2024 CALIFORNIA ELECTRIC AND GAS UTILITY COSTS REPORT

AB 67 Annual Report to the Governor and Legislature

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California Public Utilities Commission

A digital copy of this report can be found at:

https://www.cpuc.ca.gov/AB67Report

Lead Authors:

Nicolas Cross and Regina Momblanco, Electric General Rate Case

Gillian Colman, Gas & Oil Pipeline Costs and Rates

Contributors:

Adam Banasiak, Shelby Chase, Eric Dupre, Julia Ende, Daniel Falk, Peng Gong, Mia Hart, Elisia Hoffman, Kapil Kulkarni, Sarah Lerhaupt, Joshua Litwin, Danny Nguyen, Maya Noesen, Erica Petrofsky, Bridget Sieren-Smith, Yueting Sun, Jonathan Wardrip, Christopher Westling, Wayne Wai-hone Yu, David Zizmor

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Executive Summary

The California Public Utilities Commission (CPUC) issues the 2024 California Electric and Gas Utility Costs Report, Assembly Bill (AB) 67 Annual Report to the Governor and Legislature, pursuant to California Public Utilities Code (PU Code) Section 913, which requires the CPUC to publish the costs to ratepayers of all utility programs and activities currently recovered in retail rates.[1]

The 2024 California Electric and Gas Utility Costs Report, published in 2025, provides a detailed narrative and transparency into factors driving electric and gas rates for 2024 activities.

Key highlights include:

- **Electric costs**: Pacific Gas and Electric Company (PG&E) saw costs of providing electricity services increase in 2024 by 22 percent compared to 2023, mostly due to higher distribution costs approved in its Test Year 2023 General Rate Case (GRC) that included significant wildfire-prevention related costs. Costs for Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) rose slightly in 2024 by 1.5 percent and 0.9 percent, respectively, compared to 2023, with much of the increases due to wildfire prevention costs.
- **Gas costs**: In 2024, the total cost of natural gas for gas utility customers went down by about 4.7 percent, mainly due to a milder winter than 2023, which reduced demand for heating, and a lower average cost to procure natural gas in early 2024 compared to early 2023. These lowered costs resulted in a total core gas procurement decrease of nearly $2.5 billion dollars, or 51.2 percent across all three IOUs from 2023 to 2024. Non-procurement costs, however, are still higher than they were in 2023. Non-procurement costs, such as transportation costs and public purpose charges, have been increasing at an average rate of 9.2 percent per year since 2018, offsetting some of the savings from lower procurement costs.
- **Electric rates multi-year trends**: From 2020 to 2024, across all three electric IOUs bundled system average rates (SAR) increased at an average annual rate of approximately 10 percent and bundled residential average bills increased at an average annual rate of approximately 9 percent, which is above the average annual inflation rate of about 4 percent over the same time period. Two significant drivers of these rate increases are the costs of these utilities' wildfire mitigation programs and their rooftop solar programs. The cost shift created by rooftop solar increased more in this time than in most previous years, from an estimated $6.5 billion to $7 billion.[2] This is both because the capacity of generators on these tariffs continued to increase in 2024 (at a rate exceeding any year but 2022 or 2023's)[3] and because these tariffs' costs increase with electric rates.

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[1] PU Code Section 913 reporting requirements apply to electrical corporations with at least 1,000,000 retail customers in California and gas corporations with at least 500,000 retail customers in California.

[2] See the "Net Energy Metering and Net Billing Tariffs Cost Impacts" sections of the 2023 and 2024 annual Senate Bill 695 Reports (Report to the Governor and Legislature on Actions to Limit Utility Cost and Rate Increases Pursuant to Public Utilities Code Section 913.1).

[3] See capacity data at https://www.californiadgstats.ca.gov.

- **Electric rates one-year trend:** At year-end 2024, PG&E rates were higher than rates at year-end 2023 reflecting in part the later-than-expected implementation of its 2023 GRC on January 1, 2024, however, much of this increase was offset later in 2024 by the removal from rates of large revenue requirements such as those corresponding to wildfire-related costs and a generation cost adjustment.[4] At year-end 2024, SCE and SDG&E rates were lower than rates at year-end 2023 reflecting in part the removal from SCE rates of a large revenue requirement corresponding to wildfire-related costs and generation cost adjustments[5] and lower-than-expected rates due to SDG&E's 2024 GRC not implementing until February 1, 2025.
- **Greenhouse Gas Cap-and-Trade Program**: In 2024, residential, small business, and industrial customers received $1.89 billion in electric and $986 million in natural gas relief on their bills in the form of line item bill credits from the Cap-and-Trade Program.
- **Income-qualified programs**: In 2024, the California Alternate Rates for Energy (CARE) program provided discounts to approximately 4.1 million income-qualified electric customers, which represents roughly 30 percent of electric residential customers in California.
- **Transmission costs:** The three IOUs' total transmission revenue requirements (TRR) decreased from $5.5 billion in 2023 to $4.5 billion in 2024. These downward adjustments were attributable to reductions in expenses and forecast capital costs. As a result of the CPUC's advocacy in FERC rate cases, negotiated rate case settlements are estimated to have saved California ratepayers in excess of $5.4 billion since 2017.

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[4] The largest decreases are detailed by PG&E in their July 2024 Electric Rate Advisory as the removal from rates of recorded costs related to wildfire mitigation activities in PG&E's 2022 Wildfire Mitigation and Catastrophic Events (WMCE) application and removal from rates of certain costs related to purchasing electricity as part of PG&E's 2025 Energy Resource Recovery Account (ERRA) Forecast application.

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

I. Introduction

This 2024 California Electric and Gas Utility Costs Report, AB 67 Annual Report to the Governor and Legislature (AB 67 Report), is submitted by the CPUC to fulfill statutory requirements.

Enacted pursuant to AB 67 (Levine, Chapter 562, Statutes of 2005), California PU Code Section 913 requires the CPUC to prepare a written report on the costs of programs and activities conducted by the four major electric and gas companies regulated by the CPUC. This legislation was enacted in part to determine the effect of various legislative and administrative mandates, and to provide more transparency into factors driving electric and gas rates.

The report is to be submitted to the Governor and the Legislature each year and is required to include the following:

1) Each program mandated by statute and its annual cost to ratepayers.
2) Each program mandated by the CPUC and its annual cost to ratepayers.
3) Energy purchase contract costs and bond-related costs incurred pursuant to Division 27 of the Water Code (commonly known as Department of Water Resources (DWR) related costs).
4) All other aggregated categories of costs currently recovered in retail rates as determined by the CPUC.

This report and prior year reports are available at https://www.cpuc.ca.gov/AB67Report.

Background

This 2024 California Electric and Gas Utility Costs Report (AB 67 Report) provides a detailed narrative of various energy programs in California, along with a breakdown of the underlying costs that drive electric and gas rates, including charts and tables showing how these costs and rates have varied over time. This report focuses on costs from 2024 only.

The report provides the CPUC-authorized revenue requirements for the four major California investor-owned utilities (IOUs or utilities): PG&E, SCE, SDG&E, and Southern California Gas Company (SoCalGas). A utility revenue requirement is the sum of all authorized costs incurred by a utility to provide a set of services to customers during a period of time, typically a one-year period. The authorized revenue requirements and sales forecasts are used to set utility rates.

To account for the discrepancies between authorized revenue requirements (utility costs) and actual revenues (utility sales), the CPUC authorizes balancing account mechanisms. These mechanisms true up the actual revenue to the authorized revenue requirement in the following year. This true-up process mitigates the risk of the utilities collecting more than or less than their authorized revenue requirements, particularly if sales are higher or lower than forecast due to conservation, weather, efficiency programs, consumption increases or other reasons.

This report has several chapters examining the various costs and drivers that are highlighted in this summary Chapter 1. The report considers different electric and natural gas revenue requirement components and identifies the sources of the greatest increases in costs. Chapters II through VI address electric revenue requirements and Chapter VII addresses natural gas revenue requirements. In addition to the detailed summary tables provided throughout the text, Appendix A and Appendix B provide summaries of each IOU's authorized revenue requirements organized by the rate components typically shown on customer bills. Appendix C is a glossary of selected terms. Appendix D contains the 913.9 Report, which looks for duplicative Energy Efficiency programs across California agencies.

Overview

Drivers Behind Electric Utility Cost Changes

The bullets below highlight key-year-over-year changes in various components of the revenue requirements.

Total Revenue Requirements by Utility

- The total company revenue requirement (including transmission)[6] for the electric utilities in 2024 is as follows: PG&E $20.3 billion, SCE $17.5 billion, and SDG&E $4.2 billion, for a total of $42.1 billion in electric-related revenue requirements across the three large electric IOUs (PG&E, SCE, and SDG&E).
- Compared to 2023, the 2024 CPUC-authorized annual revenue requirements[7] for PG&E, SCE, and SDG&E increased by 22 percent, 1.5 percent, and 0.9 percent, respectively.
- The 2024 revenue requirements, and percent change over prior year, for each of the three electric utilities are shown in **Table 1.1**.

[6] The Federal Energy Regulatory Commission has jurisdiction over transmission-related revenue requirements.

[7] All references to revenue requirements are to the CPUC-authorized annual revenue requirement and are in current dollars (not adjusted for inflation) unless otherwise indicated.

Table 1.1: Electric Utility Revenue Requirement Comparison ($000)[8,9]

Utility	2024 CPUC	2023 CPUC	Difference ($000)	Difference %	2024 Transmission	2024 Total Company
PG&E	17,677,99	14,487,49	3,190,498	22.0%	2,663,244	**20,341,23**
SCE	16,413,97	16,177,65	236,314	1.5%	1,116,093	**17,530,06**
SDG&E	3,547,827	3,515,287	32,540	0.9%	685,245	**4,233,072**
Total	**37,639,79**	**34,180,43**	**3,459,351**	**10.1%**	**4,464,583**	**42,104,37**

Drivers of Change in Utility Revenue Requirements

The main drivers of the utility revenue requirement changes were utility specific and driven by the most recent rate cases. PG&E's revenue requirements increase was mainly due to higher distribution-related costs approved in the decision for its most recent general rate case (GRC), D.23-11-069 for Test Year 2023. The rate case decision approved initiatives to reduce wildfire ignition risk such as undergrounding and covered conductor and directed PG&E to upgrade its distribution system to be ready to serve higher customer load and new connections. SCE's revenue requirement increase was due to increased distribution costs, offset by decreased total generation costs (although the per unit cost of generation increased). SDG&E's slight increase was due to increased distribution costs, offset by decreased total generation costs (although the per unit cost of generation increased) and decreased Public Purpose Program costs. The increase in SCE's distribution costs was due to amortizations of the Base Revenue Requirement Balancing Account (BRRBA) and Catastrophic Event Memorandum Account (CEMA), as well as collections for Wildfire Mitigation / Vegetation Management costs. Most of SDG&E's increase in distribution costs was caused by amortizations of the Wildfire Mitigation Plan Memorandum Account (WMPMA), CEMA, and other accounts. SCE and SDG&E's generation costs have decreased due to load migration to community choice aggregation.

The next few bullets review the major drivers that can change revenue requirements: power procurement, distribution costs, transmission costs, public purpose programs, wildfire bonds, and amortization costs.

- **Power procurement costs increased slightly for PG&E and decreased for SCE and SDG&E during 2024.** Power procurement costs include the costs of generating and purchasing electricity as well as capital costs related to those items. **Table 1.2** shows the 2024 revenue requirement for the three electric utilities associated with generating and procuring electricity. These generation revenue requirements only apply to utility bundled customers. Unbundled customers, which include direct access

[8] PG&E Advice Letter 7382-E, SCE Advice Letter 5379-E, and SDG&E Advice Letter 4507-E, effective 10/01/2024, 10/01/2024, and 10/01/2024, respectively.

[9] The CPUC does not have jurisdiction over transmission-related revenue requirements. Hence, the transmission component is shown separately, and the year-over-year comparisons do not include transmission.

customers and community choice aggregation customers, have their own generation rates and they are not included in this report because costs of electric generation and associated procurement are not regulated by the CPUC. The IOUs collect generation revenues in a single combined bill on behalf of the direct access providers and pass along the revenues to energy service providers or community choice aggregators (CCAs).

Table 1.2: Electric Generation Revenue Requirement Comparison for Utility Bundled Customers ($000)

Utility	2024	2023	Difference	
			$000	%
PG&E	5,346,585	4,941,037	405,548	8.2%
SCE	6,172,547	7,580,809	(1,408,262)	(18.6%)
SDG&E	791,098	1,091,201	(300,103)	(27.5%)
Total	**12,310,230**	**13,613,047**	**(1,302,817)**	**(9.6%)**

Most of PG&E's increase in generation revenue requirements is due to a forecasted decrease in the sale of surplus energy, offset by lower forecasts for utility-owned generation (UOG) fuel. Much of SCE's decrease is due to a significant decrease in undercollections for the Energy Resource Recovery Account (ERRA) Balancing Account. SCE also refunded costs as a result of their 2024 ERRA Trigger Mechanism, since the 2024 ERRA proceeding had previously raised rates to address high priced conditions in December 2022 that did not persist; in contrast, SCE's 2023 ERRA Trigger was for an undercollection. SDG&E saw lower forecasts for market purchases/contracts and Renewables Portfolio Standard (RPS) energy contracts, offset by a higher forecast, and an undercollected balance, for UOG fuel.

For additional analysis on generation revenue requirements, see Chapter IV.

- **Electric distribution costs increased for PG&E, SCE, and SDG&E in 2024.** Distribution costs include the costs of providing service at or below a certain voltage (60 kilovolt (kV), 115 kV, and 69 kV for PG&E, SCE, and SDG&E, respectively) that are regulated by the CPUC. **Table 1.3** shows the 2024 revenue requirement for the three electric utilities associated with distribution of energy through the electric grid.

Table 1.3: Electric Distribution Revenue Requirement Comparison ($000)

Utility	2024	2023	Difference	
			$000	%
PG&E	11,289,414	8,148,501	3,140,913	38.5%
SCE	8,957,457	7,251,843	1,705,614	23.5%
SDG&E	2,440,916	1,923,385	517,531	26.9%
Total	**22,687,786**	**17,323,729**	**5,364,057**	**31.0%**

PG&E's increase was mainly due to higher distribution-related expenses approved in PG&E's 2023 General Rate Case; these GRC distribution costs included significant wildfire-prevention related amounts. SCE's increase was due to amortizations of the BRRBA and CEMA, as well as collections for Wildfire Mitigation / Vegetation Management costs. Most of SDG&E's increase was caused by amortizations of the WMPMA, CEMA, and other accounts.

For additional analysis on distribution revenue requirements, see Chapter III.

- **Compared to 2023, the total electric transmission costs charged to ratepayers in 2024 decreased for PG&E, SCE, and SDG&E.** Transmission rates include the costs of providing service at or above a certain voltage (60 kV, 115 kV, and 69 kV for PG&E, SCE, and SDG&E, respectively) that are part of the electric grid controlled by the California Independent System Operator (CAISO) and regulated by the Federal Energy Regulatory Commission (FERC). **Table 1.4** shows the 2024 electric transmission costs compared to 2023 for the three electric IOUs.

Table 1.4: Electric Transmission Cost Comparison ($000)

Utility	2024	2023	Difference	
			$000	%
PG&E	2,663,244	3,272,496	(609,252)	(18.6%)
SCE	1,116,093	1,354,762	(238,668)	(17.6%)
SDG&E	685,245	860,184	(174,939)	(20.3%)
Total	**4,464,583**	**5,487,441**	**(1,022,859)**	**(18.6%)**

The across-the-board reductions in transmission costs in 2024 buck the historic upward trend of transmission costs. PG&E's 18.6 percent drop is attributed to a downward adjustment in its annual true-up of 2022 rates, an over $225 million decrease in Administrative and General (A&G) costs related to wildfire claims reserves and liability insurance costs, a $15 million reduction in Operations and Maintenance (O&M)

costs attributed to decreased line inspections and work, and a decline of over $122 million in PG&E's Transmission Access Charge Balancing Account Adjustment. SCE's lower transmission revenue requirement relates to three factors: a large decrease in the annual true-up from an under-collection in 2023 to an over-collection in 2024, the removal for 2024 of a 2022 A&G expense accrual attributable to an upward adjustment to the 2017/18 wildfire/mudslides reserve and a large credit in the Transmission Revenue Balancing Account Adjustment. SDG&E's decrease is related to a reduction in the 24-month forecast plant additions and a shift from an under-collection to an over-collection for the 2024 true-up.

For additional analysis on transmission revenue requirements, see Chapter III.

