&E, SCE, and SDG&E TE Programs Portion of Year-End 2023 Average Monthly Bill, Bundled Residential Non-CARE Customers

	Total Bill	TE Program Portion ($)	TE Program Portion (%)
PG&E	$190.94	$0.12	0.1%
SCE	$174.79	$0.41	0.2%
SDG&E	$182.82	$1.56	0.9%

California is undertaking a tremendous effort to accelerate TE infrastructure deployment in the coming years to meet the state's TE goals. The scale of the challenge is highlighted in the CEC Staff's first Assembly Bill (AB) 2127 Electric Vehicle Charging Infrastructure Assessment report, released in 2021.[184] While the report urges continued public financing of chargers and infrastructure in the near-term, it also highlights the importance of devising innovative financing mechanisms that can reduce the burden of these investments on ratepayers and the public, and of finding ways to utilize charging infrastructure to benefit the grid, thus potentially reducing 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;[185] 2) EnergIIZE, a CEC-funded infrastructure program for the medium and heavy-duty vehicle sector; 3) federal National Electric Vehicle Infrastructure Plan (NEVI) funding for EV charge corridors authorized through the 2021 Infrastructure and Jobs Act (IIJA); and 4) California Air Resource Board's (CARB) Low Carbon Fuel Standard (LCFS) credit revenue generated from EVs that is used in many cases to support additional charging infrastructure.

Other Topics of Interest

AB 205 (2022) required the CPUC to authorize a flat rate for the three major electric IOUs[186] that includes a minimum of three income-based thresholds (tiers) by July 1, 2024.[187] The flat rate is a reallocation of volumetric costs to fixed costs that should reduce rates and lower bills on average without a change in usage for lower-income customers in each baseline territory. Furthermore, the progressivity of the three-tiered structure is a critical, forward-thinking and innovative development in rate design that will in some measure help to level the playing field for lower-income customers who have borne a disproportionate share of fixed costs for distribution infrastructure development in recent years.

[184] At time of writing, the 2023 edition of the biennial AB 2127 Report has not been released.
[185] CALeVIP is currently funded for $124.9 million through CEC funding, with $32 million in co-founding partner contributions.
[186] AB 205 IGFC requirements also apply to the Small and Multi-Jurisdictional Utilities (SMJUs).
[187] *See* docket for R. 22-07-005.

The Flat Rate Decision, issued May 9, 2024, moves some existing fixed costs into a "flat rate" line item on bills, aligning California's flat rate with other state and nationwide utility flat rates.[188] Customers enrolled in the CARE low-income assistance program will benefit from a discounted flat rate of $6 per month. Customers enrolled in the Family Electric Rate Assistance Program (FERA), as well as those residing in deed-restricted affordable housing with incomes at or below 80 percent of the area median income, will qualify for a discounted flat rate of $12 per month.

At the same time, consumption-based rates will go down, for an overall decrease in the average low-income bill, enhancing affordability and encouraging electrification by all customers. This new billing structure would go into effect late 2025 and early 2026.[189]

Revision of Electric 20A Program

Rule 20 is the tariff that governs utility undergrounding of overhead wires at the request of third parties (e.g., local governments, businesses, and residential customers). The Rule 20 program is currently split into three subdivisions in the tariff based on how much funding ratepayers contribute to the project (Rule 20A, Rule 20B, and Rule 20C).

Historically, Rule 20A has allowed utilities to annually allocate funds defined as work credits to communities, either cities or unincorporated areas of counties, to convert overhead electric facilities to underground. Work credits act as a sort of voucher (or non-monetary dollars) assigned to a local government, which the local government can redeem to perform undergrounding projects in consultation with the serving utility on a one work credit-to-one dollar basis. The utility then recovers the cost of the completed project through rates.

D.23-06-008 discontinues and phases down the Rule 20A Program by 2033 to prevent ratepayers from funding inactive and inequitable infrastructure investments. The action is estimated to save $74 million annually through 2033.

Transmission Buildout Capital Expenditures

To meet California's clean energy goals, the California Independent System Operator (CAISO) has begun approving unprecedented levels of transmission investment.[190] In 2023, the CAISO approved over $8 billion, three times the highest amount previously approved, in new transmission expansion projects, consisting of circuit breaker and other upgrades, reconductoring, grid enhancing

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[188] California is one of the only states where investor-owned utilities do not have flat rates for infrastructure and maintenance costs. For example, some utilities in Texas have flat rates up to $39 per month. Almost all publicly-owned utilities in California have flat rates. At $24.15, the proposed flat rate is the same amount as the Sacramento Municipal Utility District's (SMUD) flat rate.

[189] Implementation varies by utility. SCE and SDG&E would be required to begin to apply the adopted changes to residential customer bills during the fourth quarter of 2025. For PG&E and the SMJUs, this requirement begins during the first quarter of 2026.

[190] *See* the 2023 AB 67 Report for more information regarding transmission costs that comprise the transmission revenue requirement, as well as more information on how the CPUC intervenes in TO rate cases at FERC on behalf of California ratepayers. Ratepayer savings from this intervention are estimated to be $5 billion since 2018.

technologies, and new lines. The costs of such high voltage transmission projects are allocated throughout California, with the greatest share attributed to the transmission assets of PG&E, SCE, and SDG&E. To the extent that these projects support increased load, however, they will also put downward pressure on rates as investments are spread among a greater number of customers and units of electricity.

In recent years, the majority of capital transmission investment spend has been on utility self-approved repair and replacement projects, which are repair and replacement projects needed for maintaining the grid, and not on CAISO-approved transmission projects that expand capacity of the grid. Between 2020 and 2022, of the total $6.8 billion in transmission investment by the three IOUs, $4.4 billion (64.8 percent) was invested in self-approved projects that received no formal review in their planning by the CAISO or CPUC.

In 2022, the CPUC established the Transmission Project Review (TPR) Process to provide transparency to specific projects, as well as programmatic buckets or blanket program categories (collectively "Projects"), that are CAISO-approved or Utility Self-Approved, as well as transmission network upgrades needed for generator interconnections projects, beginning January 1, 2024.[191] Projects will be included if they are expected to total $1 million or more in capital costs. The TPR Process requires that the IOUs semi-annually submit system-wide transmission data for projects with capital additions to rate base in the last five years and forecasted or actual capital expenditures in the current year and future four years, to enable understanding of project planning, prioritization, and implementation. The TPR Process is modeled after stakeholder processes negotiated in previous transmission owner rate case settlements at FERC. While not always quantifiable, savings from those FERC-derived processes between 2020 and 2023 resulted in quantified long-term savings to ratepayers of between $500 million and $1 billion.

Similar to capital investment spend for wildfire mitigation, the decades-long recovery timeframe for capital investments results in the related revenue requirement in any given year being a fraction of a capital project's cost. However, over the depreciable life of a capital investment, the depreciation expense[192] and corresponding rate of return (including return on equity for shareholders) result in long-term costs to ratepayers that can be multiple times higher than the initial project cost.[193] In May 2022, CAISO released its 20 Year Transmission Outlook, estimating that in the next two decades, $30.5 billion[194] of investment in new transmission capacity on the high voltage transmission system will be needed to meet the state's clean energy goals. This amount, which includes the $8 billion in recent CAISO-approvals previously mentioned, does not include ongoing self-approved projects and capacity build out of lower-voltage transmission. Together, all of this investment is expected to

[191] *See* Resolution E-5252.
[192] Net of related tax effect.
[193] *See* Figure 22 for an example of how a $1 billion capital expenditure cost over 40 years can balloon to 3x the original $1 billion investment.
[194] *See* California ISO, 20 Year Transmission Outlook, May 2022. Amount does not include approximately 40 percent of the costs to operate the current CAISO controlled transmission grid that are for the portion of the transmission grid that operates below 200kV.

lead to continuously mounting capital-related revenue requirements as transmission buildout progresses.

Removal of FERC Incentive Adder for IOUs' participation in the CAISO

AB 209 (2022) reaffirmed an existing CPUC decision that PG&E's, SCE's, and SDG&E's participation in the CAISO is not voluntary. In December 2023, FERC issued an Order that rejected PG&E's request for an incentive adder on its proposed return on equity for its continued participation in CAISO. The denial was predicated on the recently enacted California AB 209 that requires PG&E to participate in CAISO, therefore confirming that PG&E's participation in CAISO is not voluntary and PG&E is not eligible for the incentive adder.[195] This adder, which will no longer be allowed in future rate cases, has an estimated value of decreasing costs to ratepayers by $86 million in 2024.

Federal Grants

Resolution E-5254, issued in 2023, encouraged electric and gas IOUs to pursue federal grants under the Inflation Reduction Act, the Infrastructure Investment and Jobs Act (IIJA), and the Creating Helpful Incentives to Produce Semiconductors and Science Act (CHIPS), allowed utilities to create memorandum accounts to record costs associated with applications and required a quarterly reporting of planned and submitted applications to track IOU progress, as well as established a process to track cost recovery requests by the utilities for projects that may be funded partly by federal grants. Federal grants could lessen the impact of necessary infrastructure replacements and upgrades. The CPUC has also coordinated closely with other agencies[196] to submit coordinated applications that offer the best chance of success.

Recent Actions Taken by the IOUs to Limit Cost and Rate Increases[197]

PG&E states it supports outside sources of funding that can bring bill relief to customers, especially those most vulnerable. In 2024, PG&E continues to look for opportunities to provide rate relief for its customers. PG&E supports affordability solutions through non-traditional funding such as: (1) a legislatively proposed climate bond to fund clean vehicles, grid upgrades, wildfire mitigation, etc.; (2) funding capacity upgrades through the low carbon fuels standard (LCFS) program; and (3) using state directed Inflation Reduction Act dollars toward rate relief.

In addition, PG&E is pursuing Department of Energy (DOE) grants through the Grid Resilience and Innovation Partnership (GRIP) program. In January 2024, as both a lead applicant and in partnership with other entities such as other IOUs, state agencies, and non-profits, PG&E submitted 12 concept papers for DOE to evaluate. These projects have the potential to bring

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[195] *See* Order in FERC Docket No. ER24-96-000.

[196] Other agencies include entities such as GO-BIZ, the Infrastructure Investment Bank, the California Energy Commission.

[197] Full IOU reports available here; *See* "2024 Electric and Gas Costs Utility Reports" bullet point under "Reports and White Papers" section of the webpage. Inclusion of IOU report elements in this report does not imply CPUC endorsement.

hundreds of millions of federal dollars to California to fund the State's energy infrastructure needs and advance new technologies. The projects range in scope from creating additional grid resilience through expanded transmission capacity and reconductoring projects, to vehicle to grid integration technology, and solutions to accelerate renewable energy interconnections. PG&E will submit its applications in spring 2024, with additional opportunities to pursue GRIP dollars in the coming years.

SCE echoes PG&E comments regarding outside sources of funding such as LCFS to fund pilots, programs, and services that help accelerate customer adoption of electric vehicles. These efforts allow those customers to start realizing the cost benefits of fuel switching immediately and increases total electric system utilization, which directly applies downward pressure on electricity rates (which benefits all electricity customers, not just EV drivers). It adds that SCE has pursued and continues to apply for opportunities for alternative funding from outside sources, when appropriate, to decrease cost impacts to its customers. These opportunities are primarily from the Infrastructure Investment and Jobs Act, the Department of Energy, and the California Energy Commission.