- **Public Purpose Program costs decreased for PG&E, SCE, and SDG&E in 2024.** These Public Purpose Programs (PPPs) include Energy Efficiency, Energy Savings Assistance (ESA), and California Alternative Rates for Energy (CARE), among other programs. A primary driver of the decrease in PPP costs for all three utilities was a decrease in Energy Efficiency program-related collections. PG&E's 2024 energy efficiency revenue requirements were $109 million lower than its energy efficiency revenue requirements in rates at the end of 2023. PG&E's decrease was also due to the amortization of the CARE balancing account, which tracks the recovery of the CARE discount from non-CARE customers; the amortization reversed from an undercollection in 2023 to an overcollection in 2024. Much of SCE's decrease in PPP costs was due to a change in energy efficiency revenue requirements, which updated SCE's Energy Program and Portfolio True-Up for program years 2024-2027. SCE's decrease in PPP costs was also due to the removal from 2024 revenue requirements and rates of collections for the Energy Efficiency Market Access Program and the School Energy Efficiency Stimulus Program; SCE had fully recovered authorized funding for both programs by the end of 2023. Much of SDG&E's decrease in PPP costs was due to the 2024 refund of $31 million related to unspent and uncommitted Post-1997 Electric Energy Efficiency Balancing Account (PEEEBA) funds. **Table 1.5** shows the 2023 and 2024 revenue requirement for the three electric utilities associated with PPPs.

For additional analysis, see Chapter V.

Table 1.5: Electric PPP Revenue Requirement Comparison ($000)

Utility	2024	2023	Difference	
			$000	%
PG&E	577,634	878,915	(301,282)	(34.3%)
SCE	681,788	728,767	(46,979)	(6.4%)
SDG&E	314,370	499,337	(184,967)	(37.0%)
Total	**1,573,791**	**2,107,020**	**(533,228)**	**(25.3%)**

- **Bonds and Regulatory Fees increased for PG&E and SDG&E during 2024 while SCE saw a slight decrease.** During the era of electric restructuring, the State and the utilities issued a series of bonds to amortize the costs of energy restructuring and the energy crisis of 2000-2001. These bonds were retired in September 2020. Beginning October 1, 2020, the revenue requirements associated with repaying those bonds were replaced by charges to support the AB 1054 Wildfire Fund. Fees include charges levied against the utilities by state and local governments (to cover the costs of regulation and oversight, for example). Fees are included as specific components of other revenue requirements. **Table 1.6** shows the 2024 revenue requirements for the three electric utilities associated with bonds and fees. For additional analysis on bonds and fees, see Chapter VI.

Table 1.6: AB 1054 Wildfire Bonds and Related Fees
Revenue Requirement Comparison ($000)

Utility	2024	2023	Difference	
			$000	%
PG&E	752,674	512,433	240,241	46.9%
SCE	595,351	608,729	(13,378)	(2.2%)
SDG&E	84,674	75,465	9,209	12.2%
Total	**1,432,699**	**1,196,627**	**236,072**	**19.7%**

During 2024, much of the variation in the revenue requirements for bonds and fees was due to an increase in fixed recovery charges from the issuance of a new recovery bond.

For additional analysis on wildfire-related bonds, see Chapter VI.

- **The revenue requirements for PG&E, SCE, and SDG&E increased in 2024 due to routine adjustments for amortizations of balances in various balancing and/or memorandum accounts.** These are routine adjustments to previously authorized balancing and memorandum accounts such as those associated with the energy procurement, distribution, transmission, and Public Purpose Programs costs discussed above. **Table 1.7** shows the effects of these adjustments on the revenue requirements for the electric utilities.

Table 1.7: Adjustments to the 2024 Revenue Requirement ($000)

Utility	Forecasted 2024 Costs	Amortization Adjustments	Authorized 2024 Revenue Requirement	Difference %
PG&E	15,731,166	1,946,826	17,677,992	12.4%
SCE	15,967,132	446,840	16,413,972	2.8%
SDG&E	3,127,245	420,582	3,547,827	13.4%
Total	**34,825,543**	**2,814,248**	**37,639,791**	**8.1%**

Utilities add amortizations of balancing and/or memorandum accounts to the annual revenue requirement to recover costs of prior years and set rates incorporating this adjustment. The information in this report refers to the adjusted annual revenue requirement to show the annual cost to ratepayers.

Wildfire-Related Costs

As noted in several areas above, utility spending on wildfire prevention and wildfire bond costs are a significant part of utility electric rates in California. California is experiencing an increase in wildfire events due to several factors, including extended periods of drought, increased fuel for fires, and unprecedented conditions that are leading to extreme weather events. In an effort to reduce wildfire risks related to electric utility infrastructure, the large IOUs are making an unprecedented level of investment to prevent electric gird related wildfires; as a result of these efforts California wildfire prevention costs in 2024 comprise 27 percent (PG&E), 17 percent (SCE), and 10 percent (SDG&E) of the total revenue requirement, as shown in **Table 1.9** below.

Wildfire investments have increased as a result of state law change and other policy changes. The Legislature enacted several bills in response to wildfires in 2018 and 2019 and the CPUC has opened multiple proceedings to address the impact of wildfires on the utilities and their customers.

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.[10]

[10] See IOU's 2023-2025 WMP documents at https://energysafety.ca.gov/what-we-do/electrical-infrastructure-safety/wildfire-mitigation-and-safety/wildfire-mitigation-plans/2023-wildfire-mitigation-plans/.

SB 901 and AB 1054 required the CPUC to allow the IOUs to open memorandum accounts to track spending to implement their WMPs. Since Energy Safety is reviewing the expenditure plans, the CPUC is limited in its ability to reject wildfire related proposed spending in GRC cases at the CPUC. Instead, the IOUs forecast the majority of their WMP costs in their General Rate Cases (GRC). In addition, the IOUs may seek recovery of incremental spending above the forecast if recorded in the memorandum accounts in their GRCs or through a separate application. 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, in their GRCs. Wildfire insurance costs that are incremental to the insurance costs authorized in the GRCs (e.g., if actual insurance costs exceed forecasts) 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. (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.) The IOUs also track eligible costs to respond to catastrophic events, including wildfires, in their Catastrophic Event Memorandum Accounts (CEMA).[11]

Revenue Requirements in Rates

Prior to 2020, wildfire prevention spending by utilities was not broken out separately from other utility spending. For PG&E and SCE, significant wildfire prevention-related operating expenses, including vegetation management efforts and wildfire liability insurance coverage, began to appear as separate lines in revenue requirement, and ultimately in rates, relative to total revenue requirement starting in 2021. Wildfire-related capital expenditures, such as installing covered conductor or undergrounding portions of a distribution system to prevent wildfires, have continued to gradually increase over the 2021 – 2024 period but are not yet a significant portion of the total revenue requirement in rates. Wildfire-related revenue requirement for recent years is shown in **Table 1.8** below.

[11] 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.

Table 1.8: Wildfire-Related Revenue Requirement, 2019-2024 ($000)[12,13]

Utility	2019	2020	2021	2022	2023	2024
PG&E	74,600	743,289	2,610,145	3,263,238	3,179,780	5,404,304
SCE	288,505	1,006,463	1,547,544	1,634,564	2,007,290	2,930,405
SDG&E	126,127	182,419	321,511	376,115	371,738	412,873

SDG&E has a lower percentage of wildfire-related revenue requirement to total revenue requirement in recent years. This situation is partly due to how SDG&E had spent significant funds in prior years to harden its distribution and transmission system after the 2007 Witch Creek Fire. Additionally, while PG&E and SCE have already begun collecting wildfire mitigation costs booked in memorandum accounts established by SB 901, SDG&E's 2019-2023 wildfire costs are currently under the CPUC's review and have not been reflected in the current revenue requirement.[14]

The year-end 2024 wildfire-related revenue requirement amount for each IOU is shown in **Table 1.9**[15]:

Table 1.9: 2024 Wildfire-Related Revenue Requirement

Utility	2024 Wildfire-Related Revenue Requirement ($000)	2024 Total Revenue Requirement ($000)	2024 Wildfire-Related Revenue Requirement % of Total Revenue Requirement
PG&E	5,404,304	20,341,236	27%
SCE	2,930,405	17,530,066	17%
SDG&E	412,873	4,233,072	10%

12 Source: IOU data responses to SB 695 Report

13 The wildfire revenue requirement includes recovery for catastrophic event memorandum account (CEMA) costs. CEMA proceedings include all CEMA-eligible costs, a small portion of which may be unrelated to wildfire, such as restoration of service after winter storms.

14 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.

15 Total revenue requirement for each utility is taken from the "Total Company" column of Table 1.1, above.

Electric Utility Rate Trends Over Time

This report focuses on all authorized revenue requirements to provide system wide electric services.[16] System authorized revenue requirements and sales forecasts are used to set utility rates for both bundled and unbundled customers. The CPUC calculates a Bundled SAR by dividing the authorized bundled customer revenue requirement by the authorized forecasted sales. Bundled SAR are presented in this report as bundled customers take all IOU services−generation and delivery−whereas unbundled customers take delivery service only.[17] The bullets below highlight bundled SAR trends over time:

- Since 2020, all three electric IOUs have had increases in bundled SAR above the rate of inflation (**Figure 1.1**).[18]
- From 2020 to 2024, bundled SAR across the three electric IOUs increased at an average annual rate of approximately 10 percent (**Table 1.10**), which is above the average annual inflation rate of about 4 percent over the same time period.
- From year-end 2023 to year-end 2024, SCE's bundled SAR decreased 0.7 cents per kilowatt-hour (¢/kWh) to 25.9 ¢/kWh, PG&E's increased 3.6 ¢/kWh to 34.9 ¢/kWh, and SDG&E's decreased 5.2 ¢/kWh to 33.3 ¢/kWh.[19]

Bundled SAR can be further broken down by customer class e.g., residential, small commercial, etc., and each class rate may have one or more rate schedules associated with it. For example, the bundled residential average rate (RAR) is the authorized revenue requirement allocated to the residential class divided by the bundled residential class sales forecast. However, the rate a bundled residential customer may see on their bill will reflect the customer's rate schedule e.g. a residential time-of-use rate and whether the customer is enrolled in a rate discount program such as the California Alternate Rates for Energy (CARE) program.

A major cause of an accelerating pace of rate increases in the 2020s has been the declining sales forecasted due to the net energy metering (NEM) tariffs and net billing tariffs (NBT) described in Section V. Also, NEM customers are compensated for electricity exported to the grid at the retail volumetric rate, which

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[16] Authorized revenue requirements amounts are generally smaller than the corresponding authorized costs because capital-related costs, when converted to revenue requirement, go into rates gradually over a long period of time. For more information about converting costs to revenue requirement, see the annual 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).

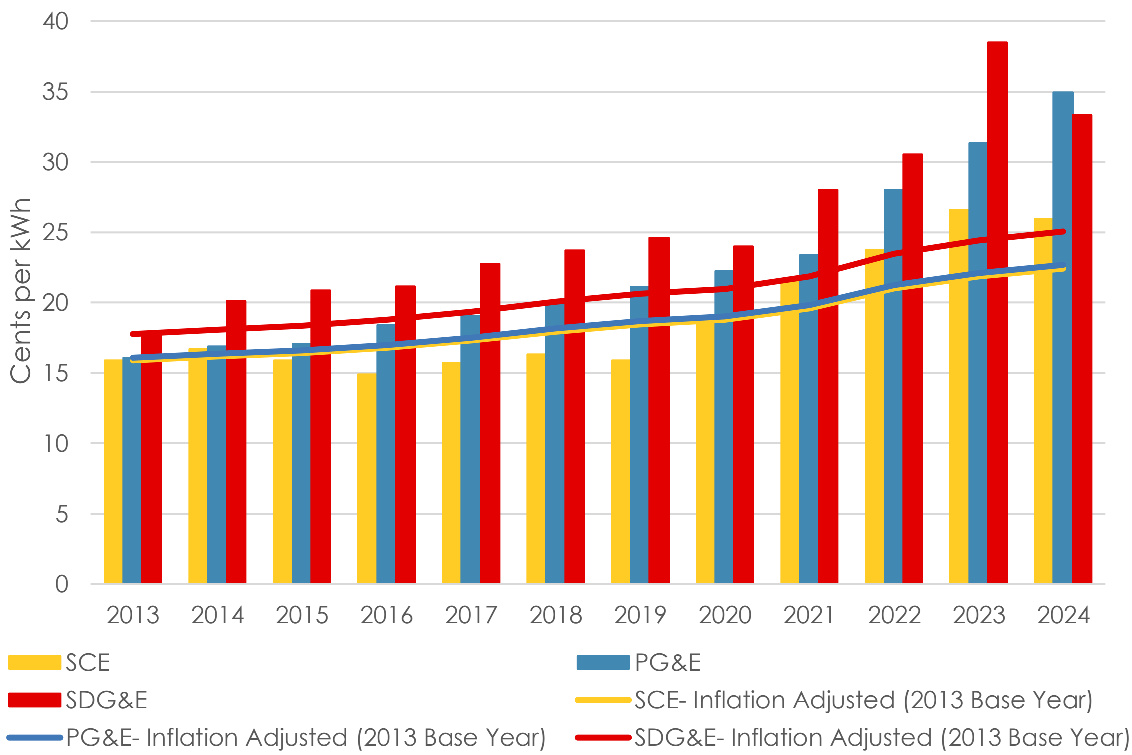
[17] Unbundled customer generation service is provided by a separate energy service provider (usually a Community Choice Aggregator (CCA) or Direct Access (DA) service provider) and is not regulated by the CPUC.

[18] Rates are a function of both revenue requirement and sales. All three utilities experienced declines in bundled kWh sales over the 2020 – 2024 period, which generally leads to increased bundled system average rates when the bundled revenue requirement remains flat or rises. For more information about the effect of sales on rates, see the annual 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).

[19] Year-end 2024 rates are from PG&E Advice Letter 7382-E, SCE Advice Letter 5379-E, and SDG&E Advice Letter 4507-E, all effective 10/01/2024. A comparison of the Total Company revenue requirements in Table 1.1 of this report with the Total Company revenue requirements in Table 1.1 of the 2023 AB 67 Report shows ($000): an increase of $2,581,247 for PG&E, a decrease of $2,354 for SCE, and a decrease of $142,399 for SDG&E.

exceeds the marginal cost of avoided wholesale generation purchased for that customer. Since April 2023, new customer-generators have received compensation through the NBT, which provides compensation that is more aligned with the value of the generation the systems provide. The cost of new customer-sited generation to ratepayers, however, is not fully mitigated by the NBT: due to the continued ability to bypass costs by using self-generated energy.

Figure 1.1: Trends in Electric Bundled System Average Rates (2013-2024)[20]



Annual Inflation Rate Change (2014-2024)[21]											
2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	**Average (2020-2024)**
1.83%	1.46%	2.28%	2.94%	3.7%	2.97%	1.67%	4.25%	7.36%	4.02%	2.54%	**3.97%**

[20] Bundled System Average Rates reflect bundled authorized revenue requirement and bundled forecasted sales for all customer classes.

[21] Source: California Department of Finance, November 2024 CPI.

Table 1.10: Year-Over-Year and 2020-2024 Average Change in Electric Bundled System Average Rates (Year-End, ¢/kWh)

Utility	2020	2021		2022		2023		2024		Average 2020 - 2024
	Rate	Rate	% Change	Rate	% Change	Rate	% Change	Rate	% Change	% Change
SCE	18.5	21.6	16.8%	23.7	9.7%	26.6	12.2%	25.9	(2.6%)	9.0%
PG&E	22.2	23.4	5.4%	28.0	19.7%	31.3	11.8%	34.9	11.5%	12.1%
SDG&E	24.0	28.0	16.7%	30.5	8.9%	38.5	26.2%	33.3	(13.5%)	9.6%

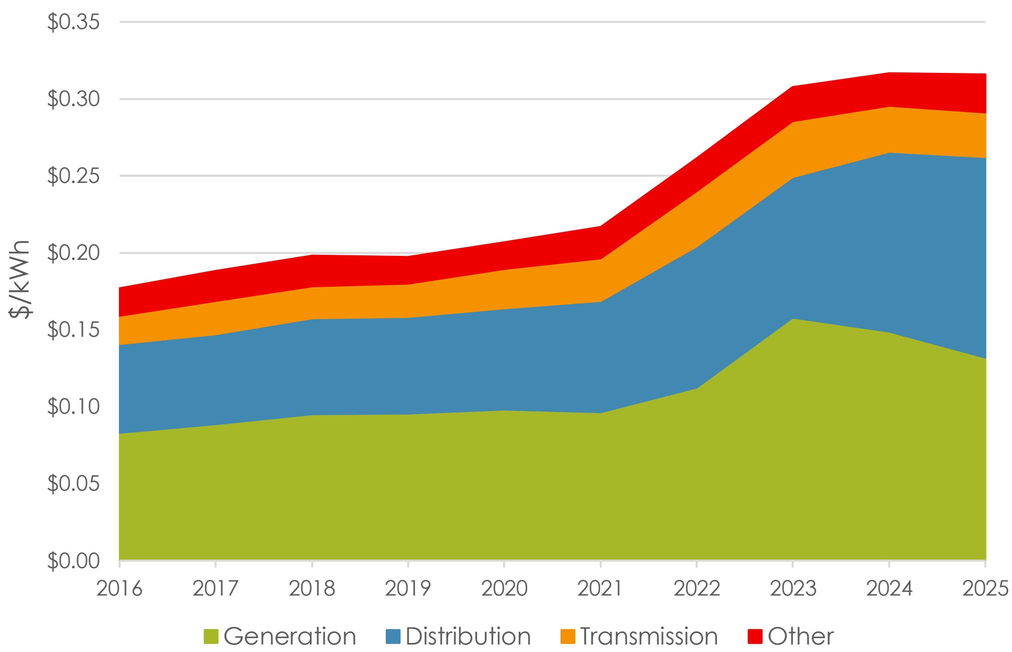
- **Electric generation and distribution are the largest components of electric rates.** As shown in **Table 1.11**, utility-owned generation and purchased power sources, plus distribution, collectively account for approximately 83 percent of the utilities' electric rates.[22]

It is necessary to understand trends in the relative costs of the utility cost components as a system average rate instead of based on the revenue requirements because generation revenue requirements are based on bundled sales and other revenue requirements are based on system sales.