V. Bundled Residential and Small Commercial Customer Electric Rates Forecasts

Electric IOU rates are projected to continue to rise to cover investments in wildfire mitigation measures, clean energy resources and electric systems reliability enhancements, as well as continue to reflect the cost impact of NEM/NBT programs. While risk reduction and grid upgrade investments will significantly reduce the reduce the risk of wildfire ignition from electrical equipment, yield substantial reductions in greenhouse gas emissions and criteria air pollution, and bolster system reliability during extreme weather events, the anticipated increase in rates is significant.

Forecasted Incremental Revenue Requirement and Projected Rate and Bill Impacts

As part of the Affordability proceeding,[198] the CPUC ordered PG&E, SCE, and SDG&E to each submit a quarterly cost and rate tracker (CRT) tool to Energy Division for evaluating the inputs of the affordability metrics.[199] In addition to producing bundled residential essential usage bills[200]for the affordability metrics, each IOU's CRT may be used to produce a four-year[201] rate forecast[202] to show overall bundled residential average rate trends and estimated bills at IOU climate zone level.[203] New to the CRTs this year is the addition of small commercial rate and bill forecasting.[204] Itemized lists of revenue requirements and revenue requests[205] prepared by the utilities as part of the CRTs, as well as rate and bill impacts resulting from these lists, are available on the CPUC's Affordability webpage.[206]

[198] *See* R.18-07-006.
[199] *See* D.20-07-032, Ordering Paragraph (OP) 1.
[200] Essential usage bills (EUB) reflect essential service, which is the minimum amount of service measured by the metrics. EUBs are used as an input to calculate certain affordability metrics.
[201] Current year and three additional years.
[202] SCE and SDG&E's CRTs are labeled confidential. Energy Division staff may modify the rate forecasts as submitted by the IOUs to reflect estimates for cost recovery applications not yet filed and to take into account historical trends in revenue requirement and rates. Forecasts do not take into account future natural gas price spikes, which are difficult to predict. Forecasts also do not take into account future NEM/NBT cost shifts, except to the extent that they may be reflected in historical trends in revenue requirement and rates.
[203] 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.
[204] Small commercial rates are PG&E B-1, SCE TOU-GS-1, and SDG&E TOU-A. Small commercial usage profiles are estimated using Food Services and Drinking Places (NAICS 722), Ambulatory Health Care Services (NAICS 621), and Real Estate (Property Management, NAICS 531). Rates and bills for other non-residential customer classes are not produced in the CRTs, as usage profiles needed to calculate bill impact for a typical non-residential customer in these other non-residential customer classes is difficult to define.
[205] Revenue requests in pending proceedings.
[206] *See* Itemized List of Revenue Requests.

Bundled Residential and Small Commercial Rate Forecasts

PG&E's, SCE's, and SDG&E's current electric CRTs[207] were used to produce rates forecasts. Projected rates in this report are forecasts, including assumptions related to those forecasts, and are therefore subject to material change as assumptions change. Further, forecasts are based on forward-looking estimates that are not historical facts. Forecasts are for illustrative purposes only and solely for use in this report.

Bundled residential average rate forecasts for year-end 2024 – 2027 are shown in Table 11.[208] The average annual percentage change in forecasted year-end 2027 rates over actual year-end 2023 rates for each IOU are greater than the assumed average annual rate of inflation of 2.6 percent.[209]

Table 11: PG&E, SCE, and SDG&E Forecasted Bundled Residential Average Rates (nominal $/kWh)

Bundled Residential Average Rate	Year-End				
	2023 Actual	2024	2025	2026	2027
PG&E Nominal Rate	$ 0.322	$ 0.371	$ 0.400	$ 0.435	$ 0.460
SCE Nominal Rate	$ 0.305	$ 0.305	$ 0.344	$ 0.365	$ 0.385
SDG&E Nominal Rate	$ 0.404	$ 0.404	$ 0.432	$ 0.462	$ 0.494

The average annual percentage change in forecasted year-end 2027 bundled residential rates over actual year-end 2023 rates for each IOU are shown below.

- PG&E: about 43 percent through 2027 for an average annual increase of 10.8 percent
- SCE: about 26 percent through 2027 for an average annual increase of 6.5 percent
- SDG&E: about 22 percent through 2027 for an average annual increase of 5.6 percent

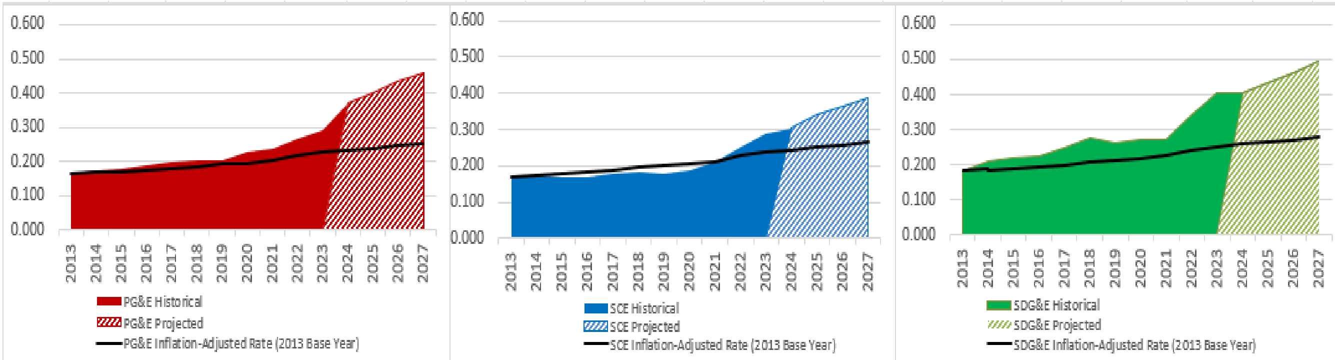
Combining the forecasted rates data in Table 11 with the historical rates data represented in Figures 13 – 15, historical and forecasted rate trends are shown in Figure 25.

[207] Current CRTs are for first quarter 2024 (Q1-2024) with current rates effective March 1, 2024 for all IOUs. Rates include the California Climate Credit (CCC) which functions as a revenue requirement reduction. PG&E and SDG&E CRT sales forecasts held at currently authorized sales forecasts; SCE CRT sales forecasts are estimated 2024-2027 sales forecasts.

[208] Projected rates do not reflect rate design changes resulting from the Flat Rate Decision (D).24-05-028. Under current rate design, PG&E and SDG&E forecasted residential rates have no fixed charge; SCE has an approximately $1/month fixed charge. PG&E and SCE forecasted small commercial rates have flat fixed charge of $10/month and $14/month respectively; SDG&E's fixed charge varies depending on the customer's maximum annual demand (ranging from about $11/month to $86/month).

[209] Inflation rate 2024 base year to 2027 is 2.6 percent/year, based on Consumer Price Index (CPI), California Region, All Items, All Urban Consumers, reported by the California Department of Finance (DOF), available here (CPI Forecast Data published November 2023).

Figure 24: PG&E, SCE, and SDG&E Electric Bundled Residential Average Rates ($/kWh)



Bundled small commercial average rate forecasts for year-end 2024 – 2027 are shown in Table 12. The average annual percentage change in forecasted year-end 2027 rates over actual year-end 2023 rates for each IOU are greater than the assumed average annual rate of inflation of 2.6 percent.[210]

Table 12: PG&E, SCE, and SDG&E Forecasted Bundled Small Commercial Rates (nominal $/kWh)

Bundled Small Commercial Rate	Year-End				
	2023 Actual	2024	2025	2026	2027
PG&E Nominal Rate	$ 0.364	$ 0.436	$ 0.470	$ 0.512	$ 0.544
SCE Nominal Rate	$ 0.290	$ 0.283	$ 0.317	$ 0.335	$ 0.349
SDG&E Nominal Rate	$ 0.402	$ 0.404	$ 0.424	$ 0.460	$ 0.490

[210] Inflation rate 2024 base year to 2027 is 2.6 percent/year, based on Consumer Price Index (CPI), California Region, All Items, All Urban Consumers, reported by the California Department of Finance (DOF), available here (CPI Forecast Data published November 2023).

The average annual percentage change in forecasted year-end 2027 bundled commercial rates over actual year-end 2023 rates for each IOU are shown below.

- PG&E: about 49 percent through 2027 for an average annual increase of 12.4 percent
- SCE: about 20 percent through 2026 for an average annual increase of 5.1 percent
- SDG&E: about 22 percent through 2026 for an average annual increase of 5.5 percent

Bundled Residential Bill Forecasts

Figure 26 shows the projected monthly bill increase resulting from the Table 11 rates forecast based on: (1) the usage amounts the IOUs use in their legal bill inserts[211] for a typical customer living in a *moderate* climate zone[212] – 500 kWh per month for PG&E and SCE, and 400 kWh per month for SDG&E and (2) a usage amount for a typical customer living in a *hot* climate zone[213] — 700 kWh per month for PG&E and SCE, and 500 kWh/month for SDG&E.[214] Average[215] electricity bills for a customer living in one of these two climate zones are shown below. All projected bill increases are greater than the assumed average annual rate of inflation of 2.6 percent.[216]

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

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

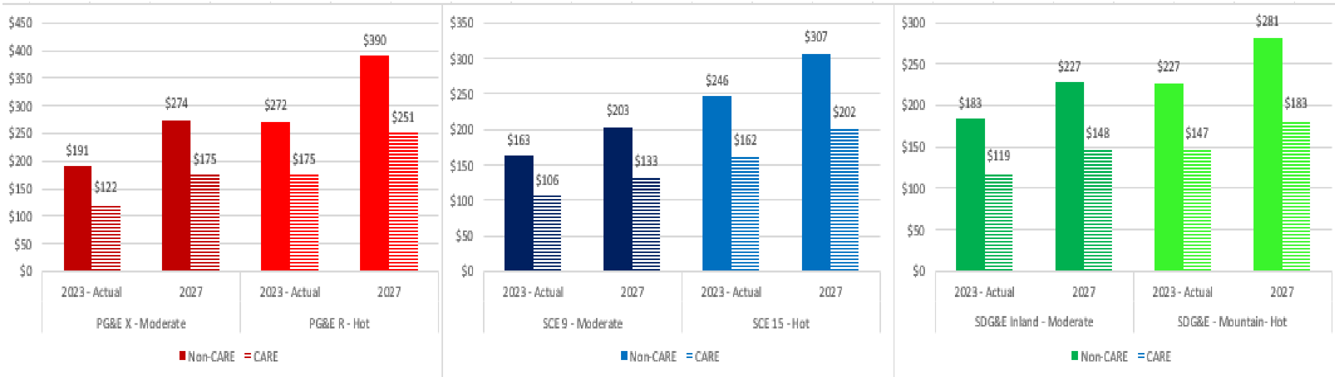
[213] Hot climate zones are as defined in D.17-09-036, Decision Adopting Findings Required Pursuant to Public Utilities Code § 745 for Implementing Residential Time-of-Use Rates. Bills for a typical customer living in a hot climate zone are calculated based on PG&E climate zone R, SCE climate zone 15,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

[214] Bills are for illustrative purposes only.

[215] Bill is averaged over the calendar year.

[216] Inflation rate 2024 base year to 2027 is 2.6 percent/year, based on Consumer Price Index (CPI), California Region, All Items, All Urban Consumers, reported by the California Department of Finance (DOF), available here (CPI Forecast Data published November 2023).