Importantly, generation revenue requirements have decreased since 2016 because load has migrated from IOUs to CCAs since 2016, which has reduced the IOUs' bundled sales. **Figure 1.2** below illustrates trends in the combined bundled system average rate across all three IOUs and in the system average rate for each individual IOU. Until 2023, generation was the largest cost component in rates with the most significant increases. Since 2023, generation costs have decreased by 6.4 percent, while distribution costs have increased by 22.1 percent.

[22] All bundled system rate components based on the authorized revenue requirement allocated to bundled customers–who take generation and delivery services–divided by the bundled sales forecast.

Figure 1.2: Trends in Combined IOU Bundled System Average Rate



As can be seen in **Figure 1.2** above, the bundled system average rate of all three IOUs combined has steadily increased.

Figure 1.3: Trends in PG&E's Bundled System Average Rate

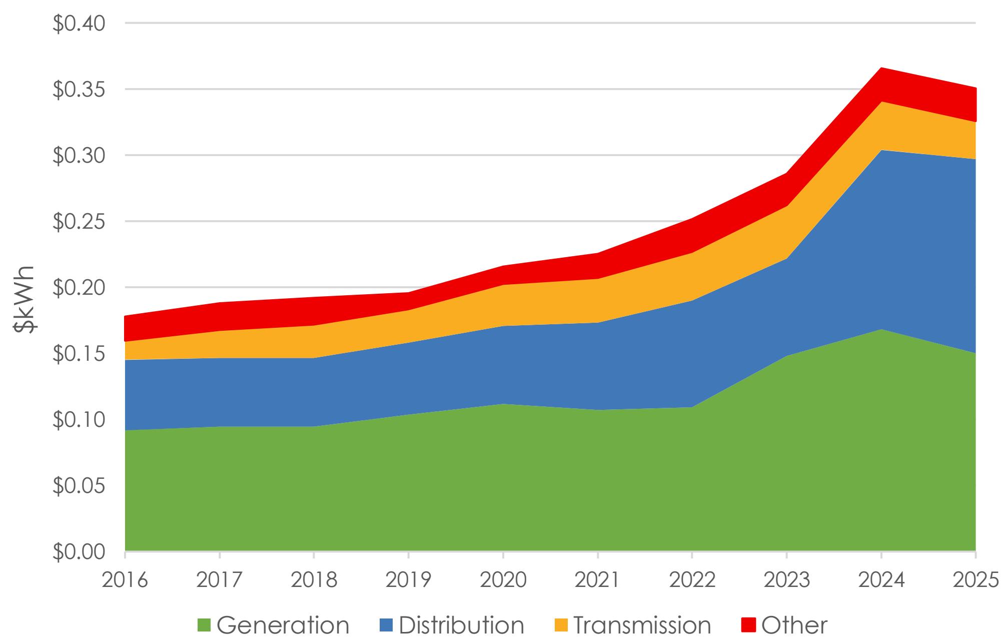
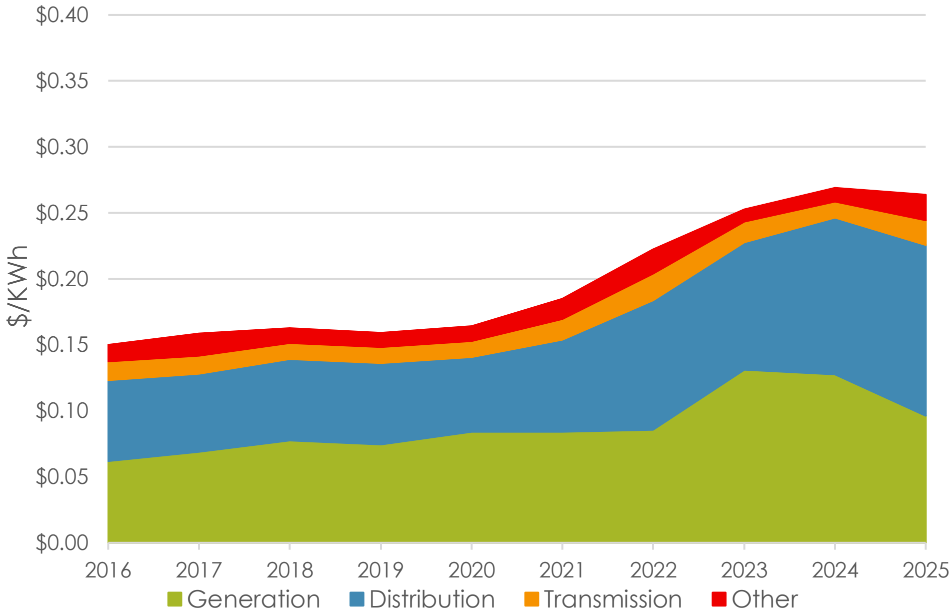
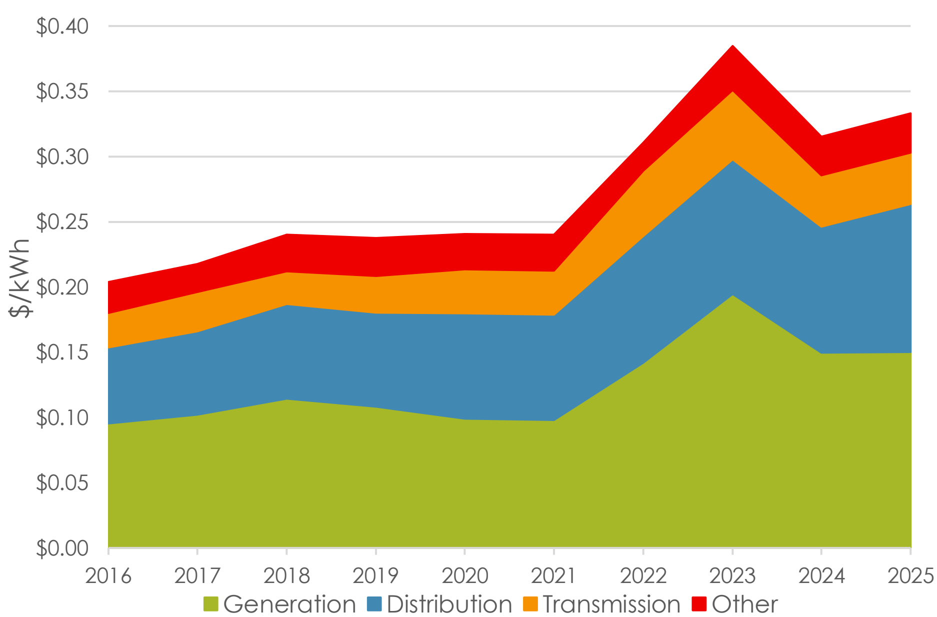


Figure 1.4: Trends in SCE's Bundled System Average Rate



Overall, both PG&E's and SCE's bundled system average rates have been increasing as shown in **Figure 1.3** and **Figure 1.4**. SCE's rate declined in 2025 due to an overcollection the previous year (i.e., decreasing revenue requirement) that led to an ERRA Trigger application (A.24-05-025), which was implemented in rates on October 1, 2024.

Figure 1.5: Trends in SDG&E's Bundled System Average Rate



SDG&E's bundled system average rate has consistently increased with a decline in 2023-2024, as shown in **Figure 1.5**.

Table 1.11: 2024 Electric Bundled System Average Rate Component Values (Year-End, ¢/kWh)

Bundled System Rate Component	PG&E	SCE	SDG&E
Generation[23]	14.9	10.6	15.0
Distribution	13.8	12.9	11.2
FERC Transmission	3.6	1.4	3.9
Public Purpose Program	2.2	0.9	1.7
Other	0.4	0.1	1.4
Total	**34.9**	**25.9**	**33.3**

Table 1.11 shows that currently, generation is the largest rate component for PG&E and SDG&E and the second largest rate component for SCE.

Drivers Behind Gas Utility Cost Changes

The bullet below highlights key year-over-year changes in the components of the revenue requirements.

- **In 2024, total natural gas revenue requirement decreased by 4.7 percent from 2023, a welcome decline relative to 11.2 percent increase seen from 2022 to 2023.** The 2024 gas utility revenue requirement was primarily driven by lower commodity procurement costs in early 2024 compared to the same time in 2023. This was due to the mild winter California experienced in 2023-2024. Transportation costs saw an increase in 2024 primarily due to the Other Balancing Accounts category. However, the increase in Public Purpose Program (PPP) costs were less for 2024 compared to 2023. The lower procurement costs largely offset the increases seen in transportation and PPP costs leading to the reduction in revenue requirement from 2023 to 2024.

[23] Generation rate only applies to IOU bundled customers.

II. Determining Revenue Requirements

The determination of the costs needed to fund utility service, as well as the rate-setting processes at the CPUC, have grown more complex over time. The major procedural venues are used to determine the revenues that the utilities are authorized to collect through rates:

- **General Rate Cases (GRCs):** GRCs for the large energy utilities occur on a four-year cycle based on D. 20-01-002. In GRCs, the CPUC evaluates the regulated operations of the utilities and determines the reasonableness of a utility's requests for changes in revenue needed to fund safe and reliable utility service. The GRCs are the main venue for looking at distribution rates. For PG&E, SCE, and SDG&E, the GRCs are divided into two phases. Phase I of a GRC determines the total amount the utility is authorized to collect (also called the "revenue requirement"), while Phase II determines the share of the utility's total cost each customer class is responsible for and the rate schedules for each class.
- **Transmission rate cases at the Federal Energy Regulatory Commission (FERC):** The CPUC is required to allow recovery of all FERC-authorized transmission costs. Because transmission rates are subject to regulatory oversight by FERC, pursuant to AB 1890 (Brulte, 1996), the transmission revenue requirements of the various utilities that participate in the CAISO are determined in FERC proceedings, called Transmission Owner (TO) rate cases.
- **Generation cost cases, or Energy Resource Recovery Account (ERRA) proceedings**: The CPUC annually reviews each utility's fuel and power purchase forecast and, to the extent deemed reasonable, passes through those costs to bundled electric customers without any profit or mark-up for the utility. Some public purpose charges are also authorized here.
- **Program Budget allocations**: Specific program area proceedings in which program budgets are determined. Most program specific costs are recovered through the distribution rate component, or a stand-alone rate component.

Utilities make large, long-term infrastructure investments on behalf of consumers. The utilities earn a rate of return (authorized profit from rate base) on utility-owned capitalized assets and equipment in exchange for the risk associated with being able to collect their costs from customers over the long-life expectancy of those investments. For many cost categories, however, such as purchased power and fuel, there is no rate of return or profit – the utilities are only reimbursed for these costs from customers as "pass-through" costs.

Categorization of Utility Costs

Utility costs or revenue requirements fall into three major categories: generation, distribution, and transmission. While this basic categorization of costs reflects major areas of utility operations or business units, it is also used to determine what portions of utility costs should be paid by different types of customers.

Generation costs

Some customers do not receive full retail service (also known as "bundled service") from the electric utility. Instead, some customers receive generation service from a non-utility load serving entity (e.g., an Electric Service Provider (ESP), or a CCA). Customers who receive electricity from a CCA or ESP only pay a portion of the legacy generation costs for resources procured by IOUs through the Power Charge Indifference Adjustment mechanism, but they do pay transmission and distribution costs.[24] These customers are required to pay non-bypassable charges for the above-market costs of generation procured on their behalf before they departed from bundled service. Additionally, some larger customers receive service at transmission voltage levels and are not charged for use of the utility distribution system. **Table 2.1** shows the major components of the electric IOUs' 2024 revenue requirements.

Table 2.1: 2024 Electric IOU Authorized Revenue Requirements ($000)

Revenue Component	PG&E	SCE	SDG&E
Generation / Energy Procurement	5,053,954	5,069,512	1,001,227
Purchased Power	2,358,098	4,048,229	243,417
Utility Owned Generation Fuel	592,031	268,102	599,983
General Rate Case	2,103,825	753,182	157,828
Distribution – General Rate Case	8,741,084	8,937,477	1,722,187
Transmission	2,663,244	1,116,093	685,245
Demand Side Management and Public Purpose Programs	812,954	1,038,436	608,973
Bonds and Fees	752,674	595,351	84,674
Wildfire Costs[25]	5,404,304	2,930,405	413,873
Total 2024 Revenue Requirement[26]	**20,341,236**	**17,530,066**	**4,233,072**

[24] CCA and ESP customers pay the Power Charge Indifference Adjustment charge to recover the remaining costs for legacy generation that had been procured on their behalf when these customers were served by the utility.

[25] Some costs included in the Wildfire Costs category are also reflected in other revenue components.

[26] The Total 2024 Revenue Requirement line shows total electric utility costs for each utility. Some costs are reflected in more than one revenue component above the Total 2024 Revenue Requirement line. Relatively minor costs, such as non-utility affiliate credits, are not shown.

Rate Base

The rate base is the book value, after depreciation, of the generation, distribution, and transmission infrastructure owned and operated by the utility for the provision of electric service. Utilities earn a regulated Rate of Return (ROR) on rate base based on their capital structure, debt interest rates, and authorized return on equity (ROE). This ROR is the main source of profit for regulated utilities. Other things being equal, a larger rate base results in a higher net profit for the utilities. The opportunity for profit is necessary to attract capital; utility service is a capital-intensive business, requiring billions of dollars to construct, maintain, and operate the systems needed to provide utility service.

Depreciation causes the utilities' rate bases for existing assets to decline over the useful life of the assets, while building new plants or making capital improvements to existing plants causes their rate bases to increase. Changes in rate base also result in changes in the depreciation expense allowance utilities are authorized to collect. As shown in **Figure 2.1** below, the result of these competing effects has historically been a net increase in rate base. **Figure 2.1** indicates that between 2014 and 2024, the utilities' rate bases increased in size from $48.3 billion to $97.0 billion, or a 101 percent increase in nominal dollars over the past decade, triggering corresponding increases in GRC revenue requirements.[27] Utility rate base increases are driven by ordinary rises in the costs of utility components, like the costs of substation equipment or poles, and they are also driven by unusual or one-time costs such as major investments in new capital additions, such as the investment in wildfire mitigation programs, which represented a departure from the ordinary investment cycle.

[27] When adjusted for inflation, the 2014 rate base equals $63.7 billion. Therefore, an inflation-adjusted comparison of rate base from 2014 to 2024 indicates the rate base increased in size from $63.7 billion (adjusted for inflation from $ 48.3 billion) to $ 97.0 billion, or 52 percent.