Figure 25: PG&E, SCE, and SDG&E
Current and Projected Residential Average Monthly Bills, Year-End 2023 – Year-End 2027
Typical Customer Living in a Moderate and Hot Climate Zone



Electric Bill Affordability

Affordability of utility services cannot be measured based on the magnitude of utility bills alone. Electricity and natural gas are essential services, 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, metrics that consider the costs of essential services in relation to the socioeconomic conditions of the households that are paying for those services can be useful.

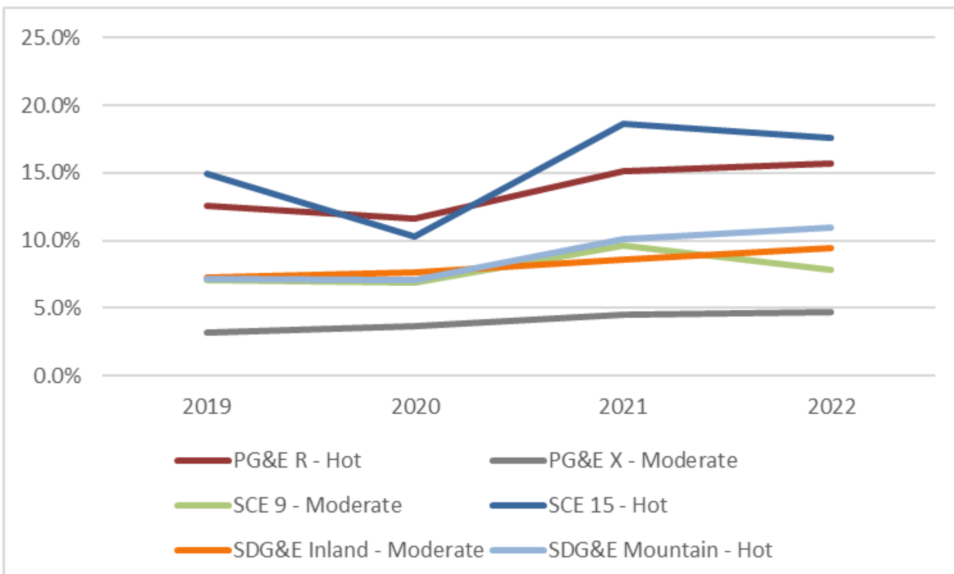
The CPUC has developed effective tools for measuring current and future affordability by geographic location. One key metric is the Affordability Ratio (AR) which quantifies the percent of a representative household's income used to pay for an essential utility service after non-discretionary expenses, such as housing and other essential utility services, are removed from the household's income. The higher an AR, the less affordable the utility service. The AR metric is sensitive to geographic variations in cost-of-living[217] and can be calculated for any of the four essential services individually (electricity, natural gas, water, and communications), or for the combined bundle of essential services. AR may also be calculated for any income level in a given area, with AR_{20} (the AR

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

for a household at the 20th percentile income level) and AR_{50} (the AR for a household at the median, or 50th percentile, of income) used as the standard representations.[218]

The AR_{20} can highlight affordability for the most potentially disadvantaged customers. The CPUC has been generating AR_{20} data since the first Affordability Report[219] was issued[220] using 2019 data, with data for 2022 published in the most recently issued Affordability Report.[221] This four-year time series provides an additional means of tracking affordability that supplements and enhances the current practice of tracking rate and bill trends by considering customer income and certain cost-of-living data not included in rate and bill data. Figure 27, below, shows the electricity service AR_{20} time series data for each IOU for the moderate and hot climate zones represented in Figure 26, above.[222]

Figure 26: PG&E, SCE, and SDG&E Electric AR20
Selected Moderate and Hot Climate Zones



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

[219] *See* D.20-07-032 in the Affordability Rulemaking proceeding in which it is ordered that the affordability metrics be used to generate an annual Affordability Report.

[220] The 2019 Affordability Report was issued in April 2021.

[221] The 2021 and 2022 Affordability Report was issued in October 2023.

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

VI. NATURAL GAS COST AND RATE TRENDS

Overview

The CPUC regulates the natural gas utility services of nearly 11.5 million customer accounts served by Pacific Gas & Electric (PG&E), Southern California Gas Company (SoCalGas), San Diego Gas & Electric (SDG&E), and several smaller utilities.[223, 224] 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[225] 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;[226]
5. Determine the feasibility of minimizing or eliminating use of SoCalGas's Aliso Canyon gas storage facility while still preserving energy reliability;[227] and
6. Create a path to transition away from fossil gas while maintaining safety, reliability, and just and reasonable rates.

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

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

[223] 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.

[224] According to the 2022 California Gas Report, SoCalGas had 5.874 million customers, PG&E 4.5 million, and San Diego 0.9 million. According to its 2022 Annual Report, Southwest Gas has over .2 million customers in California.

[225] 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.

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

[227] 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 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 to reflect changes in the market price.[228] The other two components of natural gas utility costs are typically addressed in GRCs and other cost recovery proceedings. These proceedings have several objectives, among them: setting rates as low as possible while yielding revenues that cover the utilities' costs; maintaining safe and reliable service; and promoting energy conservation and greenhouse gas (GHG) reduction.

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") covers the day-to-day operating costs of running the utility system, administrative and general expenses, depreciation of capital investments in facilities and assets over their useful lives, taxes, and a rate of return on invested capital. Utilities recover expenses (e.g., repairs, maintenance, inspections, etc.), on a dollar-for-dollar basis. They recover capital expenditures (e.g., plant, equipment, tools, etc.) through depreciation plus a rate of return on these investments.

Bundled[229] gas rates are impacted by the following: 1) changes to revenue requirement, which are mostly determined in GRCs, 2) changes to forecasted sales demand, which are determined in cost allocation proceedings, and 3) core procurement costs adjusted monthly through advice letters filed by the IOUs. The rates paid by individual customers are also impacted by how the revenue requirement is allocated among customer classes in the cost allocation proceedings.[230] Gas revenue requirements and rates can also be affected by non-GRC proceedings, such as advice letters filings dealing with leak abatement and proceedings dealing with biomethane and renewable gas projects, cost of capital, and gas distribution, transmission and storage integrity management programs.

The decisions of other state and federal agencies are often focused on safety but can also impact rates. The California Geologic Energy Management Division's (CalGEM's) 2018 changes to gas storage regulations increased the cost of maintaining gas storage facilities, and regulations enacted by the federal Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) in 2019 will increase the cost of operating and maintaining transmission pipelines. Rates

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

[229] Bundled rates are defined as rates that reflect full service from the utility which includes delivery of natural gas and the gas commodity.

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

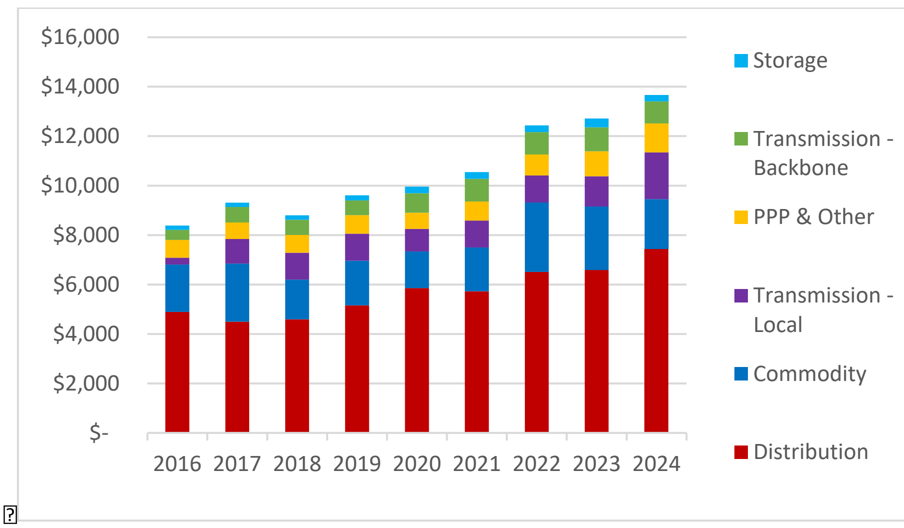
also include the cost of an increasing percentage of the GHG emissions compliance costs resulting from gas consumption, per the California Greenhouse Gas Cap and Trade Program implemented by the California Air Resources Board. 2024 Cap-and Trade compliance costs ranged from 15 to 19 cents per therm. Cap-and-Trade revenues are also returned directly to residential ratepayers outside of rates through the annual April natural gas California Climate Credit. In April 2024, just over $1 Billion in Cap-and-Trade auction revenues were returned to customers as direct on-bill automatic California Climate Credits.

Changes to Utilities' Revenue Requirements

Overview

Figure 28 below illustrates the major Gas IOUs' combined yearly revenue requirements dating back to 2016; the revenue requirements are categorized by gas cost component.

Figure 27: SoCalGas, PG&E, and SDG&E Combined Gas Revenue Requirement by Rate Component Category (January 1, $ millions)



The sections below examine the changes to each utility's revenue requirement between 2016 and 2024.[231] They are broken down to show changes for different components of the utilities' gas delivery systems as well as commodity and PPP costs. Broadly speaking, the gas system includes backbone transmission, local transmission, distribution, and storage. The utilities' backbone transmission system consists of large diameter, high pressure pipelines that connect to the interstate pipeline system, bringing gas from receipt points at the California border to the local transmission and distribution system. Local transmission pipelines transport gas from the backbone system and

[231] The source of these data is the utilities' January 19, 2024, response to the Energy Division's data requests. The core procurement revenue is based on annualized estimates; all other revenues are based on authorized revenue requirements.

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 2022, there were 10,884 miles of intrastate transmission pipeline and 204,579 miles of natural gas distribution pipelines in California.[232] Large noncore customers often take gas directly from transmission pipelines.[233] For example, PG&E indicates in A.21-09-018 that about 600 large volume noncore customers, which account for about 93 percent of noncore throughput, receive their gas directly from the backbone or local transmission systems. In accordance with the regulatory principle of cost causation in which the beneficiary pays, such customers are not allocated costs for the distribution system. Thus, distribution costs are borne primarily by core customers.

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

In the sections below, recent revenue requirement trends for the following categories are included for each utility: commodity,[234] backbone transmission, local transmission, distribution, storage, and PPP and other costs. Commodity revenues cover the costs incurred by the utilities on procurement activities undertaken on behalf of core gas customers and include gas commodity costs, net hedging costs, and brokerage fees. Backbone transmission revenues include depreciated capital expenditures, 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)[235] and state mandated PSEP costs. Local transmission revenues include depreciated capital expenditures, O&M, and A&G costs recovered for local transmission pipelines, including TIMP and PSEP costs.[236] Distribution revenues cover costs related to service lines, regulators, meters, meter reading, and billing as well as the costs for maintaining and operating high and medium pressure distribution pipelines, which include the cost associated with the

[232] PHMSA Miles and Facilities 2010+, California: Oracle BI Interactive Dashboards - Public Reports (dot.gov): https://portal.phmsa.dot.gov/analytics/saw.dll?Portalpages&PortalPath=%2Fshared%2FPDM%20Public%20Website%2F_portal%2FPublic%20Reports&Page=Infrastructure.
[233] Noncore customers consume about 65 percent of the natural gas delivered by California's natural gas utilities.
[234] The commodity revenue requirement consists of annualized net commodity costs.
[235] 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.
[236] Local transmission pipelines transport gas from backbone pipelines and storage fields to the distribution system.