Figure 2.1: Trends in Electric Utility Rate Base

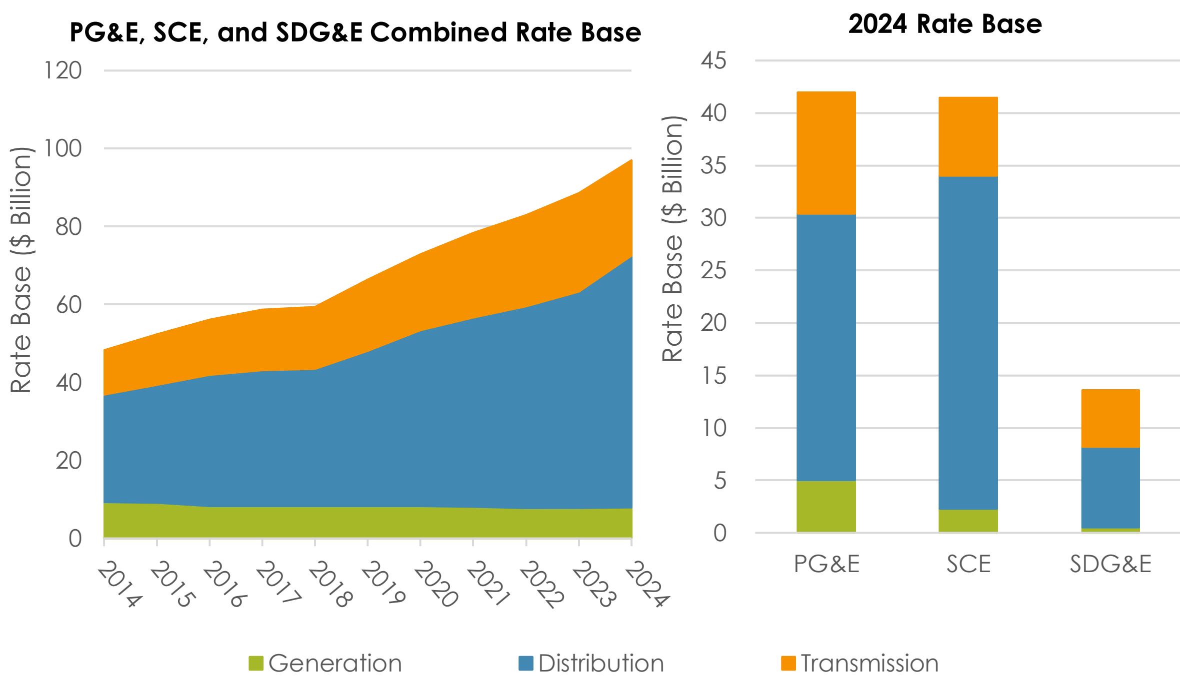


Table 2.2 shows the contributions of generation, transmission, and distribution components to the 2024 rate base.

Table 2.2: 2024 Utility Rate Base Components ($000)

Category	PG&E	SCE	SDG&E	Total
Generation	5,040,605	2,277,457	541,077	**7,859,140**
Distribution	25,347,030	31,720,775	7,646,617	**64,714,422**
Transmission	11,600,356	7,429,296	5,402,844	**24,432,496**
Total	**41,987,991**	**41,427,528**	**13,590,538**	**97,006,058**

III. General Rate Case Revenue Requirements

Costs that utilities can forecast with reasonable accuracy are examined and approved by the CPUC in general rate case (GRC) proceedings. In January 2020, the major utilities were directed by the CPUC to take procedural steps to transition from a three-year GRC cycle to a four-year GRC cycle.[28] In these GRC proceedings, the CPUC sets a pre-specified revenue requirement for the first year in the cycle, or "test year," with formulaic adjustments for the subsequent "attrition years" until the next GRC cycle commences.

The utilities' authorized revenue requirements typically remain unchanged even if the utilities spend more or less than authorized by the CPUC. The exception to this occurs in operations covered by balancing and/or memorandum accounts which can adjust the authorized revenue requirement based on actual spending upon CPUC approval.

Approximately 64 percent of the utilities' electric revenue requirements are set in GRCs at the CPUC and the FERC (FERC sets the revenue requirement for transmission assets), while the remaining 36 percent consists of pass-through of the costs of power procurement, Wildfire Fund and bond charges, nuclear decommissioning trusts, Public Purpose Programs, fees, and regulatory expenses approved by the CPUC.

GRC revenue requirements generally break down into the Distribution, Utility Owned Generation (UOG), and Transmission categories, and each is comprised of the following major cost elements: O&M, Depreciation, Return on Rate Base, and Taxes. **Table 3.1** below summarizes the total CPUC-jurisdictional GRC revenue requirements as broken down into these cost categories for the three electric utilities, followed by detailed descriptions of each.

[28] The CPUC adopted a revised general rate case filing schedule to be applied to all future GRC applications, effective June 30, 2020. Because the utilities were in various stages of their current GRCs, they were directed to take procedural steps to implement the transition to the four-year GRC cycle. Source: CPUC D.20-01-002, January 22, 2020, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M325/K471/325471063.PDF.

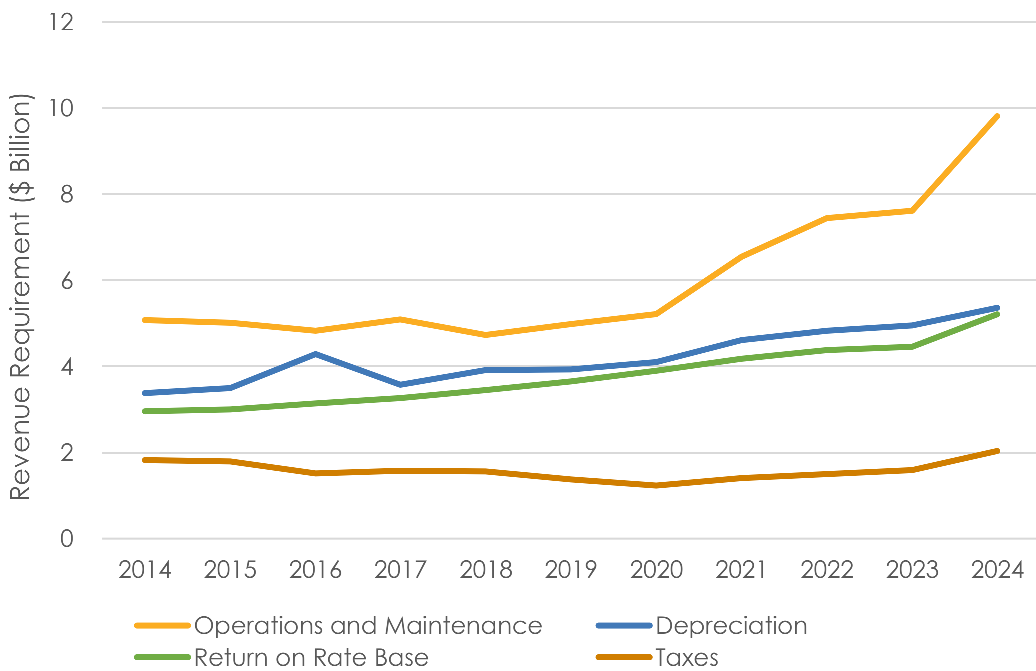
Table 3.1: 2024 General Rate Case Revenue Requirements ($000)[29]

	PG&E	SCE	SDG&E
Operation and Maintenance	5,148,529	3,747,480	915,689
Depreciation	2,655,011	2,284,398	420,323
Return on Rate Base	2,180,393	2,674,233	355,390
Taxes	860,976	984,548	188,613
Total	10,844,909	9,690,659	1,880,015

*This table excludes FERC-determined transmission revenue requirements

Figure 3.1 below shows a ten-year trend in the costs for O&M, Depreciation, Return on Rate Base, and Taxes for the utilities.

Figure 3.1: Trends in General Rate Case Revenue Requirement[30]



[29] Amounts shown include revenues adopted by the CPUC in the utilities' GRCs and additional revenues approved by the CPUC for inclusion in base revenues after the GRC Decisions were issued.

[30] Values shown are for Distribution and Generation Revenue Requirement.

- Operations and Maintenance (O&M): These costs include all labor and non-labor expenses for a utility's operation and maintenance of its generation plants and distribution system. The utilities use O&M budgets to maintain their systems in accordance with requirements to meet safety and reliability standards and industry best practices. Depending on how the utilities manage various projects, they may spend more or less than the CPUC-authorized O&M budget. As mentioned in Chapter I, starting in 2021, significant wildfire prevention-related operating expenses, including vegetation management efforts and wildfire liability insurance coverage, began to appear as separate lines in PG&E's and SCE's revenue requirement relative to total revenue requirement. These significant operating expenses are consistent with the dramatic recent increase in O&M costs shown in Figure 3.1.

To better assess utility spending on ensuring the safe operation of their systems, the CPUC adopted a framework for incorporating risk-based decision-making into GRCs in 2014. This risk-based decision-making framework involves two key components: the filing of a Safety Model Assessment Proceeding (S-MAP) by each of the large energy utilities, and a Risk Assessment Mitigation Phase (RAMP) for each large energy utility one year in advance of its GRC proceeding.

In 2015, the S-MAP applications of the major electric and gas utilities were consolidated, and the utilities and parties discussed the methods by which to assess the risks in their operations. In 2020, a second S-MAP was opened to enhance the RAMP process. Each utility's RAMP proceeding utilizes the reporting format developed in the S-MAP proceeding and describes how the utility plans to assess and mitigate its risks. SDG&E and SoCalGas were the first utilities to initiate the RAMP, in October 2016, followed by PG&E in November 2017, and SCE in November 2018. After the initial RAMP filings, RAMPs have preceded each GRC filing thereafter. For example, in June 2020, PG&E submitted its 2020 RAMP. SDG&E and SoCalGas submitted a succeeding RAMP in May 2021 and SCE submitted its most recent RAMP in 2022. In the general rate cases, the CPUC undertakes a thorough review of O&M costs, separately, for generation and distribution related facilities, and for general plant. Beginning in Test Year 2019, the CPUC incorporated RAMP findings into the utilities' GRC Decisions.

- **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 a depreciation allowance. Depreciation spreads the ratepayers' cost of the physical electric plant and systems over its useful life.
- **Rate of Return on Rate Base:** Because the utilities obtain the upfront financing for all capitalized expenditures, revenue requirements include a rate of return (ROR) on the invested capital.[31] The ROR is the weighted average cost of debt and shareholder equity, and utilities have the opportunity to earn a fair and reasonable return sufficient to support the financial health of the utilities, provided they manage their businesses prudently, which in turn allows the utilities to maintain credit and attract capital. Formerly rates of return were determined in each utility's GRC, the CPUC now determines the rate of

[31] Historical rates of return (both actual and authorized) for PG&E, SCE, SDG&E, and SoCalGas can be found on the CPUC website at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/historical-electric-cost-data/rate-of-return.

return in a separate cost of capital proceeding for the major IOUs. The utilities' actual ROR may be more, or less, than what is authorized by the CPUC, depending on how well the utilities manage their operations and costs. In most instances, if the utilities keep costs below their authorized revenues, actual ROR will exceed the authorized level. GRC ratemaking is aimed at providing the utilities with an incentive to stay within approved, pre-specified budgets. Under this ratemaking treatment, utility profits decline if spending is higher than the GRC authorized revenue requirement, and vice versa.

The utilities do not earn a return on purchased power and fuel expenditures, which, as noted elsewhere in this report, are pass-through costs reviewed in Energy Resource Recovery Account (ERRA) proceedings.

The CPUC also requires the utility to track some costs in "one-way balancing accounts." For expense categories tracked in one-way balancing accounts, if the utility underspends, then the utility returns the funds to ratepayers. If a utility overspends, in a one-way balancing account, the utility must absorb the costs from its profits. One-way balancing accounts are often used for mandated programs to earmark funds for a specific purpose. For activities where there is great uncertainty in cost forecasts, but for which the CPUC wants to encourage the utility to spend in order to meet its obligations (e.g. to procure enough gas to meet its bundled core gas procurement obligations, or to perform safety/reliability work to meet safety obligations), the CPUC often grants two-way balancing accounts which enable the utility to recover reasonable costs that exceed the target dollar amount.

Distribution Revenue Requirement

Since 2014, the total distribution revenue requirement has increased, from $9.5 billion to $19.4 billion (**Figure 3.2**).[32] Over the same time period, depreciation expenses have experienced an approximate 2.5 percent average annual growth rate.[33] The increases in distribution costs are also due to capital additions, ongoing infrastructure modernization, and improvements to the distribution system for wildfire mitigation which have increased rate base, as discussed in the Rate Base section. The O&M for 2024 also includes recovery of certain catastrophic event expenses.

[32] When adjusted for inflation, the 2014 total distribution revenue requirement equals $12.6 billion, which indicates distribution revenue requirement has increased approximately 48 percent from 2014 to 2024 (in 2024 dollars).

[33] Adjusted for inflation.

Figure 3.2: Trends in Distribution Revenue Requirement

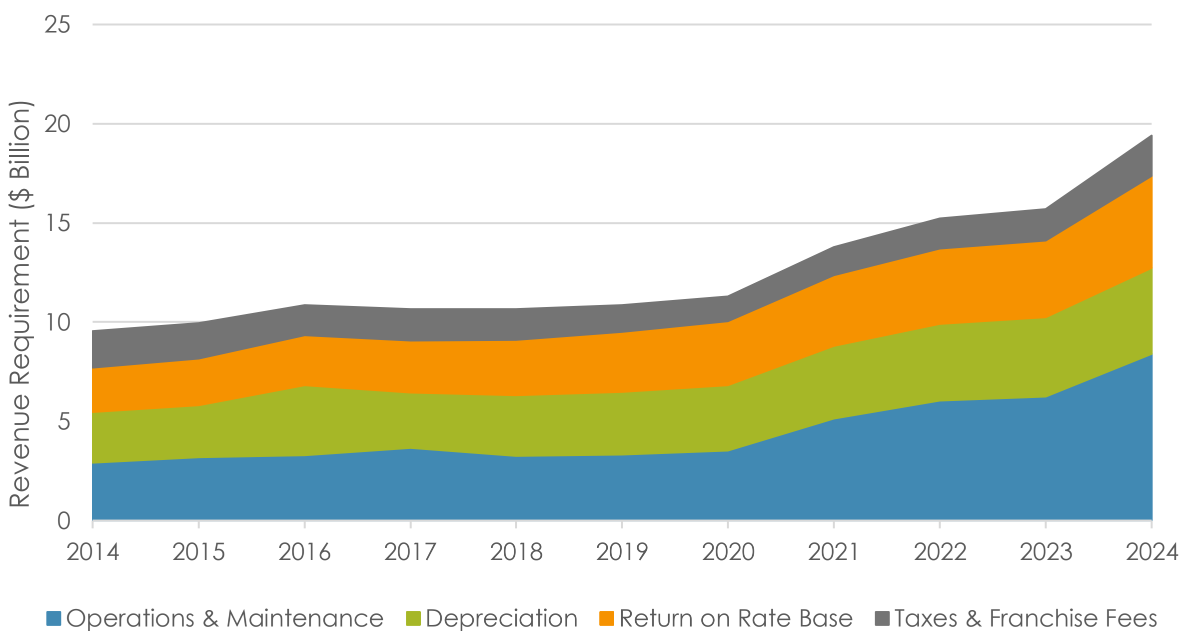


Table 3.2 below shows the contributions of distribution components to the 2024 revenue requirement.

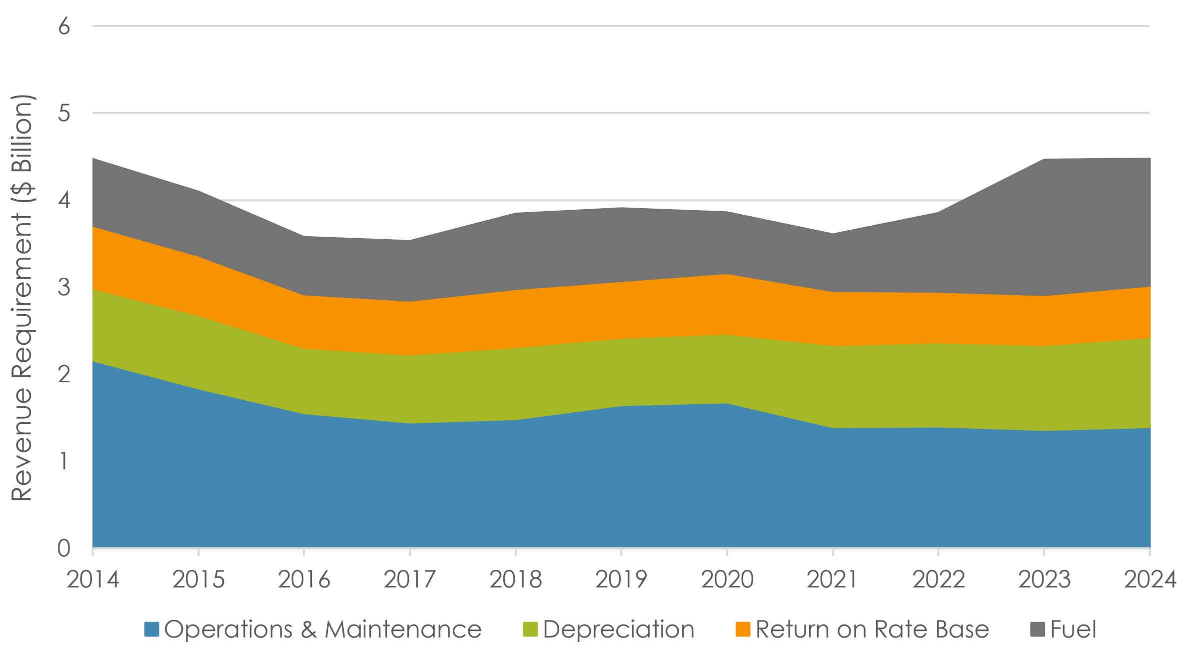
Table 3.2: 2024 Distribution Revenue Requirements ($000)

	PG&E	**SCE**	**SDG&E**
Operation and Maintenance	4,169,544	3,395,165	853,517
Depreciation	1,897,127	2,061,910	370,121
Return on Rate Base	1,813,437	2,495,854	309,936
Taxes and Franchise Fees	860,976	984,548	188,613
Total	**8,741,084**	**8,937,477**	**1,722,187**

Utility Owned Generation Revenue Requirement

The revenue requirement for utility-owned (or retained) generation (UOG) includes O&M costs, depreciation, and return on rate base related to these facilities. As older generating plants depreciate, costs of owning those plants decrease over time, even though costs of operating them may increase. As a result, the generation revenue requirement tends to decrease over time as shown in **Figure 3.3**. As new plants are built by the utilities or capital improvements are made to existing facilities, the capital costs of the new plants typically exceed the capital costs of the old plants they replace. After trending upward in 2023, fuel costs fell slightly in 2024.