Distribution Integrity Management Program (DIMP).[237] Storage costs include depreciated capital expenditures and O&M costs of operating natural gas storage facilities, including biennial well testing in accordance with CalGEM regulations and other aspects of the utilities' Storage Integrity Management Program (SIMP).[238] The PPP and "Other" costs include the costs for the California Alternate Rates for Energy (CARE) program, energy efficiency (EE) and low-income EE, and the gas public interest research and development program, which is administered by the California Energy Commission (CEC).

PG&E Revenue Requirement by Rate Category

PG&E's 2024 total gas operations revenue requirement consists of a distribution component (which accounts for 46 percent of the total gas operations revenue requirement), a local transmission component (27 percent), a commodity component (12 percent),[239] and a backbone transmission component (6 percent).[240] The PPP component accounts for approximately 9 percent of the total gas operations revenue requirement.

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

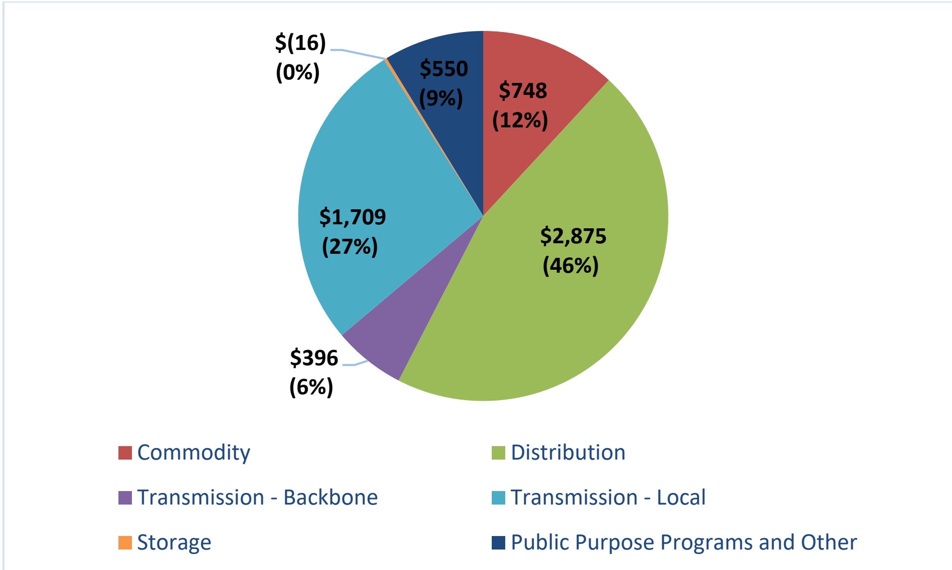
[237] The DIMP program helps identify threats to the system's distribution pipeline integrity, ranks the relative risk of each threat, implements regulations over and above regulatory minimum requirements, if justified by the degree of risk. The DIMP program also tracks performance measures to determine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

[238] 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.

[239] The commodity component's percentage of total revenue requirement can vary significantly from year to year due to changes in the market price for gas as well as changed to the overall revenue requirement. For example, it dropped from 20 percent of the total revenue requirement last year to 12 percent this year. The forecasted decrease in the weighted average cost of gas PG&E will purchase for core customers in 2024 is reflected in the lower percentage.

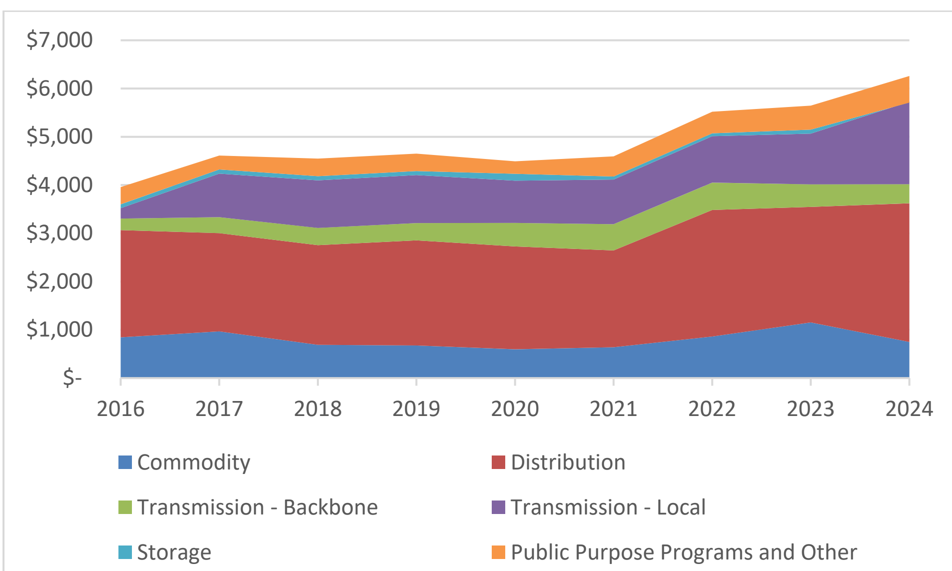
[240] PG&E reported that its storage facilities had a net negative ($16M) impact on the total 2024 revenue requirement due the forecasted decrease in work related to McDonald Island.

Figure 28: PG&E 2024 Revenue Requirement ($ millions)



PG&E's 2024 total gas operations revenue requirement has increased by approximately 58 percent since 2016, largely as a result of funding work necessary to keep its gas infrastructure operating reliably and the need to comply with state and federal pipeline safety regulations. From 2023 to 2024, PG&E's total gas operations revenue requirement increased by 10.9 percent. See Figure 30.

Figure 29: 2016–2024 PG&E January 1 Revenue Requirement by Rate Category ($ millions)[241]



[241] Data is from IOU responses to Energy Division SB 695 Report data requests, submitted to CPUC on January 19, 2024.

The underlying gas operations revenue requirement components changed by the following percentages from 2023 to 2024: [242]

- Commodity: -35.2 percent
- Backbone transmission: -15.4 percent
- Local transmission: +62.4 percent
- Distribution: +20.1 percent
- Public Purpose Programs and other: +10.9 percent[243]
- Storage: -120 percent[244]

In 2024, PG&E projects an increase to its total gas operations revenue requirement relative to 2023 due to the following drivers. First, the implementation of the 2023 General Rate Case (GRC) Decision (D.23-11-069)—which adopted gas operations revenues that cover O&M expenses, depreciated capital costs, taxes, and a rate of return on invested capital—was incorporated into rates on January 1, 2024. Second, the 2024 gas operations revenue requirement includes the 2023 under-collection, which will be collected over 24 months, beginning on January 1, 2024.[245] Third, the gas operations revenue requirement includes separately funded programs such as Wildfire Mitigation and Catastrophic Events. Fourth, year-end balances from various regulatory accounts[246] are included in the 2024 gas operations revenue requirement.

PG&E reports a 35.2 percent decrease to its commodity related revenue requirement component, which reflects the forecasted decrease in the weighted average cost of gas PG&E will purchase for core customers in 2024.

The year-over-year 15.4 percent decrease to the backbone transmission revenue requirement component is driven by a forecasted decrease in backbone transmission pipeline integrity work. The backbone transmission system (BTS) is used to transport gas from PG&E's interconnection with interstate pipelines, other local distribution companies, and California gas fields to PG&E's local transmission and distribution system.

[242] Data is from IOU responses to Energy Division SB 695 Report data requests, submitted to CPUC on January 19, 2024. The dollar value associated with each underlying gas revenue requirement component changes yearly; the rate at which these components change (presented in the bullets as percentages) should not be added or expected to total 100%.
[243] 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.
[244] PG&E reported that its storage facilities had a net negative ($16M) impact on the total 2024 revenue requirement due the forecasted decrease in work related to McDonald Island.
[245] The revenue requirement adopted in D.23-11-069 was not reflected in the January 2023 revenues.
[246] Include regulatory accounts such as the Core and Noncore Fixed Cost Accounts, Risk Transfer Balancing Account (RTBA), and Residential Uncollectibles Balancing Account.

PG&E's local transmission revenue requirement component will increase by 62.4 percent due to the implementation of D.23-11-069, which adopted an increase in backbone transmission pipeline integrity work such as inspections, assessments, and strength testing. The local transmission system consists of the pipelines that accept gas from the BTS and transport it to the distribution system.

The primary drivers of the 20.1 percent increase in the distribution revenue requirement component are the funds adopted for PG&E's Gas Service Customer Response, Leak Management and Corrosion Control, and the 2023 under-collection that will be collected over 24 months starting on January 1, 2024, adopted in D.23-11-069.

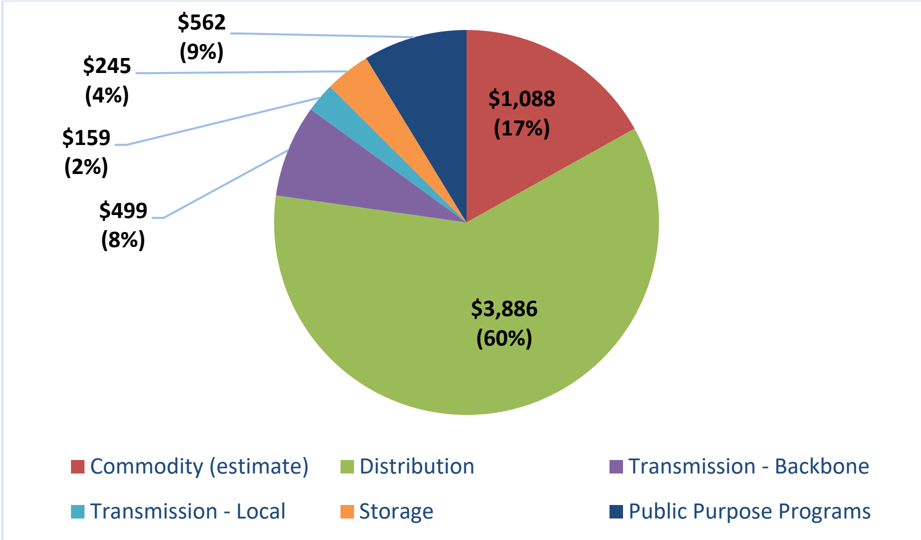
The main driver of the 120 percent decrease to PG&E's storage revenue requirement is the decrease in planned work related to McDonald Island Natural Gas Storage Facility. Storage services include customer gas storage, carrying cost of working gas in storage for core customers, and unbundled storage.

The drivers of the 10.5 percent increase to the Public Purpose Programs (PPP) revenue requirement component are increases in greenhouse gas costs and Energy Efficiency costs. PPP revenues fund the CARE discount collected from non-CARE customers, the Energy Efficiency program costs, the gas CPUC Fee, and the Natural Gas Greenhouse Gas Costs and Credit.