Figure 3.3: Trends in Generation Revenue Requirement



*Fuel costs are not included in the GRC but are reflected in generation revenue requirements

Following electric industry restructuring in the late 1990s and the utilities' divestiture of most utility bought fossil-fueled generation, UOG now accounts for only 7 percent of their combined revenue requirements. The 2024 generation revenue requirement for the electric IOUs is shown in **Table 3.3**.

Table 3.3: 2024 Generation Revenue Requirements ($000)

	PG&E	SCE	SDG&E
Operations and Maintenance	978,985	352,315	62,173
Depreciation	757,884	222,488	50,201
Return on Rate Base	366,956	178,378	45,454
Total	**2,103,825**	**753,182**	**157,828**

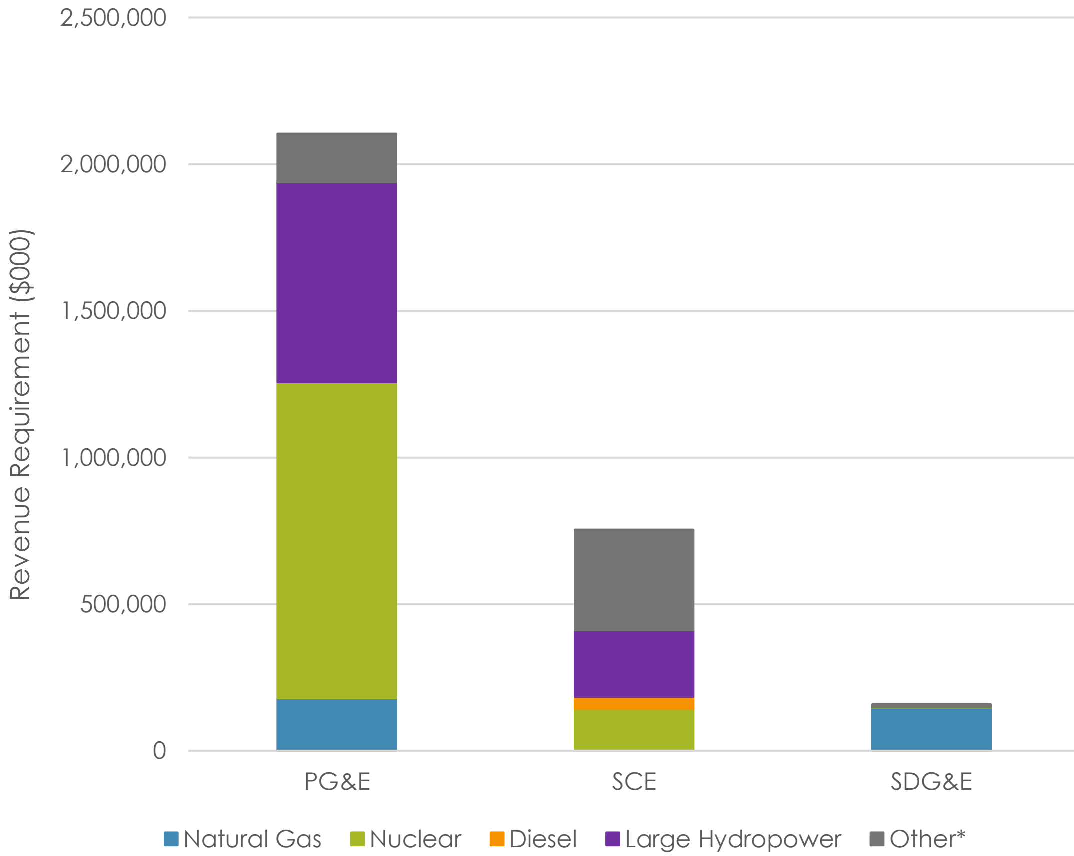
Figure 3.4 and **Table 3.4** show the components of 2024 Generation revenue requirements by UOG sources. PG&E's UOG consists primarily of nuclear power (Diablo Canyon) and several natural gas plants (e.g., the 660-megawatt (MW) Colusa Generation Station, 580 MW Gateway Generating Station, and 163 MW Humboldt Bay Generating Station) and Moss Landing storage. In addition, PG&E's hydroelectric system has 67 powerhouses and produces roughly 3,900 megawatts (MW) of power, and it includes Helms pumped storage facility.[34] SCE's UOG portfolio consists primarily of nuclear (Palo Verde Nuclear Generating Station) and natural gas power plants, including the 1,035 MW Mountain View Power Plant and Peaker plants. SCE's portfolio also includes several hydroelectric plants and a pumped storage facility, as well as 3 new battery energy storage facilities.[35] SDG&E's UOG includes natural gas plants: the 560 MW Palomar Energy Center, the 96 MW Miramar Energy Facility, the 495 MW Desert Star Energy Center, and the 42 MW Cuyamaca Peak Energy Plant.[36] SDG&E also owns Westside Canal, and several other battery energy storage facilities.

[34] See PG&E.'s webpage regarding their hydroelectric system, found at https://www.pge.com/en/about/pge-systems/hydroelectric-system.html.

[35] Separate from GRC revenue requirements, SCE also has Utility-Owned Storage costs related to emergency reliability contracts. Three projects (Anode/Springville, Cathode/Hinson, and Separator/Etiwanda projects) have been authorized.

[36] Desert Star Energy Center was purchased from Sempra Natural Gas in October 2011, and Cuyamaca Peak Energy Plant was purchased from CalPeak Power El Cajon LLC in January 2012.

Figure 3.4: Generation Revenue Requirements by UOG Source



*Other category includes fuel cells, renewables, and coal. SCE's Other category includes New System generation. SDG&E's Natural Gas category includes amortization of NGBA credit.

Table 3.4: Generation Revenue Requirements by UOG Source ($000)

	PG&E	SCE	SDG&E
Natural Gas	179,253	0	146,826
Diesel	0	42,590	0
Nuclear	1,077,047	141,342	1,522
Other	166,660	342,647	9,480
Large Hydropower	680,865	226,602	0
Total	**2,103,825**	**753,182**	**157,828**

Nuclear Revenue Requirement

SCE and SDG&E hold joint ownership in San Onofre Nuclear Generating Station (SONGS) and SCE holds partial ownership in the Palo Verde Nuclear Generating Station (operated by Arizona Public Service).[37] Due to operating issues at SONGS, this facility was taken offline in the first quarter of 2012 and permanently shut down in June 2013. In 2014, SCE and SDG&E were authorized by the CPUC to purchase replacement capacity to alleviate the capacity shortfall, particularly in the LA Basin area. Ratepayer and SCE/SDG&E shareholder responsibilities for SONGS-related costs were determined in a 2014 Decision in the SONGS Investigation, which was subsequently re-opened to determine whether that Decision represented a fair and equitable balance between ratepayer and shareholder recovery. A final Decision on SONGS related costs was issued in August 2018 (D.18-07-037).

PG&E owns and operates the Diablo Canyon Nuclear Power Plant. In January 2018, the CPUC approved a joint request by PG&E and other parties to shutter the plant's two generating units in 2024 and 2025 (D.18-01-022) when its operating license was slated to expire in 2024 and 2025. The CPUC issued a November 2018 Decision (D.18-11-024) that approved $467 million for Diablo Canyon ($363 million for employee retention and retraining, $85 million for a Community Impact Mitigation Program, and $18 million for licensing costs). On 2022, SB 846 (Dodd, 2022) went into effect, requiring the CPUC to consider a five-year extension of Diablo Canyon operations, authorizing a $1.4 billion loan from the state (through the Department of Water Resources) to PG&E to pay for costs to keep Diablo Canyon open, and ordering the creation of a new, annual Diablo Canyon Extended Operations Forecast proceeding to fund the plant during its extension period.[38]

On December 14, 2023, the CPUC approved D.23-12-036 authorizing a contingent five-year extension of Diablo Canyon operations and creating the Extended Operations Forecast proceeding to be filed every March to determine the revenue requirement for the plant in the upcoming year. As directed in SB 846, 2025 will be the final year in which any Diablo Canyon revenue requirement will appear in PG&E's General Rate Case: as of November 2024, all Diablo Canyon Unit 1 costs are now recovered through the Extended Operations Forecast proceeding; all Unit 2 costs will be recovered in the same manner beginning in August 2025. As approved in PG&E's most recent General Rate Case (D.23-11-069), Diablo Canyon's forecast 2024 Operating Costs (i.e., O&M) were $314 million while its forecast 2024 capital expenditures were $6 million.

SCE owns a 15.8 percent share of the Palo Verde Nuclear Generating Station located near Phoenix, Arizona. Arizona Public Service Company (APS) operates Palo Verde while SCE compensates APS for its

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[37] In addition to the list of UOG resources above, SCE also owns and operates a diesel generating facility on Santa Catalina Island. Since the island's load is not connected to the grid, the supply and demand are not included in the forecasts, but the expense is included in the revenue requirements.

[38] The extension period started/starts with the expiration of Diablo Canyon's original Operating License: November 2024 for Unit 1 and August 2025 for Unit 2. The CPUC reversed the order to close Diablo Canyon by 2024/25 in accordance with SB 846 in D.22-12-005 on December 1, 2022.

15.8 percent share of expenses. SCE also oversees and reviews Palo Verde operations through participation in two committees. SCE's 15.8 percent share of Palo Verde's 2024 operating costs (O&M) was approximately $76 million while its share of 2024 capital expenditures totaled approximately $34 million (see testimony submitted in A.23-05-010).

The Nuclear Decommissioning Cost Triennial Proceedings (NDCTP) provide a venue for the utilities to forecast their expected decommissioning costs and for the reasonableness review of recorded costs at their respective nuclear facilities. In D.23-09-004, the CPUC approved PG&E's 2021 NDCTP, authorizing a settlement agreement that, starting in 2023, eliminated the previously approved collection of $112.5 million in annual decommissioning revenue requirement from 2022 through 2029; and refunded $81 million to ratepayers from the nuclear decommissioning non-qualified trust fund. On August 1, 2024, the CPUC approved D.24-08-001, the most recent NDCTP for SONGS and Palo Verde, which had not requested any rate changes.

Apart from the O&M, depreciation and ROR authorized in GRC proceedings, and fuel costs authorized in ERRA proceedings, nuclear generation also results in additional costs, which are collected as separate revenue requirements:[39]

- Fees for disposal and storage of spent nuclear fuel are required by the U.S. Department of Energy (DOE) for temporary and permanent storage facilities. Costs incurred for storage of spent nuclear fuel are currently reimbursed by DOE through claims for prior years consistent with PG&E's 2014 General Rate Case Settlement for Refunding DOE Litigation and Claims Net Proceeds to Customers. In D.07-03-044 the CPUC established the Department of Energy Litigation Balancing Account (DOELBA) to track litigation costs and proceeds received from DOE for the cost of spent nuclear fuel storage on site. SCE and PG&E have been directed to continue to report updated information regarding the net underlying costs supporting the payments from DOE through the litigation and claims process in each nuclear decommissioning cost triennial proceeding.
- Nuclear decommissioning of generating plants at the end of their operating lives is required by the United States Nuclear Regulatory Commission (NRC). To pay for these eventual decommissioning efforts, the utilities were required to establish Nuclear Decommissioning Trust Funds (NDTF). The funds placed into the NDTF are estimated in nuclear decommissioning cost triennial proceedings. The amounts authorized through the nuclear decommissioning costs are funded through rates during the operating lives of the nuclear plants.

[39] Nuclear Decommissioning and DOE Decommissioning & Disposal expenses are categorized with Bonds & Fees because they are collected separately.

Authorized Rate of Return

Authorized rate of return on rate base (ROR) is the weighted average cost of capital used to finance utility capital expenditures. Cost of capital is the combination of the cost of debt and return on equity (ROE) as weighted according to the IOU's capital structure, all of which are authorized in separate Cost of Capital proceedings held every three years. The financing of IOU capital expenditures, or rate base, is included in adopted revenue requirements as part of the cost of service.

Figure 3.5 illustrates the CPUC authorized ROR since 2014 for major energy utilities. The figure does not include ROR authorized by FERC for IOU transmission systems; it includes only the ROR authorized by the CPUC for UOG and distribution. **Figure 3.6** shows trends in the CPUC authorized ROE component of ROR since 2014.

Figure 3.5: Trends in Return on Rate Base (ROR)

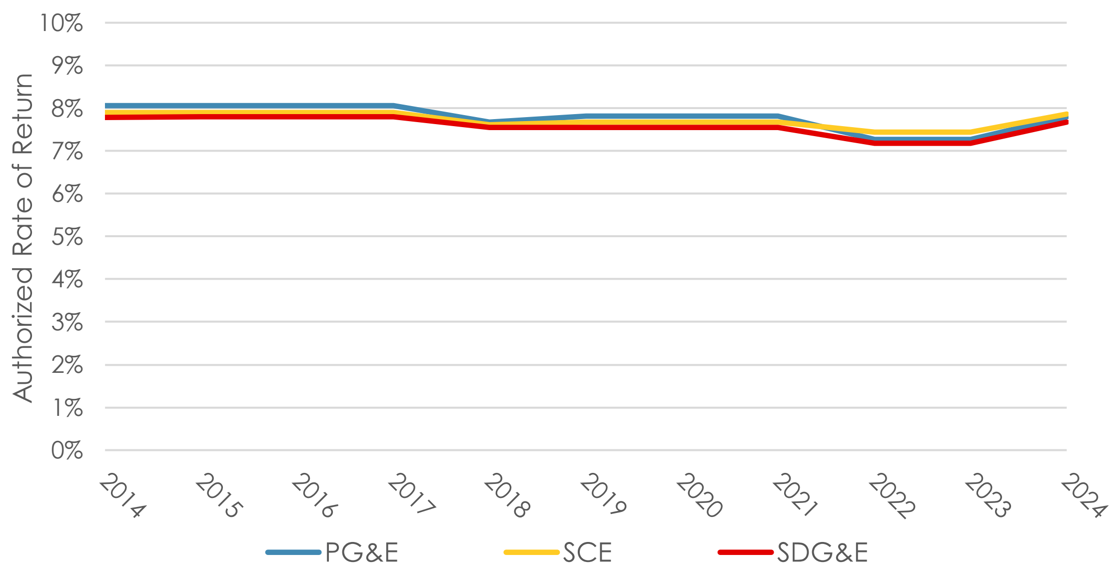


Figure 3.6: Trends in Return on Equity (ROE)

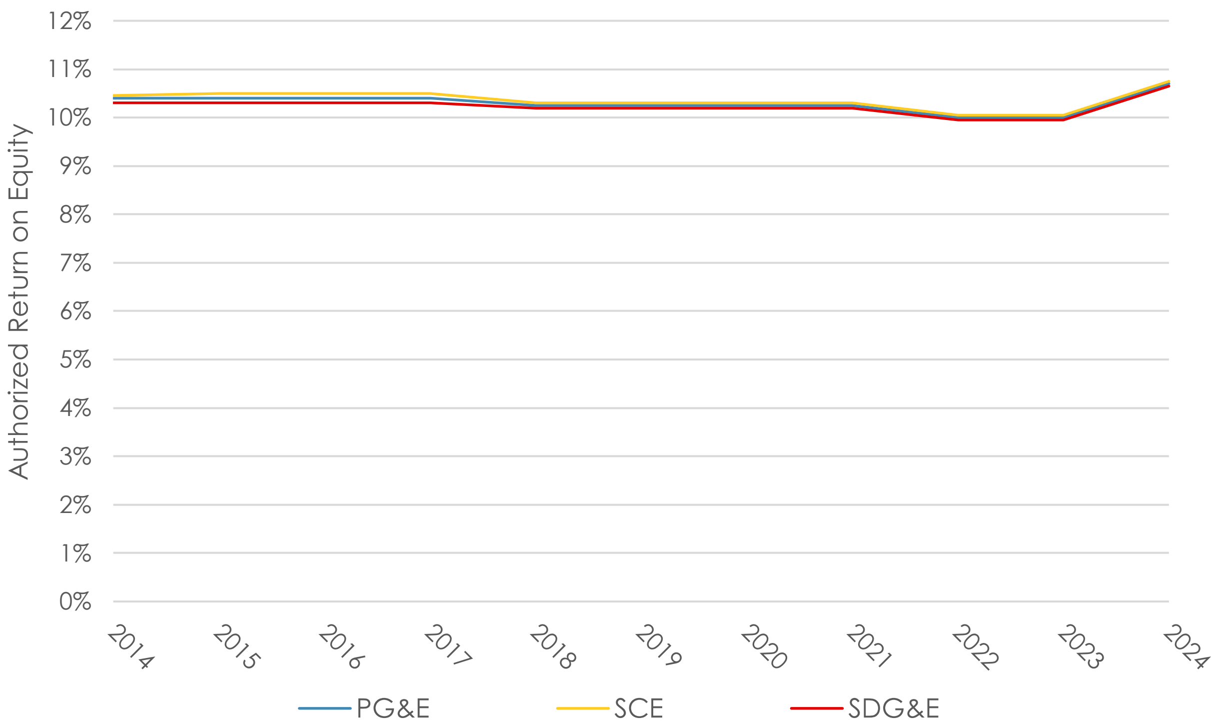
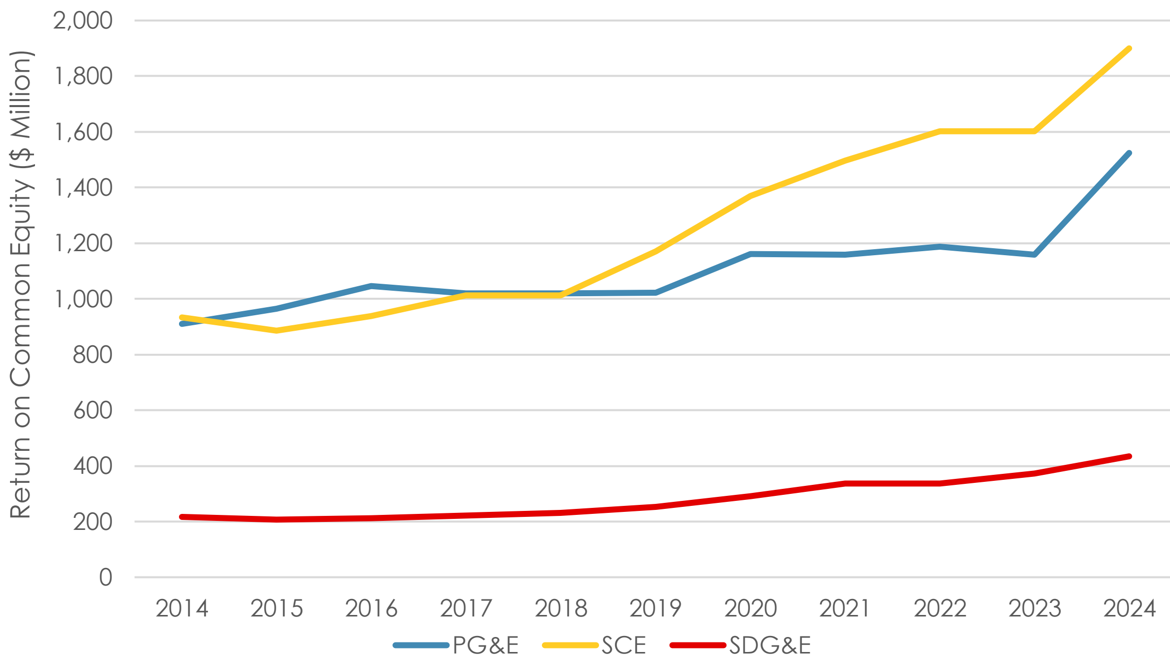


Figure 3.7 shows trends in dollars authorized for return on common equity for major energy utilities since 2014. The figure does not include return on common equity authorized by FERC for IOU transmission systems; it includes only the return on common equity authorized by the CPUC for UOG and distribution.

Figure 3.7: Dollar Trends in Authorized Return on Common Equity



The major energy utilities are currently required to file a cost of capital application every three years, although this review cycle can be, and has sometimes been, modified. In D.22-12-031, the CPUC established the Test Year 2023 cost of capital and authorized continuing the previously authorized cost of capital mechanism through the 2023 test year cycle for SCE, PG&E, and SDG&E, and SoCalGas. In 2024, the IOUs' Rate of Return increased due to the triggering of the Cost of Capital Mechanism when the designated bond index threshold was met during the measurement period. The 2024 Cost of Capital for all IOUs was authorized by Energy Division's Resolution E-5306 and reaffirmed by D.24-10-008 (A.24-04-008).

Transmission Revenue Requirement

Background and Jurisdictional History

As part of energy restructuring authorized by the California legislature, the CAISO was created and given operational control[40] over the bulk transmission grid, including the utilities' FERC jurisdictional transmission lines, on March 31, 1998. FERC assumed authority for determining transmission revenue

[40] The Restructuring Decision (1996) functionally created the implementation of the CAISO through the acceptance of AB 1890 (Sept. 24, 1996).

requirements and setting transmission rates, and each participating transmission owner (PTO) in the CAISO files a FERC transmission owner rate case.[41] The transmission revenue requirements (TRR) authorized by FERC include the same core components (e.g., cost-of-service, depreciation, cost of capital, and taxes) as the general rate cases at the CPUC.

Components of the electric grid are considered part of the interstate transmission network and under FERC's jurisdiction if they are at a higher voltage and meet criteria for connectivity in the transmission system. FERC established a Seven Factor Test in FERC Order 888 to determine whether a portion of the electric grid is transmission or distribution, and as a result, each utility defines its transmission voltage differently. PG&E, SCE, and SDG&E consider all power lines at and above 60 kV, 115 kV, and 69 kV, respectively, as transmission-level voltage. If the lines meet the configuration requirements to make them part of the interstate transmission system, these transmission assets fall under CAISO's operational control and are subject to rate regulation by FERC.[42] All other electric power lines and assets remain under CPUC regulatory control and rate setting jurisdiction.

The three major IOUs file Transmission Owner (TO) formula rate cases at FERC, establishing TRRs and rates that include costs related to cost of capital, depreciation, operating expenses, taxes, and other elements.[43] These formula frameworks typically remain in effect for several years and provide the structure through which forecasted expenses and capital costs can be recovered, as well as the opportunity for annual true-ups to account for over- or under-collection in a previous year's rates. Further, a formula prevents the need for an entirely new rate case at FERC every year.

Transmission Revenue Requirements and Trends

The CPUC is the statutorily designated agency representing the interests of California retail ratepayers at FERC,[44] advocating for just and reasonable rates for California consumers in TO rate cases. Due to the importance and complexity of these rate cases, CPUC Energy Division and Legal Division staff analyze a multitude of expenses and capital projects for cost effectiveness, reliability, safety, and overall prudence of

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[41] FERC Order 888 and 889 (April 1996) required utilities to open transmission grids for access by all generators on a nondiscriminatory basis and functionally unbundled rates for generation, transmission, and ancillary services. The CPUC acceded to this regulatory transfer in its Electric Restructuring Decision D.95-12-063 (Dec. 20, 1995).

[42] Please note that much of SCE's 115 kV assets, while at transmission voltage are configured in such a way that they are not considered part of the interstate transmission system. Therefore, these assets are considered "sub-transmission" and remain under the CPUC's jurisdiction.

[43] The collective TRRs of the IOUs and several other TOs that participate in the CAISO make up the CAISO's Transmission Access Charge (TAC), which is passed onto customers throughout the CAISO region. In addition to the TRR in TO rate cases, balancing accounts can increase or reduce the overall TRR. These balancing accounts compensate for over- or under-collection related to the CAISO's transmission access charge (Transmission Access Charge Balancing Account Adjustment or TACBAA), provide credits to customers for entities outside of California wheeling power through California's grid (Transmission Revenue Balancing Account Adjustment or TRBAA), and a relatively small amount related to reliability services on the transmission grid (Reliability Services Balancing Account Adjustment or RSBAA).

[44] CPUC Code, Section 307(b).

expenditures. CPUC staff examine all formula rate components. This advocacy is essential, as FERC affords the utilities a presumption of prudence for all costs included in a TO rate case. Therefore, it is incumbent on the CPUC and other intervenors to help ensure the rates that FERC approves are just and reasonable.

When a transmission owner files a new rate case at FERC, the CPUC and other intervening parties analyze the filing and typically protest components that appear to be unjust and unreasonable for ratepayers. At that point, FERC usually sets the case for hearing and facilitates a settlement process. The CPUC and others then conduct discovery on the utility's filing to collect further information and develop fact-based recommendations on what we believe is a just and reasonable revenue requirement to protect ratepayers. While the parties typically reach a settlement on the final TRR, there are instances where some components of a rate case, or the entire case, require litigation.

The CPUC and other intervenors fully litigated PG&E's Eighteenth Transmission Owner Formula Rate Case (TO18) transmission owner rate case, which included transmission rates for 2017. In 2024, parties finally reached a settlement which refunds $236.2 million for TO18, $357.7 million for TO19, and $405 million for costs that carried over into PG&E's TO20 rate case, totaling $998.9 million plus interest, in FERC jurisdictional rates. Of this amount, $472.8 million is associated with common, general, and intangible (CGI) costs that PG&E may be eligible to recoup in CPUC jurisdictional rates.[45]

Until 2018, PG&E filed annual stated rate cases, which required in-depth settlement or litigation annually. In October 2018, however, PG&E filed its Twentieth Transmission Owner Formula Rate Case (TO20) at FERC, which remained in effect from May 2019 through 2023. In addition to reaching settlement on the TRR in late 2020, the CPUC and others successfully negotiated establishment of the Stakeholder Transmission Asset Review (STAR) Process. As approximately 75 percent of PG&E's transmission capital projects at that time (i.e., nearly $1 billion annually) received no formal review and approval by the CAISO or the CPUC, the STAR Process provided stakeholders with the opportunity to review substantial data on future projects, participate in stakeholder meetings, and seek additional information to understand, and provide input on, PG&E's capital spending. (See the description below of the CPUC's Transmission Project Review (TPR) Process, which was established in 2024 and builds on the STAR Process and other stakeholder processes negotiated in FERC rate cases.)

PG&E's Total TRR in 2024 was $2.66 billion, $600 million less than the total TRR of $3.27 billion in 2023.[46] The 2024 Total TRR was lower due in part to a substantial downward annual true-up of 2022 transmission rates, an over $225 million decline in administrative general (A&G) expenses related to wildfire claims reserves and liability insurance costs, and a decrease of $15 million in operations & maintenance (O&M) costs attributed to decreased line inspections and work. Another contributing factor was a reduction of over $122 million compared to 2023 in PG&E's Transmission Access Charge Balancing Account Adjustment (TACBAA). The TACBAA in 2024 was a charge to ratepayers of $370 million to make PG&E whole for

[45] PG&E's eligibility to recover certain costs from retail ratepayers is currently under review in PG&E's A.24-09-015 before the CPUC.

[46] The total TRR includes the transmission owner (TO) rate case, which encompasses the total cost of construction, maintenance, and operation of providing transmission service with a rate of return on investment; reliability service costs; and a Transmission Access Charge Balancing Account Adjustment (TACBAA).

under-collection at the CAISO for the difference between what it received for others' use of the PG&E transmission grid and what it had to pay for use of the CAISO controlled grid.

FERC approved the settlement in SCE's most recent TO formula rate case in September 2020. SCE's total TRR in 2024 was $1.12 million, a 17.6 percent decrease from 2023's total TRR of $1.35 billion. The drop in SCE's total TRR was principally attributed to three factors: a large decrease in the annual true-up from an under-collection in 2023 to an over-collection in 2024, the removal for 2024 of a 2022 A&G expense accrual attributable to an upward adjustment to the 2017/18 wildfire/mudslides reserve, and a large credit in the Transmission Revenue Balancing Account Adjustment.

Similar to PG&E's TO20 rate case, as part of SCE's TO rate case settlement in 2020, SCE implemented the Stakeholder Review Process (SRP), enabling stakeholder review of its Five-Year Investment Plan for transmission projects and costs. Very similar to PG&E's STAR Process, the SRP expired in 2023, succeeded by the TPR Process, described below.

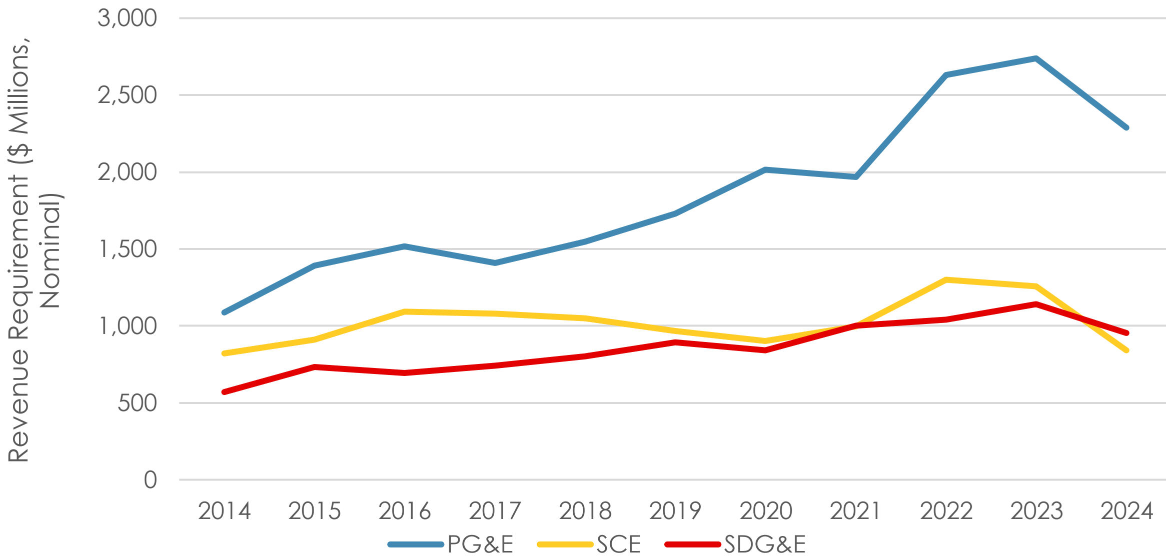
SDG&E's fifth formula rate case (TO5) was in effect from June 1, 2019 to December 31, 2024.[47] SDG&E's Total TRR in 2024 was $676 million, a 20.8 percent reduction from 2023's Total TRR of $854 million. The lower TRR can be attributed to a decline in the revenue requirement related to the 24-month total weighted forecast plant additions and a shift from an under-collection to an over-collection for the 2024 true-up.

The sum of negotiated settlements in over 20 rate case proceedings at FERC and the resulting estimated annual savings to California transmission ratepayers from the CPUC's advocacy in FERC TO rate cases since 2017 exceeds $5.4 billion.

Even with the savings for ratepayers secured by the CPUC's efforts, and the aforementioned downward TRR adjustments in 2024, transmission revenue requirements for the IOUs have been trending upward since 2014, increasing at an average annual growth rate of 6.7 percent for PG&E, 4 percent for SCE, and 8.4 percent for SDG&E as shown in **Figure 3.8**.

[47] SDG&E filed its new TO6 rate case on October 30, 2024, and it will take effect on June 1, 2025. It is in settlement discussions at the time of the publication of this report.

Figure 3.8: Trends in Total Transmission Revenue Requirements[48]



Historically, much of the increase in the utilities' revenue requirements was due to capital investments in transmission infrastructure. Significant portions of the IOUs' transmission rate bases include CAISO-approved reliability projects, as well as policy projects needed for meeting clean energy mandates. These CAISO-approved projects expand capacity of the grid, enabling interconnection of new electric generation, as well as compliance with North American Electric Reliability Corporation (NERC) requirements.

While there is substantial investment in CAISO approved projects, the current trend in transmission capital investment shows that all three IOUs are spending primarily on "self-approved" transmission projects. "Self-approved" means there is no existing requirement that these projects undergo formal review for cost or need by CAISO, CPUC, or any other third party during their planning and approval. Self-approved projects are not included in the CAISO's Transmission Planning Process because they do not expand the capacity of the transmission grid, and they are not transmission network upgrades included in CAISO-approved large generator interconnection agreements. These are repair and replacement projects needed for maintaining the grid, yet the lack of review raises uncertainty about whether these are the most cost-effective transmission projects, particularly as other work, like capacity expansion projects and upgrades, are subject to significant and costly delays. In data provided in the CPUC's Transmission Project Review (TPR) Process, the three electric utilities report that from 2020 to 2024, self-approved transmission projects accounted for $8.728 billion (74.8 percent) of their collective transmission spending of $11.665 billion, as

[48] The data represented in this graph are for the transmission owners' revenue requirements in rate cases at FERC. In 2023, this was $2,738,750,000 for PG&E, $1,258,480,000 for SCE, and $1,141,049,000 for SDG&E. Adding balancing account adjustments, the total transmission revenue requirements in 2023 were $3,272,496,000 for PG&E, $1,354,762,000 for SCE, and $860,184,000 for SDG&E.

shown in **Table 3.5**. More recently, large expenses such as administrative and general costs and operation and maintenance expenses have been increasing.