SoCalGas Revenue Requirement by Rate Category

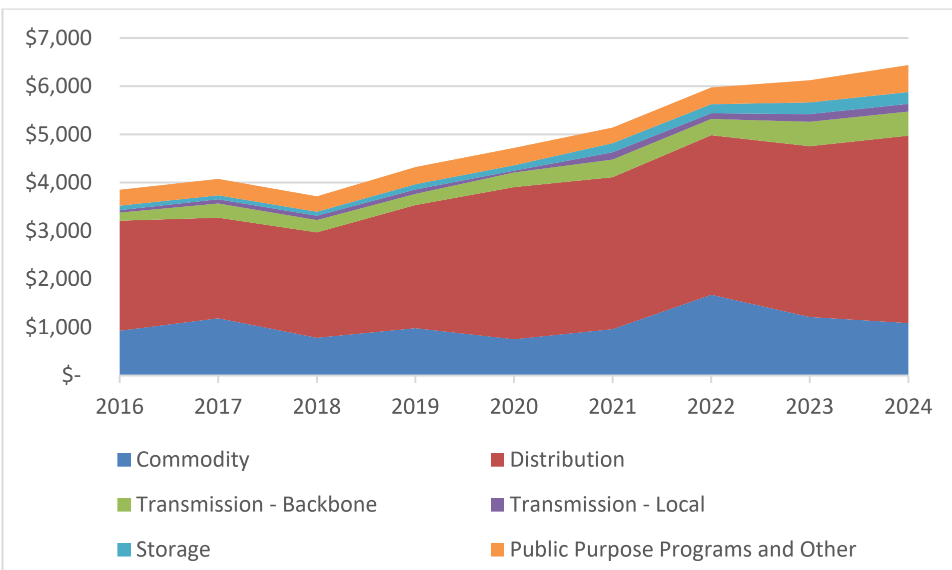
SoCalGas' 2024 total revenue requirement consists of a distribution component (which accounts for 60 percent of the total revenue requirement), a commodity component (17 percent), a backbone transmission component (8 percent), a storage component (4 percent), and a local transmission component (2 percent). The PPP component accounts for 9 percent of the total gas operation revenue requirement.

Figure 30: SoCalGas 2024 Gas Revenue Requirement ($ millions)



Since 2016, SoCalGas' total revenue requirement has increased by 67.2 percent. From 2023 to 2024, SoCalGas' total revenue requirement has increased by 5.2 percent. See Figure 32.

Figure 31: 2016–2024 SoCalGas January 1 Gas Revenue Requirement by Rate Category ($ millions) [247]



[247] Data is from IOU responses to Energy Division SB 695 Report data requests, submitted to CPUC on January 19, 2024.

SoCalGas's revenue requirement components changed by the following percentages from 2023 to 2024:

- Commodity: - 10.3 percent
- Backbone transmission: - 1.6 percent
- Local transmission: + 1.3 percent
- Distribution: + 9.7 percent
- Storage: + 0 percent
- Public purpose programs and other: + 22.2 percent

SoCalGas projects a total revenue requirement increase in 2024 relative to 2023 due to the following drivers. First, SoCalGas' revenue requirement increased due to an increase in the Cost of Capital Mechanism Adjustments and higher costs recorded in regulatory balancing account. Second, the Public Purpose Programs[248] (PPP) revenue requirement increased to fund CARE subsidies, under-collections, Energy Savings Assistance programs, Energy Efficiency programs, and Research and Development.

SoCalGas' procurement department projects a 10.3 percent year-over-year decrease to its commodity-related revenue requirement component due to a decrease in the forecasted weighted average cost of gas it will purchase on behalf of core customers in 2024.

SoCalGas' backbone transmission revenue requirement component will decrease by 1.6 percent in 2024 because the Backbone Transmission Balancing Account decreased by $26.7 million.[249] SoCalGas' pipelines are classified by SoCalGas/SDG&E as backbone transmission if they receive gas from receipt points mainly along the California-Arizona border and transport it to SoCalGas' storage fields and local transmission system.

SoCalGas' local transmission revenue requirement component increased by 1.3 percent due to an increase in PSEP regulatory account balances. Local transmission pipelines transport gas from backbone pipelines and storage fields to the SoCalGas' distribution system.

SoCalGas' distribution revenue requirement component increased by 9.7 percent due to higher overall operational costs, higher balancing balances, and Greenhouse Gas costs. SoCalGas' distribution revenue requirement covers customer-related meter and billing costs, medium and high pressure distribution pipelines costs, and costs related to balancing accounts.

[248] *See* SoCalGas Advice Letter 6216-G.

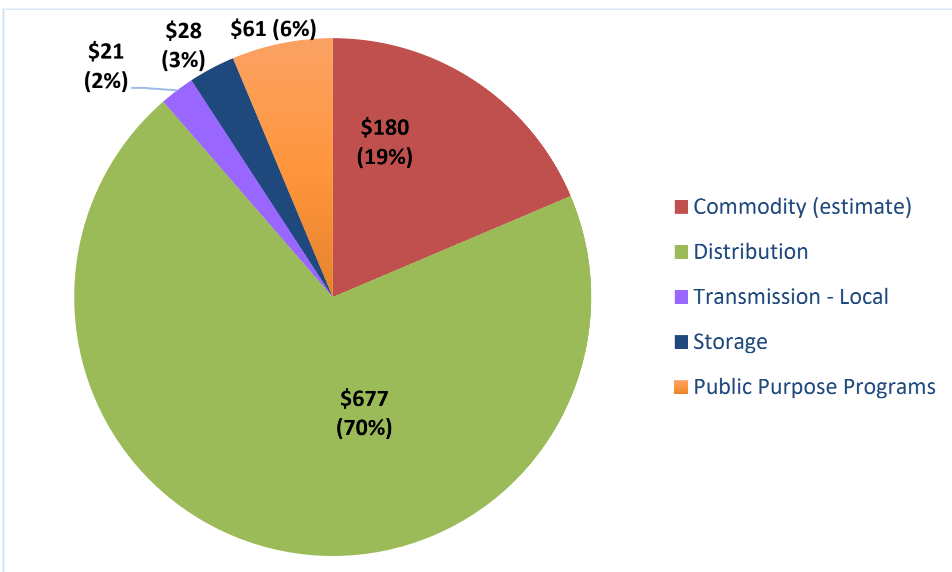
SoCalGas' storage-related revenue requirement component remained unchanged in 2024 relative to 2023. SoCalGas' natural gas storage facilities include gas wells, compressors, pipelines and various buildings and ancillary equipment.

SoCalGas' PPP revenue requirement component increased by 22.2 percent in 2024 due to cost increases in the Energy Savings Assistance and CARE programs.[250] The PPP revenue requirements component funds the CARE discount collected from non-CARE customers, Energy Efficiency program costs, the gas CPUC Fee, and the Natural Gas Greenhouse Gas Costs and Credit.

SDG&E Revenue Requirement by Rate Category

SDG&E's 2024 total gas operations revenue requirement consist of a distribution component (which accounts for 70 percent of the total gas operations revenue requirement), a commodity component (19 percent), a storage component (3 percent), and a local transmission component (2 percent). SDG&E's backbone transmission revenue requirement is recovered in SDG&E's core procurement rate.[251] The PPP component accounts for 6 percent of the total gas operation revenue requirement.

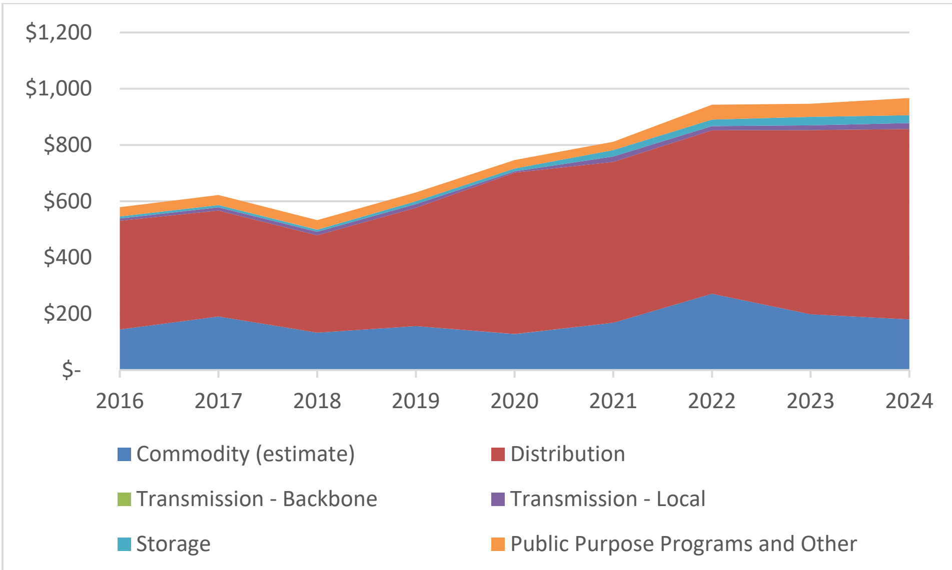
Figure 32: SDG&E 2024 Gas Revenue Requirement ($ millions)



[251] SoCalGas' procurement department purchases gas on behalf of SDG&E's core customers. A Backbone Transmission Surcharge is included in SDG&E's core procurement rate which pays for the Backbone Transmission costs assigned to SDG&E's core customers.

SDG&E's total gas operations revenue requirement has increased by approximately 67 percent since 2016, with a 2 percent net increase from 2023 to 2024. See Figure 34.

Figure 33: 2016–2024 SDG&E January 1 Gas Revenue Requirement by Rate Category ($ millions)



SDG&E's revenue requirement components[252] changed by the following percentages from 2023 to 2024:

- Commodity: - 9.1 percent,
- Local transmission: +23.5 percent,
- Distribution: +3.4 percent,
- Storage: - 6.7 percent, and
- Public Purpose Programs and other: + 29.8 percent.

SDG&E's 2024 total gas operations revenue requirement increased due to the following drivers. First, SDG&E's transportation revenue requirement increased by $37.8 million due to allocated costs from SoCalGas' regulatory account balances.[253] Second, SDG&E' GHG revenue requirements increase by $23 million.[254] Third, the total 2024 PPP revenue requirement increased by $13.7 million. SDG&E's gas operations revenue requirement will be offset by the lower revenue requirement forecasts associated with commodity purchases, storage, and SDG&E regulatory account balances.

[252] SDG&E's backbone transmission revenue requirement is recovered through SDG&E's procurement rate.
[253] SoCalGas Advice Letter 6210.
[254] SDG&E Advice Letter 3247-G-B.

SDG&E projects a 9.1 percent year-over-year decrease to its commodity-related revenue requirement component due to a decrease in the forecasted weighted average cost of gas that will be purchased on behalf of core customers in 2024.

SDG&E's local transmission revenue requirement component increased by 23.5 percent due to higher PSEP regulatory balancing accounts. Local transmission revenue requirements recover the costs of transporting gas from SoCalGas' backbone pipelines and storage fields to the SDG&E distribution system. Local transmission revenue requirements also recover the costs associated with the Transmission Integrity Management Program (TIMP) and the Pipeline Safety Enhancement Plan (PSEP).

SDG&E's distribution revenue requirement component increased by 3.4 percent due to an increase in the Cost of Capital Mechanism Adjustments, higher transportation costs, increases in the Residential Uncollectible Balancing Account (RUBA), PSEP Distribution regulatory balancing accounts, and higher Greenhouse Gas (GHG) costs. SDG&E's distribution revenue requirement component recovers the cost of operating high-pressure and medium-pressure distribution pipelines as well as the costs associated with metering and billing services.

SDG&E's PPP revenue requirement component increased by 28.9 percent in 2024[255] relative to 2023.[256] Public Purpose Program revenue requirements cover the costs associated with public assistance programs. The primary 2024 PPP year-over-year revenue requirement drivers were increases in funding for the RD&D program ($19.8 million) and the CARE program ($6.6 million). These revenue requirement increases were offset by a decrease in EE program and ESA program funding.

Public Purpose Programs (PPP)	2023 Totals ($000)	2024 Totals ($000)	Difference ($000)	Difference (%)
California Alternate Rates for Energy (CARE)	$ 22,557	$ 29,154	$ 6,597	29.2%
Energy Savings Assistance (ESA) programs	$ 10,316	$ 7,006	$ (3,310)	-32.1%
Energy Efficiency (EE)	$ 9,991	$ 164	$ (9,827)	-98.4%
Research, Development and Demonstration (RD&D) programs	$ 2,279	$ 22,032	$ 19,753	866.7%
School Energy Efficiency Stimulus Program (SEESP)	$ 2,098	$ 2,184	$ 86	4.1%
California Department of Tax and Fee Administration (CDTFA)	$ 55	$ 400	$ 345	627.3%
Port Energy Management Plan Balancing Account	0	$ 47	$ 47	
Total PPP Revenue Requirement	**$ 47,296**	**$ 60,987**	**$ 13,691**	**28.9%**

Average Rates by Customer Class

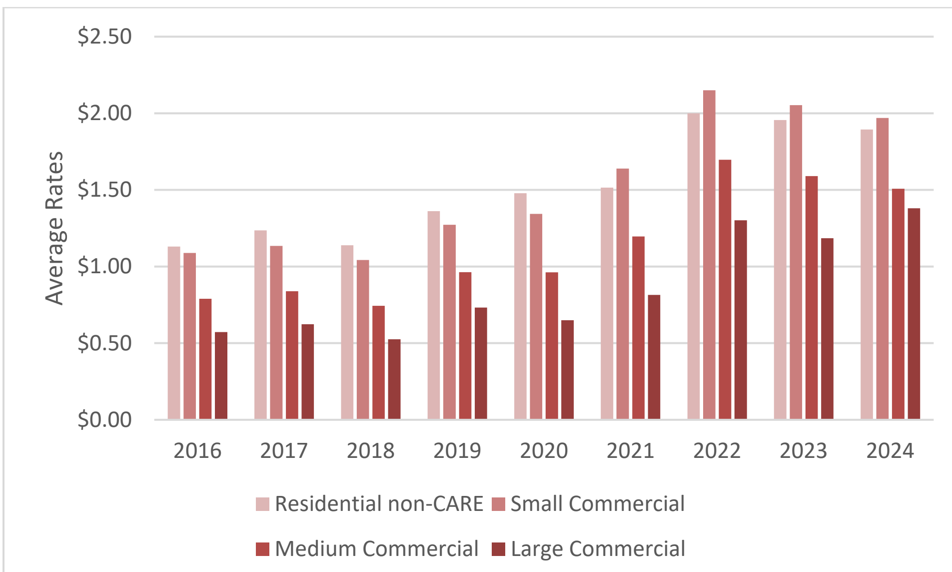
At a high level, gas customers are divided between core and noncore customers. The utility purchases gas for core customers, who are made up of residential and relatively small commercial and industrial customers. Noncore customers are large commercial and industrial customers such as electric generators, hospitals, and refineries, who purchase their own gas or use a third-party to

255 Advice Letter 3245-G.
256 Advice Letter 3137-G.

purchase it for them. Noncore customers pay the utility to transport their gas and often take gas directly off the backbone transmission system, bypassing the need to pay for the costs of the distribution system.

These two large categories are further subdivided into smaller groups with varying rates. A breakdown of average rates by core customer class is shown for SoCalGas, SDG&E, and PG&E in Figures 35–37. Each class shows an upward trend during this period (2016 to 2024). Core customers pay higher rates than noncore customers because they are more expensive to serve, require greater reliability, and take gas off the distribution system.[257] The fixed costs of serving larger customers are recovered over a larger number of therms, due to their higher usage, which results in lower transportation rates per therm. The bundled average rates for core customers include a customer or minimum charge,[258] procurement, transportation, and the PPP surcharge. CARE residential customers receive a 20 percent discount off the entire natural gas bill.

Figure 34: SoCalGas Gas Average Rates per Therm by Class in Effect January 1 (2016-2024)



[257] Noncore 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).
[258] For residential customers, SoCalGas imposes a $5 fixed Non-CARE monthly charge and a $4 fixed CARE month charge; SDG&E applies a $4 minimum Non-CARE transportation charge and a $3.20 minimum CARE transportation charge; PG&E imposes a $4 minimum transportation charge applicable to Non-CARE customers only.

Figure 35: SDG&E Gas Average Rates per Therm by Class in Effect January 1 (2016-2024)

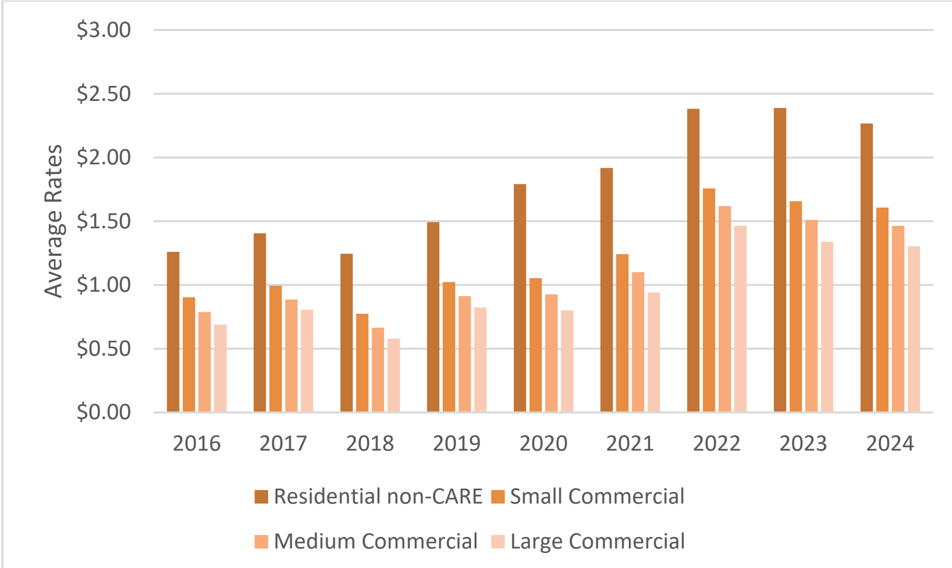
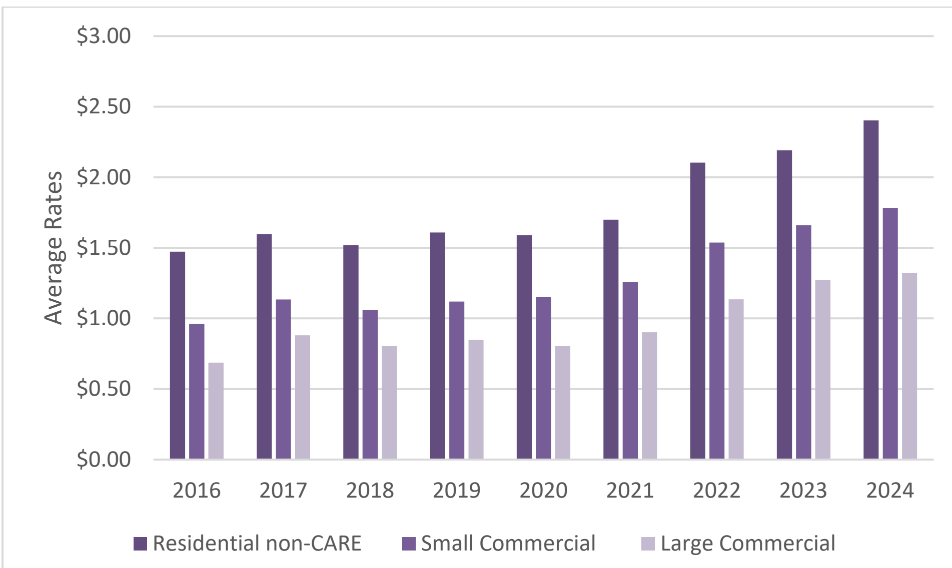


Figure 36: PG&E Gas Average Rates per Therm by Class in Effect January 1 (2016-2024)



Costs and Rates Containment

The CPUC has undertaken actions in the preceding 12 months (May 1, 2023, to April 30, 2024) and is taking actions in the succeeding 12 months (May 1, 2024, to April 30, 2025) 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

2023 General Rate Case (GRC) Review

PG&E filed its first combined GRC/Gas Transmission & Storage (GT&S) Application (A.) 21-06-021) on June 30, 2021, requesting cost recovery and rate approvals for 2023 through 2026. PG&E's 2023 GRC combined gas operations revenue requirement amount request was: $4.706 billion, $5.220 billion, $5.643 billion, and $6.099 billion for 2023, 2024, 2025 and 2026, respectively.[259] These amounts represented increases of 15 percent, 28 percent, 38 percent and 49 percent in 2023, 2024, 2025 and 2026, respectively, relative to PG&E's 2022 adopted gas revenues. The costs and revenue requests presented in the 2023 GRC went through the CPUC's regulatory due diligence process, with some being challenged by intervenors. On November 16, 2023, Decision (D.)23-11-069 adopted PG&E Test Year 2023 GRC, resulting in a $413 million (8.78 percent) reduction to PG&E's Test Year 2023 gas operation revenue requirement request; a $577 million (11.05 percent) reduction in 2024; $761 million (13.49 percent) reduction in 2025, and a $948 million (15.54 percent) reduction in 2026.[260]

PG&E's 2023 GRC Request ($ Millions)				
Year	2023	2024	2025	2026
Gas Distribution	$ 2,864	$ 3,092	$ 3,370	$ 3,659
GT&S	$ 1,842	$ 2,128	$ 2,273	$ 2,440
Total	$ 4,706	$ 5,220	$ 5,643	$ 6,099

CPUC's 2023 PG&E GRC Decision (D.)23-11-069 ($ Millions)				
Year	2023	2024	2025	2026
Gas Distribution	$ 2,588	$ 2,695	$ 2,837	$ 3,004
GT&S	$ 1,705	$ 1,948	$ 2,045	$ 2,147
Total	$ 4,293	$ 4,643	$ 4,882	$ 5,151

Request v. Decision Percentage Difference				
Year	2023	2024	2025	2026
Gas Distribution	-9.64%	-12.84%	-15.82%	-17.90%
GT&S	-7.44%	-8.46%	-10.03%	-12.01%
Total	-8.78%	-11.05%	-13.49%	-15.54%

Gas Cost Allocation and Rate Design (CARD)

The CARD proceeding is the second phase of a GRC where costs adopted in the GRC proceeding are allocated among the various customer classes and determine their respective rates.

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, however, were

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

[260] *See* D.23-11-069 Appendix A See Table 1, A and D.23-11-069 page 3-4.

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 topics for transmission and the unbundled gas marketplace, including storage.

On September 30, 2021, PG&E filed its 2023 GT&S Cost Allocation and Rate Design (CARD) Application. It addressed PG&E's gas marketplace and sales forecasting for unbundled services for the years 2023-2026. The Application requested the Commission approve PG&E's proposed cost allocation and gas rate design which would incorporate the GT&S revenue requirements and capacity forecasts from the decision in PG&E's GRC Application.

The CARD Application contained direct testimony on the issues of electric generation and non-electrical generation throughput, backbone rate inputs, local transmission core versus noncore cost allocation, general cost allocation and rate design, storage cost allocation and rate design, core gas supply portfolio, and natural gas vehicle tariff enhancements.

On June 30, 2023, PG&E filed a Motion For Adoption of All-Party Settlement and Stipulation (Settlement Motion). The All-Party Settlement resolves three broad categories of settled terms: (1) All-Customer Group Settlement (ACG Settlement), (2) Baja-Redwood Differential Settlement (Baja-Redwood Settlement), and (3) Undisputed Issues Stipulation (Stipulation).