Table 3.5: Self-Approved Transmission Projects as a Share of Transmission Capital Investment

	2020-2024 ($M)
Total IOU Transmission Capital Projects	11,665
Self-Approved Capital Projects	8,728
Percentage of Self-Approved Projects	74.8%

Because FERC has determined that these self-approved projects do not fall under the transparent planning requirements of existing FERC regulations, the CPUC and other stakeholders found it necessary to negotiate PG&E's Stakeholder Transmission Asset Review (STAR) Process and SCE's Stakeholder Review Process (SRP) in their respective TO rate cases at FERC. While not binding in their effect, these stakeholder processes improved transparency of the two utilities' transmission capital projects.

Anticipating the expiration of the STAR Process and SRP at the end of 2023, the CPUC established the Transmission Project Review (TPR) Process in Resolution E-5252 in April 2023. The TPR Process began in January 2024, enhancing the level of data included in the STAR Process and SRP, and now including SDG&E. The TPR Process establishes uniformity of the data and opportunities for stakeholder engagement. While these stakeholder processes are important for ensuring that the IOUs are building the right projects for safety and reliability, they occur downstream from transmission planning and approval. In recent years, Energy Division's FERC Cost Recovery Section has been playing a significant role in FERC rulemakings and technical conferences, as well as supporting CPUC Commissioners between 2021 and 2024 in their role on FERC's Joint Federal-State Task Force on Electric Transmission, with any eye on ensuring that the substantial buildout of the transmission system in years to come is planned and implemented most efficiently and cost-effectively.

IV. Power Procurement Costs

The generation revenue requirement includes utility owned (or retained) generation (UOG) costs, as well as purchased energy and capacity costs. As previously noted, in the late 1990s the utilities divested almost all of their fossil-fueled generating plants during restructuring, and, as a result, they largely rely on purchased power for incremental electricity needs.

In 2024, purchased power accounted for approximately 54 percent of the total generation revenue requirement (see **Table 4.1**). Power purchase costs represented the largest component of forecasted generation costs and accounted for 16 percent of total revenue requirements (see **Table 4.1**). Recovery of these pass-through costs is authorized through the ERRA proceedings. The sale of purchased power is expensed, not capitalized.

Table 4.1: Percentage of Generation Costs and Total Revenue Requirement Related to Purchased Power

Revenue Requirement	Amount ($000)	Purchased Power Portion
Purchased Power	6,649,743	
Total Generation	12,310,230	54%
Total Revenue Requirement	42,104,374	16%

Background

Heavy reliance on power purchases rather than UOG began with the enactment of AB 1890 in 1996, which restructured the electric utility industry in California and created the CAISO and the Power Exchange. After the energy crisis in 2000-2001, the Power Exchange was closed and the CAISO assumed control of day ahead and real time energy markets, subject to FERC jurisdiction. To create a competitive electricity market in which non-utility suppliers would compete with the utilities in the wholesale generation market to provide direct access to power plants to customers, the utilities were encouraged to divest at least 50 percent of their fossil-fueled generation. The CPUC provided a rate of return (ROR) incentive to the utilities to encourage them to divest and allowed for the recovery of stranded assets over a period of time with a "competition transition charge" (CTC). As a result of the statutorily mandated requirement to recover stranded costs as part of the electric restructuring legislative package, the utilities sold a substantial portion of their fossil-fueled generation.

Prior to AB 1890, the IOUs provided retail electric service to all customers under regulation from the CPUC. AB 1890 opened Direct Access to both residential and non-residential customers, allowing customers to purchase electricity directly from third- party Energy Service Providers (ESP) while the IOUs continued to supply the transmission and distribution services needed to transport power to the customer.

During the energy crisis, the utilities were exposed to high market prices for electricity, due in large part to the divestiture of their generating plants, who then bid the plants back into the power exchange at high prices. Authorized utility rates, which were frozen at pre-restructuring levels from June 1996 as part of the legislative restructuring package, were insufficient for the utilities to cover the high costs of purchased power. PG&E filed for bankruptcy and both SCE and SDG&E faced substantial financial uncertainty. In response, the Legislature enacted AB X1 (Keeley and Migden, 2001), which authorized the DWR to enter into power purchase contracts to stabilize the severely disrupted energy markets. AB X1 also suspended customer enrollment in Direct Access.

In 2002, the Legislature enacted AB 57 (Wright, 2002) to return energy procurement responsibilities to the utilities. The legislature required the CPUC to establish upfront reasonableness standards for bundled procurement to avoid the need for after the fact reasonableness review. As a result, the CPUC adopts Short-Term Procurement Plans to ensure sufficient resource availability over time- later these plans would be known as Bundled Procurement Plans. The legislation also established guidelines for procurement solicitations, cost recovery of power purchases, and integration of renewable resources using long-term planning. The contracts resulting from these solicitations are reviewed by Procurement Review Groups[49] that the CPUC required the IOUs to create. The costs associated with bundled procurement are tracked in the ERRA proceedings. Once the procurement markets stabilized after the energy crisis, the CPUC required the utilities to conduct Long-Term Procurement Plans, a predecessor to what is now handled in the Integrated Resource Plan proceeding.

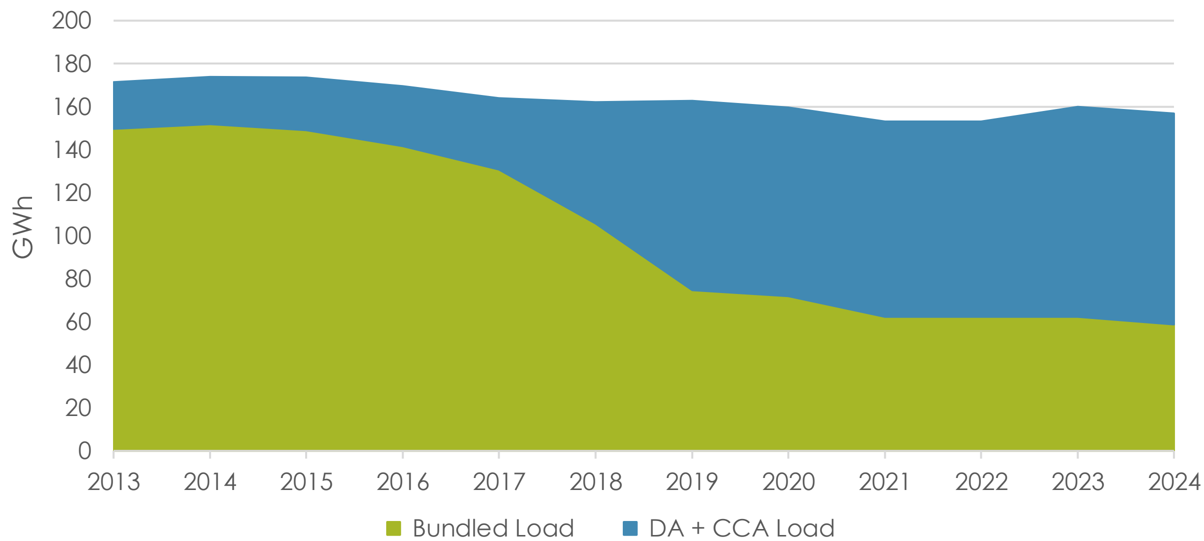
AB 380 (Nunez, 2005) further addressed CPUC responsibilities for resource planning, requiring the CPUC, in consultation with the CAISO, to establish resource adequacy requirements to ensure that adequate physical generating capacity would be available to meet peak demand. Consequently, the utilities (and all load serving entities) are required to procure capacity to maintain a planning reserve margin for generating capacity. Known as the resource adequacy (RA) program, the CPUC RA requirements ensure that the CAISO daily energy markets are offered sufficient capacity to serve forecasted load. The RA program is a critical part of the CPUC's reliability framework, but it also serves to moderate generation costs by reducing the likelihood of capacity scarcity events which can cause price spikes that are passed on to customers.

In 2002, AB 117 (Migden, 2002) established PU Code Section 331.1, which authorizes the implementation of Community Choice Aggregation. AB 117 allows local government entities to form CCAs to purchase power for their communities from non-utility power suppliers. Per AB 117, customers are defaulted into CCA service when a CCA is formed in their service area, with an option to opt-out and return to utility service. Additionally, SB 695 (Kehoe, 2009) opened Direct Access to a limited amount of new non-residential load but set a cap on enrollment at roughly 13 percent of peak load. SB 237 (Hertzberg, 2018) increased the cap by an additional 4,000 GWh. As a result of these policies, IOU load has dropped by 46

[49] A CPUC authorized forum that reviews procurement activities including contracts and reasonableness criteria and offers assessments and recommendations to each utility. The CPUC initially established Procurement Review Groups (PRG) in D.02-08-071 as an advisory group to assess the IOUs' procurement strategy and processes, and specific proposed procurement contracts. The PRG includes non-market participants, and Energy Division and Cal Advocates.

percent since its peak in 2011, due to load migration from IOUs to CCA and ESP service. This steep decline is clearly evident in **Figure 4.1** below.

Figure 4.1: PG&E Load Share Over Time



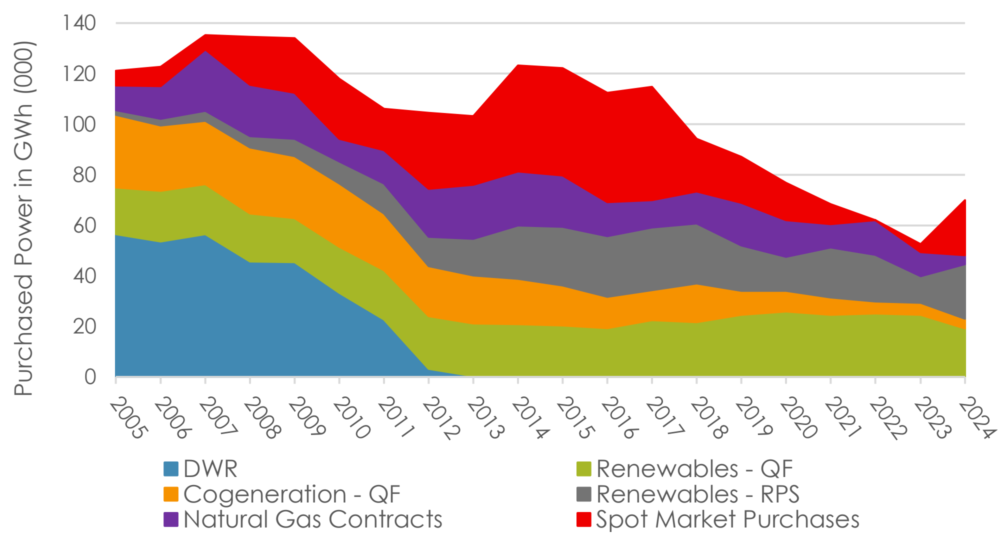
In addition, SB 1078 (Sher, 2002) established the RPS Program and required the utilities to serve 20 percent of their electricity demand with renewable resources by 2017. The statute also required each IOU to hold an annual solicitation to procure renewable power. SB 107 (Simitian and Perata, 2006) later increased the RPS obligation to 20 percent by 2010 and was updated by SB 2 (Simitian, 2011) when the RPS obligation was raised to 33 percent by 2020. SB 350 (de León, 2015) raised the RPS obligation to 50 percent by 2030. In 2018, SB 100 (de León, 2018) set the current RPS obligation to 60 percent by 2030 and the planning goal of obtaining 100 percent of electric retail sales to end-use customers from renewable energy and zero-carbon resources by 2045. Additionally, in 2022, SB 1020 (Laird, Atkins, Caballero, and Durazo, 2022) established a 90 percent clean energy requirement in 2035, a 95 percent clean energy requirement in 2040, and clarified that eligible renewable energy resources and zero-carbon resources should supply 100 percent of all retail sales of electricity to California end-use customers by December 31, 2045, and 100 percent of electricity procured to serve all state agencies by December 31, 2035.

Purchased Power

The amount of load served by direct access providers was frozen around 12 percent during the energy crisis. However, since 2005, IOU purchased power supply has decreased over time due to the migration of load from the IOUs to CCAs, which reduced the IOUs' demand. Since the first CCA, Marin Clean Energy, formed in 2009, 38 percent of total load has departed the IOU to be served by CCAs. As a result, the revenue requirement to serve the IOUs has decreased from $12.68 billion in 2009 to $8.1 billion in 2023.

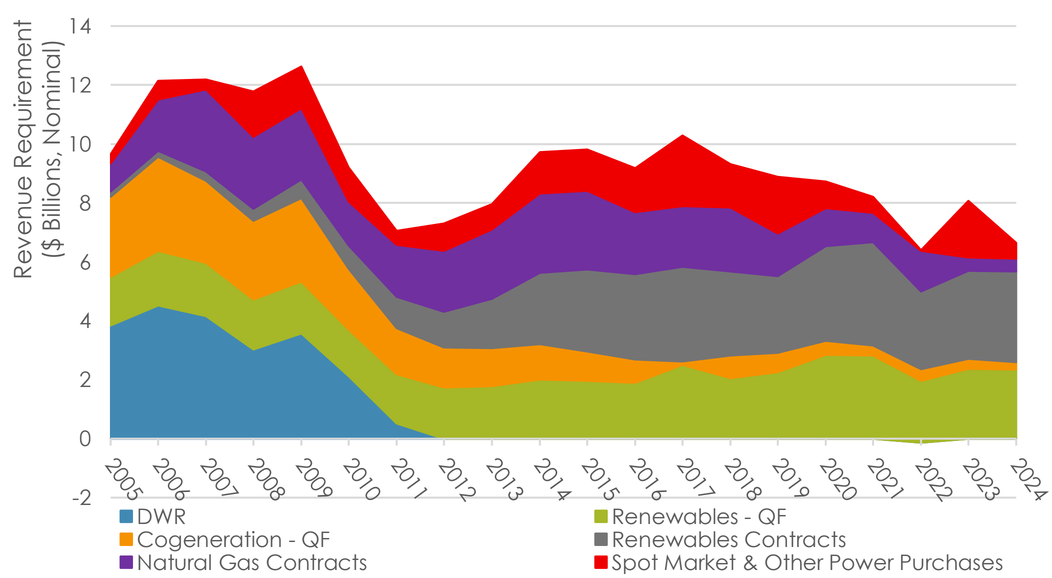
Figure 4.2 and **Figure 4.3** break out purchased power supply and revenue requirements. From 2018-2023, the IOUs have decreasingly relied on energy procurement through the CAISO energy market, but spot market purchases increased from 6 percent to 31 percent of the power purchased in 2024.

Figure 4.2: Trends in Purchased Power Supply (GWh)



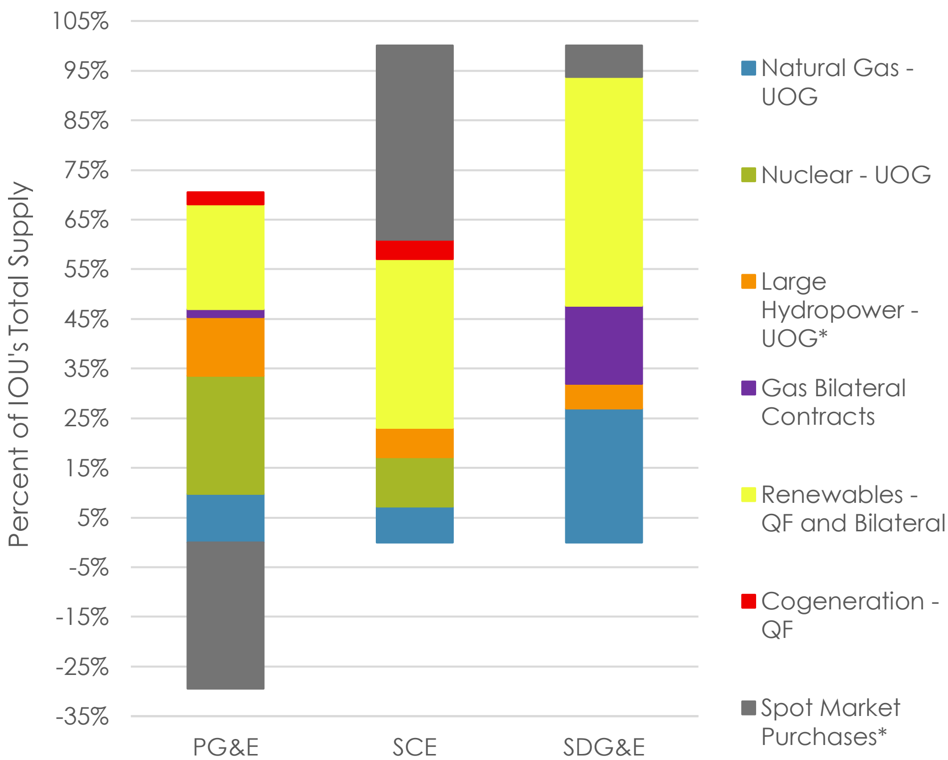
While total purchased power supply has decreased by 56 percent since 2005, the revenue requirement for purchased power has only decreased by 16 percent. This indicates that the average cost / KWh has increased significantly from 2005 to 2024.