Decision 24-03-002 of March 7, 2024, grants the Settlement Motion and adopts the All-Party Settlement without modification. Taking account of the PG&E GRC decision and other Commission approvals impacting rates, the proposed rates will be implemented to recover the GT&S revenue requirement approved in the GRC decision, D.23-11-069. Parties agree on an LT cost allocation of 65.5% for core customers and 34.5% for noncore customers, prior to the impact of forecast discounted volumes. The CARD decision covers the timeframe from January 1, 2023, to December 31, 2026.

Gas Procurement Costs Incentives

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

On July 11, 2023, PG&E submitted its CPIM performance report, which covers the period November 1, 2020, though October 31, 2021 (Year 28). The report states that PG&E's core gas costs and reservation charges were $105,054,991 below the CPIM benchmark and that, according to the mechanism, the savings should be split with $94,845,986 going to ratepayers and $10,209,005 to shareholders. The CPUC's Public Advocates Office's Monitoring and Evaluation Report for the Year 28 CPIM has not yet been released. The Public Advocates report audits and evaluates the total savings, shareholder award, and ratepayer benefits as presented in the CPIM performance report.

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

2024 GRC

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

SDG&E requests a $2.996 billion ($2.332 billion for electric and $664 million for gas) revenue requirement, to be effective January 1, 2024, an increase of $449 million or a 17.6 percent increase over the expected 2023 revenue requirement. If approved without change, this would result in an estimated bill impact of 5.3 percent for SDG&E electric residential customers and 17.5 percent for gas residential customers in 2024 compared to 2023. For PTYs 2025-2027, SDG&E is requesting additional revenue increases of $315 million (10.5 percent) in 2025, $306 million (9.2 percent) in

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

2026, and $279 million (7.7 percent) in 2027. In the GRC, party intervenors will review the costs presented and revenues requested by the utilities and challenge costs as they see fit. The CPUC will assess the merits of all the parties' positions and make its decision taking into account safety, reliability, and affordability.

Gas Cost Incentives

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

On July 11, 2023, SoCalGas submitted an application (A.23-07-005) stating that its core procurement costs for the period April 1, 2022, through March 31, 2023, (Year 29), were $417.6 million below the benchmark and seeking approval of a shareholder reward of $62.8 million for its performance. The CPUC's Public Advocates Office Monitoring and Evaluation Report for Year 29 of the GCIM is pending. This report audits and evaluates total savings, shareholder award, and ratepayer benefits as presented in the application. SoCalGas' recorded gas costs were $417.6 million below the benchmark, which, if approved with the shareholder reward, would result in core ratepayer gas commodity costs that were $354.9 million below the prevailing market price.

Cost Allocation Proceeding (CAP)

The CAP proceeding is the second phase of a GRC where costs adopted in the GRC proceeding are allocated among the various customer classes and determine their respective rates.

On September 30, 2022, Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) filed their Cost Allocation Proceeding (CAP) application to revise rates for gas services, and to implement gas storage related proposals effective January 1, 2024, through December 31, 2027. In addition, in this application, SoCalGas and SDG&E proposed to move the CAP to a four-year cycle (instead of the three-year cycle of the previous Triennial Cost Allocation Proceeding (TCAP)), to match the cycle of what is now used for the GRC.

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

A December 14, 2022, Pre-Hearing Conference addressed the scope, schedule, and other matters of the CAP. A February 2, 2023, Scoping Memo detailed the issues to be addressed and set a procedural schedule. A September 13, 2023, Ruling granted parties' request to reduce the hearing schedule from two weeks to one week given the reported progress of the settlement discussion. Joint Motions requesting the Commission accept three different Settlement Agreements were filed December 1, 2023 (the Fixed Charge Settlement), December 14, 2023 (the Hydrogen Refueling Settlement), and December 15, 2023 (the Main Settlement). A June 3, 2024, Proposed Decision (PD) was issued that, if adopted by the Commission, would approve the Main Settlement Agreement but would reject the Fixed Charge Settlement and the Hydrogen Refueling Settlement. This PD may be heard, at the earliest, at the Commission's July 11, 2024, Business Meeting.

Aliso Canyon Order Instituting Investigation

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

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

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

The staff proposal also suggests biennial reassessment of gas and electric system reliability to gauge progress and potential changes to the maximum amount of gas stored at Aliso Canyon based on the reassessment. The CPUC increased the maximum inventory level for the facility in November 2021 to protect "gas and electricity customers from reliability and economic impacts."[262] In August 2023, in light of similar considerations related to gas price spikes experienced in the winter of 2022, the CPUC further increased the maximum inventory level to match an estimate of the safe maximum inventory provided by the California Geologic Energy Management Division of the Department of Conservation.[263] That level will remain in place until the CPUC issues a new decision in the proceeding. Unlike winter 2022-23, the forward gas market and spot market in winter 2023-24 experienced lower gas prices due to mild weather, lower demand, and higher storage levels in Southern California.

The proceeding remains open. The CPUC has solicited party testimony in the proceeding, including on the staff proposal and an additional supplemental proposal, and anticipates a decision addressing these questions during 2024.

Line 1600 Repairs and Replacement

In A.15-09-013, SoCalGas and SDG&E applied for a Certificate of Public Convenience and Necessity (CPCN) for the construction of a new transmission pipeline, Line 3602. The utilities also proposed to reclassify an existing transmission pipeline, Line 1600, from transmission to distribution to avoid potential customer rate impacts due to required pressure testing. In Phase One of the proceeding, the CPUC evaluated the need for the proposed project pertaining to safety, reliability, resiliency, and operational flexibility and to resolve basic planning assumptions and standards that may inform the California Environmental Quality Act (CEQA)/National Environmental Policy Act (NEPA) process. On June 21, 2018, the CPUC denied SDG&E's and SoCalGas' request for a CPCN for the proposed Line 3602 project.[264]

The CPUC opened a second phase to review cost forecasts pertaining to the SoCalGas/SDG&E's Line 1600 PSEP.[265] 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.

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[262] See D.21-11-008, Conclusion of Law 1: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M421/K086/421086399.PDF.

[263] *See* August 2023 announcement at CPUC Takes Action to Enhance Energy Affordability For Ratepayers in Southern California .

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

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

On December 3, 2020, the CPUC denied the rehearing of D.20-02-024 with modifications. The modification rejected the Intervenor's request to consider the basis for the cost of the full hydrotest alternative during the second phase of the proceeding and states that because Design Alternative 1 is in effect as legally required, the cost of a different alternative is not relevant. Design Alternative 1 consists of replacing pipeline in high consequence areas and hydrotesting in non-high consequence areas, which the CPUC's Safety and Enforcement Division formally approved on January 15, 2019. The reasonableness of forecasts established in this phase will be reviewed in later applicable GRCs.

D.20-02-024, however, left this proceeding open to direct SoCalGas and SDG&E to file specific cost information related to forecasts, estimation methodologies, and accounting treatment. SoCalGas and SDG&E complied in timely submitting the information requested in D.20-02-024. On January 11, 2024, D.24-01-007 decided that any further cost-related issues should be handled in the SoCalGas/SDG&E's' 2028 General Rate Case and that all concerns in this proceeding had been resolved. D.24-01-007 closed the A.15-09-013 proceeding.

Angeles Link Application

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

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

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

In March 2023, SoCalGas launched a Planning Advisory Group (PAG) to solicit feedback from outside technical experts on Phase 1 issues relating to the Angeles Link project and a Community Based Organization Stakeholder Group (CBOSG) to inform and receive feedback on additional issues affecting the communities where the pipeline would be cited, including workforce planning, pipeline routing, and safety. SoCalGas held quarterly meetings with both the PAG and the CBOSG throughout 2023. Since launching Phase 1, SoCalGas presented initial analysis on the following topics related to hydrogen production and transportation: (1) water use and availability, (2) GHG emissions, (3) hydrogen leakage, and (4) NOx emissions. SoCalGas is anticipated to release a draft Demand Study in Q1 of 2024 assessing potential demand for clean renewable hydrogen in its service territory for various ends uses, including electricity generation, vehicle/vessel transportation, and industrial manufacturing.

All Investor-Owned Utilities

Long-Term Gas Planning Rulemaking

On January 16, 2020, the CPUC opened a rulemaking[266] to initiate long-term planning procedures for the California natural gas system. The goal of the proceeding is to ensure safe, reliable, and affordable gas service as fossil gas consumption declines in support of California’s climate goals. As noted above, rates are derived by dividing the revenue requirement by sales. As total gas sales decline, rates per therm will go up unless the revenue requirement also declines. Thus, cost containment in an era of declining fossil gas use requires strategic planning to reduce the revenue requirement. Increased coordination between GHG reduction activities and gas system planning will support cost containment.

Phase 1 and Phase 2 of the rulemaking have been completed and Phase 3 was initiated on February 22, 2024. Phase 1 established baseline standards and addressed issues of immediate concern. These included: determining that the existing reliability standards are still adequate; harmonizing the Operational Flow Order (OFO) penalty structure across the state; and setting a minimum in-service standard for backbone pipeline capacity and creating a citation program for utilities not meeting that standard. The OFO Decision was issued on April 22, 2022. The Decision on the remaining Track 1 issues was issued on July 14, 2022.

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

The CPUC has issued two critical decisions in Phase 2. First, the CPUC adopted Gas General Order 177 in December 2022, which requires utilities to request a Certificate of Public Convenience and Necessity and conduct California Environmental Quality Act (CEQA) analysis before building certain large gas infrastructure projects if they are not emergency projects and will affect criteria emissions. This order increases CPUC oversight of gas transmission infrastructure, bringing it in line with the CPUC's oversight of electric transmission infrastructure.

Second, in December 2023, the CPUC adopted criteria and information requirements for transmission pipeline repair or replacement projects.[267] It also adopted criteria to determine when declining demand can enable transmission lines to be safely derated or decommissioned without harming reliability. This decision also reinforced Pipeline and Hazardous Materials Safety Administration (PHMSA) definitional requirements for gas utilities and adopted a proposal from PG&E to reclassify 600 miles of transmission line as distribution in alignment with PHMSA definitions. Last, the CPUC determined that storage facilities are generally necessary for reliability and cost containment at this time, while noting that the specific case of Aliso Canyon will be decided in the Aliso Canyon Investigation.

To commence Phase 3, the CPUC issued a ruling in February 2024 introducing an interagency staff white paper on gas transition issues.[268] The white paper suggests that while a transition away from fossil gas is necessary to meet the state's decarbonization goals, there are risks that must be anticipated and balanced through the CPUC's authority and through strategic interagency coordination. Phase 3 of this rulemaking will focus on identifying short-, medium-, and long-term actions to manage the state's transition away from fossil gas in support of protecting customers and the environment and assuring access to safe, reliable, and affordable energy service.

High Gas and Electric Prices Investigation

The CPUC held a public En Banc on February 7, 2023, to gather facts on the extent of, and reasons for, high gas prices during winter 2022-23. The CPUC gathered critical data during the En Banc, including the following:

- Gas prices for delivery on December 22, 2022, were nearly seven times higher compared to the same day in 2021.
- The price spikes were not unique to California and were experienced in other Western gas markets as well, including in Nevada and Arizona.
- California gas utilities had to rely heavily on storage inventory to meet the increased heating demand brought on by cold weather early in the winter season.

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[267] *See* https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M521/K892/521892086.PDF.

[268] *2024 Joint Agency Staff Paper: Progress Towards a Gas Transition. See* https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M526/K067/526067752.PDF.

- High gas costs led to high electric prices in the CAISO Market and the Western Energy Imbalance Market compared to 2021-2022. CAISO estimated that electricity prices were $3 billion over the norm in December 2022.

The CPUC opened an Order Instituting Investigation (OII) on March 16, 2023, to continue fact-gathering efforts on the causes of the extraordinarily high gas prices; to investigate whether the utilities' communications were sufficient; and to explore potential solutions to avoid similar events in the future and minimize their impacts if they do occur. The CPUC held a workshop in October 2023 to discuss gas utility and independent storage provider preparedness for winter 2023-24, including lessons learned from the previous winter's price spikes and utility communication plans should similar price spike events occur. Some takeaways from the workshop include that better supply and demand equilibrium was forecasted for winter 2023-24 due to expected milder weather and higher storage inventories.[269] The proceeding is ongoing.

Dairy Biomethane Pilot Projects

Pursuant to SB 1383 (Lara, 2016), the CPUC opened a rulemaking[270] to establish dairy biomethane natural gas pipeline injection demonstration projects. In 2018, the CPUC along with the Air Resources Board and the Department of Food and Agriculture, put forth a pilot solicitation and selected six projects for construction. Contracts between utilities and developers of the six pilot projects were signed, and the new dairy biomethane facilities started converting biogas from dairy digesters into renewable natural gas (RNG) for heating and transportation purposes in an effort to move California closer to its goal of reducing methane emissions by 40 percent below 2013 levels by 2030. The pilots will undergo evaluation processes to determine GHG reduction levels and project goal attainment. Forecasted costs associated with the six pilot projects are estimated to be approximately $133 million, and utilities are required to seek prior authorization from the CPUC for any deviation from the original cost estimates. Due to delays experienced as a result of the COVID-19 pandemic, the first of these projects was adjusted to come online in 2021 and the last of these projects was anticipated to come online in the third quarter of 2023. As of February 2024, only one of the six projects – JG Weststeyn – was not yet online. As of February 2024, JG Weststeyn is working with the CPUC to transfer the dairy pilot ownership to Maas Energy Works for eventual operation.

Notably, PG&E initiated A.23-04-005 in April of 2023 to consider approval of cost overruns specific to the Merced CEE project. A decision in that proceeding is anticipated sometime in 2024. Similar cost overruns were reported separately by SoCalGas in the pending Sempra GRC for the (1) CalBioGas Buttonwillow LLC, (2) CalBioGas North Visalia LLC, (3) CalBioGas South Tulare LLC, and (4) Lakeside Pipeline LLC dairy pilot projects, which the CPUC has not yet determined whether to approve.

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[269] *See* Workshop Report: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M526/K147/526147574.PDF.

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

Biomethane Procurement Considerations (SB 1440 Implementation)

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

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

The Commission issued a ruling on July 20, 2023, requesting estimated program procurement costs and proposed program cost caps from the gas IOUs to help determine potential program impacts and enhance ratepayer protections. A ruling seeking party input into possible program modifications to increase market competition and lower procurement costs for ratepayers is expected in Q2 2024, followed by a proposed decision recommending adoption of some version of the procurement plans before the end of 2024. In the meantime, procurement solicitations from all of the large gas IOUs are ongoing, as directed by D.22-02-025.[271]

Renewable Hydrogen Injection Safety Pilot Projects

In December 2022, the CPUC issued D.22-12-057 ordering the gas IOUs to propose pilot projects studying the safety and operational impacts of blending hydrogen into the methane pipeline system to help inform what a system-wide safe hydrogen injection standard might look like. The decision requires California's large gas IOUs to either amend an existing application or file a new application with proposals to pilot projects that inject blends of "clean renewable hydrogen" at levels ranging from 0.1 to 20 percent of the gas injected into designated portions of each gas IOU's pipeline

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

system. "Clean renewable hydrogen" is defined by D.22-12-057 as emitting no more than 4 kilograms (kg) of carbon dioxide equivalent (CO2e) per 1 kg of hydrogen produced on a life-cycle basis and not using fossil fuel as a feedstock or production energy source. That definition conforms with the definition for "clean hydrogen" eligible for federal production tax incentives, as established in the Inflation Reduction Act of 2022 while adding a "renewable" standard that is ultimately contingent on further deliberation through the SB 1075 (Skinner, 2022) implementation process in collaboration with CARB and the CEC.

The Scoping Ruling for A.22-09-006 issued March 3, 2023, gave the gas IOUs – including PG&E, which was not previously part of the application filing – a year to submit revised proposals that comport with the requirements of D.22-12-057.

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

In November 2021, CPUC's Energy Division staff released a report recommending the complete elimination of all gas line extension subsidies (i.e., allowances, refunds, and discounts) for all customer classes effective July 1, 2023. According to the staff report, gas ratepayers subsidized gas line extensions at a cost of $144,349,622 in 2020, all of which would become annual gas ratepayer savings if those line extension subsidies were to be eliminated and gas-based construction stayed at 2020 levels.[272] The report further stated, "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."[273] The CPUC issued a Proposed Decision recommending action consistent with staff's report on August 8, 2022, and approved a final decision (D.22-09-026) on September 15, 2022. While gas line extension subsidies were eliminated effective July 1, 2023, the Commission made available a pathway for the IOUs to request special exemptions for cases in which a builder can demonstrate that receiving such a subsidy would further California's climate goals.

The elimination of gas line extension subsidies was followed by a new staff report issued for comment on July 26, 2023, recommending the elimination of electric line extension subsidies for mixed-fuel new construction (i.e., new construction that would rely on both electricity and gas and/propane as a fuel source instead of electricity alone). The staff report estimated annual electric ratepayer savings potentially as high as $486,524,443 if mixed-fuel new construction stayed at 2022 levels.[274] On December 14, 2023, the Commission adopted D.23-12-037, which approved the staff report's recommendations with minor modifications. Electric line extension subsidies will no longer

[272] R.19-01-011 Phase 3 Staff Proposal.
[273] *Ibid*, p. 31.
[274] R.19-01-011 Phase 3B Staff Proposal.

be available for mixed-fuel new construction effective July 1, 2024, unless a project is otherwise exempted through the same process established pursuant to D.22-09-026.

IOU Perspectives on Gas Rate Containment

The following represents IOUs' perspectives on gas rate containment, as reported to the CPUC. [275] Sempra states that an appropriately set monthly fixed charge would allocate a fair share of fixed costs to customers who choose to partially electrify (e.g., appliance electrification) their home, but who maintain their gas service at lower consumption levels. PG&E did not provide specific recommendations on gas rate containment as its comments were entirely electric-focused.

Non-CPUC Regulations that Impact Rates

CalGem Storage Regulations

In the aftermath of the 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. 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. This reduction in injection and withdrawal capacity may have market impacts.

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.[276] The 2012 rupture of a pipeline near a

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[275] From the IOUs' reports on recommendations to limit cost and rate increases. Full IOU reports available here; *See* "2024 Electric and Gas Costs Utility Reports" bullet point under "Reports and White Papers" section of the webpage. Inclusion of IOU report elements in this report does not imply CPUC endorsement.

[276] 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,

highway in Sissonville, West Virginia demonstrated the limitations of the definition of High Consequence Areas (HCAs),[277] 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.[278] Previously, pipeline operators were only required to do inline inspections in High Consequence Areas.

Reconfirming MAOP

The Mega Rule states that MAOP must be reconfirmed for transmission lines in High Consequence Areas and Class 3 and 4 locations and piggable transmission lines in Moderate Consequence Areas that don't have verifiable records that they have met the modern standard.[279] 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.

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.

[277] 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.

[278] 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.

[279] 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.

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

Table 13: 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[280]	Yes
Requires Replacement Pipeline to Be Piggable?	No	Yes

[280] 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.

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 14: Miles of Pipeline Subject to PHMSA Mega Rule

	PG&E	SoCalGas/SDG&E
MAOP Reconfirmation	345	1,040
Materials Verification	210[281]	1,354
Assessment Outside HCA	873.5	253

Source: SED.

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

CARB GHG Regulations

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

Following AB 32, CARB promulgated regulations creating the Cap-and-Trade Program. Under CARB's regulations, large emitters of greenhouse gases must purchase and surrender compliance instruments (typically allowances or offsets) to CARB for each ton of GHG released. This includes electric and natural gas utilities, who must pay for GHG emissions that come from burning fuel for electricity generation or that occur when customers burn purchased fuel. Electric utilities began accruing Cap-and-Trade Program costs January 1, 2013, 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 similar to 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 end of year true-up advice letter process.

CARB also allocates some allowances for free to electric and natural gas utilities on behalf of their ratepayers. Electric IOUs are required to sell these allowances at auction each year and utilize the

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

proceeds for the benefit of ratepayers. Natural gas IOUs may also use some allowances for compliance, reducing the cost passed to customers in rates. Since 2014 (for electric customers) and 2018 (for most natural gas customers) residential customers have received the California Climate Credit as their share of the proceeds from the sale of allocated allowances. Although not part of rates, the California Climate Credit is delivered on-bill automatically to all residential ratepayers, including submetered customers and community choice aggregator (CCA) customers within the footprint of an IOU. Since 2014, as a result of the Cap-and-Trade Program, the average residential electric customer has received around $850 in California Climate Credits, while the average residential natural gas customer has received around $265.

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 $804 million while the California Industry Assistance Credit has totaled $811 million statewide. Natural gas non-residential customers do not receive on-bill assistance.

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

APPENDICES

Appendix A – 2024 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 2024 electric and gas utility reports submitted by PG&E, SCE, SDG&E, and SoCalGas, pursuant to Public Utilities Code Section 913.1: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-rates. See "2024 Electric and Gas Costs Utility Reports" bullet point under "Reports and White Papers" section of the webpage.

Appendix B - A Lexicon of Key Ratemaking Terms and Definitions

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

- **Attrition Year:** In GRC proceedings, a year subsequent to the test year for which formulaic adjustments to the test year revenue requirement are made until the next GRC cycle commences.
- **Bundled Customers:** Customers who get all of their services - generation, transmission, and distribution services - from the Investor-Owned Utilities.
- **Bundled System Average Rate (Bundled SAR):** Bundled authorized revenue requirement divided by bundled forecasted kilowatt-hour sales.
- **Bundled Residential Average Rate (Bundled RAR):** Bundled residential class authorized revenue requirement divided by bundled residential forecasted kilowatt-hour sales.
- **Cost of Service Regulation (COSR):** A form of rate regulation where a regulated entity will be allowed to collect in rates its total cost of providing services plus a reasonable profit.
- **Depreciation:** Capital investments in facilities and assets are initially financed by the utilities' own funding sources and are returned to the utilities with ratepayer funding in the form of depreciation expense. Depreciation spreads the ratepayers' cost of the physical electric plant and systems over its useful life.

- **Distributed Energy Resources (DER):** Distribution-connected generation resources, including energy efficiency, storage, electric vehicles, and demand response technologies.

- **Energy Burden:** Actual home energy costs as a percentage of household income.

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

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

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

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

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

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

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

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

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

- **Rate Base:** The book value, after depreciation, of the generation, distribution, and transmission infrastructure assets owned and operated by the utility for which they may earn a profit. Other things being equal, a larger rate base results in higher net income for utilities.

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

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

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

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

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

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

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

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

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

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

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