Figure 4.3: Trends in Purchased Power Revenue Requirement



Types of Purchased Power

Figure 4.4: 2024 Forecast Energy Supply for Electric Utilities



*Spot Market Purchases includes sales of surplus energy and inter-utility and other purchased power sources. Large Hydropower – UOG includes

Department of Water Resources (DWR) Contracts

The California Department of Water Resources (DWR) entered into long-term contracts on behalf of IOU customers during the energy crisis. Each year, DWR submitted its revenue requirement to the CPUC for adoption and subsequent collection from, or refund to, ratepayers through the DWR Power Charge. Due to the recent expiration of these contracts, DWR's Power Charge revenue requirement for all three utilities was zero. In the coming years, proceeds from CPUC ongoing litigation related to these contracts is possible and if realized, will result in future refunds to customers.

Qualifying Facilities (QFs)

Qualifying Facilities (QFs) are co-generation and renewable generation facilities that qualify to sell power to the utilities under the Federal Public Utility Regulatory Policies Act (PURPA). These facilities must meet FERC's requirements for ownership, size, and efficiency to qualify as QFs. PURPA requires IOUs to interconnect with, and purchase power from, QFs at rates that reflect costs the utility avoids by buying QF power instead of procuring power from other sources. In 2011, the CPUC approved the QF/Combined Heat and Power (CHP) Program Settlement which suspends the "must-take" obligation for QFs over 20 MW and establishes new energy prices for QFs. In 2015, the CPUC added an Emissions Reduction Target associated with CHP procurement of 2.72 million metric tons of greenhouse gas (GHG) emissions reductions by 2020.[50] The Settlement ended in 2020, with SDG&E required to an additional CHP solicitation in 2022 to meet its obligations under the Settlement.[51] In 2020, the CPUC adopted a new Standard Offer Contract (SOC) for QFs, including new avoided cost energy and capacity prices established either at time of contract execution or at time of product delivery.[52] In 2022, the CPUC modified the SOC to allow for storage-paired QFs.[53]

Bilateral Natural Gas Contracts

Bilateral contracts are contracts entered into directly between a utility and an independent power supplier – either a generator or trader – and are generally sourced by the utilities through a Request for Offers (RFO) open solicitation process. Bilateral contracts can include capacity and energy, usually in the form of a tolling arrangement, or they can be capacity only contracts. Capacity contracts pay generators to be available to produce power and ensure that sufficient capacity is available to meet load.

Renewable Energy Procurement

The CPUC annually produces a report, Costs and Cost Savings on the RPS Program, pursuant to PU Code 913.3. The report describes the costs of renewable energy procurement across a variety of metrics.

Building on over a decade of RPS legislation, SB 100 requires retail sellers to meet a 60 percent RPS procurement requirement by 2030. D.19-06-023 established that for Compliance Period 2021-2024, retail sellers must procure no less than 44 percent of their retail sales from eligible renewable energy resources by December 31, 2024, and procure no less than the quantities calculated by the straight-line trend method in the intervening years through 2030 as required by SB 100.[54]

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[50] CPUC D.15-06-028, issued on June 15, 2015.

[51] CPUC Resolution E-5163, issued on August 20, 2021.

[52] CPUC D.20-05-006, issued on May 15, 2020.

[53] CPUC D.22-06-003, issued on June 10, 2022.

[54] D.19-06-023 at Ordering Paragraph (OP) 1.

The IOUs are currently on track to meet their 60 percent by 2030 RPS requirements through their procurement of renewables generation and use of their prior excess procurement of renewable energy or "banked" renewable energy credits (RECs). In addition to banking excess RECs, for the past several years the IOUs have sold small quantities of their excess REC supply and allocated or sold portions of their RPS portfolios through the Voluntary Allocation and Market Offer (VAMO) process and credited the revenue from these transactions to ratepayers. The three large electric IOUs report RPS progress at or above the program procurement requirements for Compliance Period 2021-2024. After accounting for the sale of excess RECs and voluntary allocations, the IOUs served 49.7 percent of their electricity demand with RPS eligible resources in 2024. For 2024, the IOUs were forecasting that 44 percent of PG&E's load,[55] 48.7 percent of SCE's load,[56] and 46.9 percent of SDG&E's load[57] were met by RPS-eligible resources.[58]

The large IOUs' total annual RPS procurement expenditures increased from $5.0 billion in 2023 to $5.3 billion in 2024, while total renewables generation also increased from 48,662 GWh to 49,693 GWh, partly as a result of increasing RPS percentages.

The large IOUs' average procurement expenditure for all RPS contracts online slightly increased in real dollar value to 10.5 cents per kilowatt-hour (¢/kWh) in 2024 compared to 10.0 cents per kilowatt-hour (¢/kWh) in 2023. This reflects an increase in renewables' costs on a per kWh basis. These costs included energy, capacity, and RECs procured through RPS contracts. Additionally, the average cost for non-RPS energy in 2024 declined slightly to 7.1 ¢/kWh from 8.3 ¢/kWh in 2023. This represents a 3.4 ¢/kWh cost premium for their average RPS procurement expenditure compared to their average non-RPS procurement expenditure.

The average price of RPS contracts that were executed in 2024 was higher at 8.1 ¢/kWh compared to 5.9 ¢/kWh in real dollars in 2023. Cost drivers may include the increase in demand as well as constraints on certain parts of the supply chain given an uncertain regulatory and economic climate.

Figure 4.5 below summarizes the large IOUs' actual and forecasted progress toward meeting the 60 percent RPS mandate by 2030.

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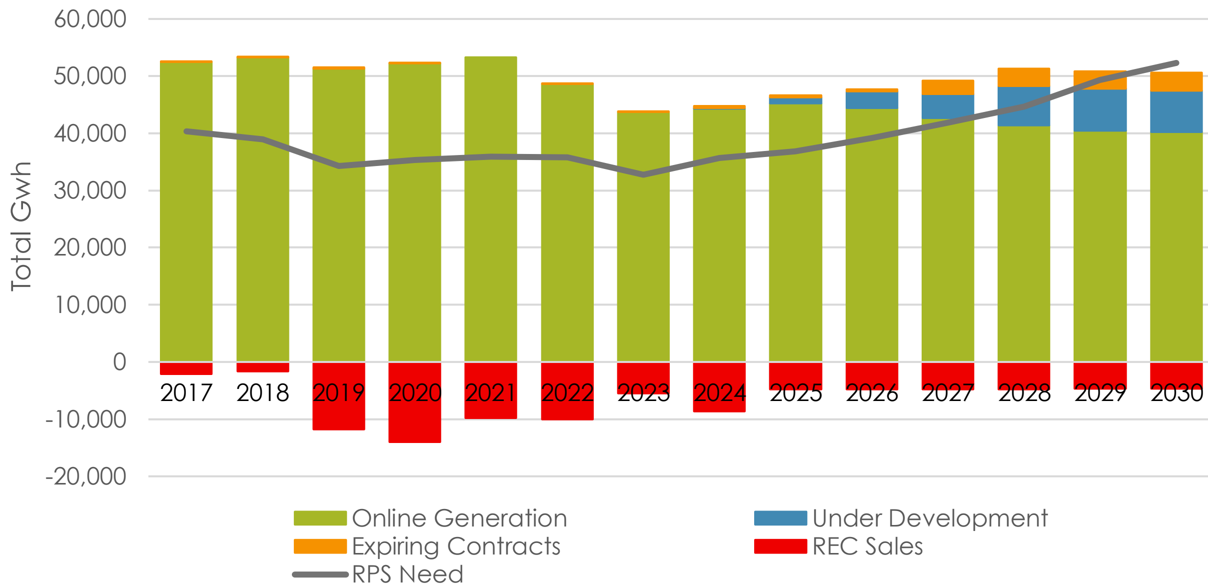
[55] PG&E Final 2024 RPS Plan at Appendix C.1.

[56] SCE Final 2024 RPS Plan at Appendix C.1.

[57] SDG&E Final 2024 RPS Plan at Appendix 1a.

[58] These percentages were forecasted by the IOUs in July 2024, during the filing of the 2024 Procurement Plans.

Figure 4.5: Aggregated IOU Progress Toward 60 Percent RPS[59]



All three IOUs have been granted the authority to hold long-term RPS solicitations to procure RPS resources to meet their RPS requirements in a least-cost, best-fit manner.

Other Power Purchases

Additional power purchase and sale mechanisms exist to ensure that the utilities secure sufficient capacity to balance load across the grid and meet peak load requirements at least cost.

- **Spot Market Purchases:** This term refers broadly to power that the utilities buy from the CAISO's Day-Ahead market to balance the system on a day-to-day basis. IOUs use the spot market to balance their forecasted load requirements for the following day through transactions that may occur in the CAISO market.
- **Net Long Sales:** These are sales that the utilities make when their expected supply exceeds their forecasted load and may occur in the spot market or other timeframes. These sales reduce ratepayer costs by generating revenue from excess capacity not likely to be needed.
- **Inter-Utility or Power Exchange Agreements:** Traditionally, regulated utilities enter into seasonal and long-term inter-utility exchange agreements with other regulated utilities and other load serving entities. Through bilateral negotiations the specific terms are crafted to best fit the resources and needs of both parties. Payment is typically in the form of non-cash exchanges of capacity and energy balanced

[59] Source: CPUC 2024 RPS Annual Report (November 2024)

to reflect the seasonal and locational value of the power. Different peaking times in the northwest and southwest lead to large-scale transactions.

- **Real-Time Market and Reliability Services:** The CAISO has certain agreements with generators to provide reliability services. The CAISO spreads the costs of these reliability services among the load serving entities. In addition, the CAISO buys power in the real-time market to balance resources and loads and charges the load serving entities whose short supply necessitated real-time purchases.

Greenhouse Gas Costs and Allowance Proceeds

Since January 1, 2013, electric utilities have been regulated under California's Greenhouse Gas Cap-and-Trade Program. As covered entities under the program, the electric utilities must secure compliance instruments, known as offsets and allowances, and surrender them to the California Air Resources Board (CARB) to account for their GHG emissions. CARB holds quarterly allowance auctions where entities can buy and sell allowances. Utilities can also procure compliance instruments on secondary markets or through contractual arrangements.

The Cap-and-Trade Program requires the utilities to comply on their customers' behalf for the emissions associated with the energy customers use. For electric utilities, compliance costs come in the form of a direct compliance obligation for utility-owned generators and generators under contract (which must also buy and surrender compliance instruments), as well as indirect costs from wholesale market transactions or power contracts with pricing terms that include GHG emission costs.

Beginning in 2014, the electric utilities introduced Cap-and-Trade Program related costs into electricity rates and began distributing allowance proceeds to residential customers via the California Climate Credit, applied to customer bills twice a year. Small Business customers and emissions-intensive trade-exposed industrial customers also began to receive credits in 2014.

Overall, including both indirect and direct costs, credits from the Cap-and-Trade Program are expected to offset any cost increases for residential electric customers.[60] Utilities accrue costs for the Cap-and-Trade Program as both direct and indirect costs. In 2024, the electric utilities collectively included approximately $202 million in direct GHG costs into rates to bundled customers and returned approximately $1.14 billion in allowance proceeds to bundled customers in the form of customer credits (see **Table 4.2**). The electric utilities also returned approximately $752 million in allowance proceeds to unbundled customers in customer credits. Customers also incur indirect costs for the Cap-and-Trade Program when utilities purchase power from the spot market or other market purchases, where the cost of compliance is included as part of the purchase price. These Cap-and-Trade Program compliance costs are included in the "Purchased Power" row of **Table 2.1** (2024 Electric IOU Authorized Revenue Requirements) but are not reported separately in this section.

[60] Legislative Analyst's Office (LAO). Cap-and-Trade: Overview and Affordability Considerations. February 26,2025. https://lao.ca.gov/handouts/resources/2025/Cap-and-Trade-Overview-and%20Affordability-022625.pdf

Table 4.2: 2024 Summary of Greenhouse Gas Costs and Allowance Proceeds[61]

Utility	2024 Electric GHG Direct Costs Revenue Requirement[62]	2024 Electric Proceeds Distributed to Bundled Customers	2024 Electric Proceeds Distributed to Unbundled Customers
PG&E		$312,677,354	$377,263,494
SCE		$738,929,774	$218,327,684
SDG&E		$86,262,445	$156,844,867
Total	**$202,058,826**	**$1,137,869,573**	**$752,436,045**

Each year, CARB allocates allowances to electric utilities on behalf of their ratepayers. The Cap-and-Trade Program requires the three electric IOUs to sell all of the allocated allowances at CARB's quarterly allowance auctions in the year they are allocated. The proceeds the utilities receive from the sale of GHG allowances must be used exclusively for ratepayer benefits, consistent with the goals of AB 32 (Nunez and Pavley, 2006), CARB regulations, and as directed by the CPUC. Consistent with the direction in SB 1018 (Committee, 2012), the CPUC has determined the methodologies the utilities should use to return proceeds to industrial customers,[63] small businesses, and residential customers.

In addition to customer credits, up to 15 percent of allowance proceeds may be used for clean energy or energy efficiency programs. AB 693 (Eggman, 2015) directed up to $100 million of allowance proceeds to be allocated annually to solar energy systems in disadvantaged communities. In response, the CPUC established the Solar on Multifamily Affordable Housing (SOMAH) program in December 2017. In 2020, the CPUC determined that as proceeds are available and there is adequate participation and interest in SOMAH program, allocation of funds to the SOMAH program will continue through June 30, 2026.

For the fourth consecutive year, in 2024 SOMAH was funded at the full $100 million ceiling. Prior-year allocations were also trued up, which resulted in a net of $69 million in 2024 allocated allowance auction proceeds being directed toward SOMAH. In 2018, in response to AB 327 (Perea, 2013), the CPUC developed the Disadvantaged Communities Single-family Solar Homes program (DAC--SASH), the Community Solar Green Tariff (CSGT), and Disadvantaged Communities-Green Tariff (DAC-GT) programs to encourage growth of renewable generation among residential customers in disadvantaged communities.[64] DAC-GT and CSGT above-market generation costs are funded with allowance proceeds

[61] Proceeds recorded through September 30, 2024 and estimated through December 31, 2024. Costs recorded through July 31, 2024 and estimated through December 31, 2024 for SCE; forecast for PG&E and SDG&E. Costs for bundled customers only. Bundled proceeds include residential and small business California Climate credits and CA Industry Assistance.

[62] Due to confidentiality, some cells have cost values that were redacted.

[63] Defined as emissions-intensive and trade-exposed by Public Utilities Code section 748.5.

[64] The DAC-SASH program is funded up to $10 million annually, and funding is provided as needed and available for the CSGT and DAC-GT programs.

and the 20 percent customer discount, program administration, and marketing, education, and outreach costs are funded through public purpose programs (PPP) funds.

Table 4.3: 2024 Electric Allocated Allowance Proceeds to Programs

Program	Allocated Allowance Proceeds in 2024
SOMAH[65]	$69,468,360
DAC-SASH	$10,065,000
DAC-GT & CSGT	$725,567
Total	**$80,258,927**

Other Factors Affecting Electricity Generation Costs

Prior sections have described many factors that cause energy generation and procurement costs to vary significantly between different types of procurement and through time. Natural gas prices, capacity prices, and weather are other factors that have historically had a significant effect on the cost of many types of generation.

- **Natural Gas Prices:** Natural gas prices cause gas-fired generation costs to be more volatile than other forms of generation. Gas-fired electric generators are particularly exposed to volatility in the gas spot market when they do not hold long-term, firm contracts for natural gas or do not have access to gas storage. Electric spot market purchases and cogeneration Qualifying Facilities' costs fluctuate and track with gas prices. Natural gas bilateral contracts do not track as closely with gas prices, as most of those contract costs are associated with capacity and not energy. Renewables contracts generally exhibit more cost stability because they are not reliant on gas prices. Some IOU contracts for tolling agreements with gas plants also require purchase of natural gas to burn in the natural gas generators, and some natural gas hedging contracts are part of the IOU electricity portfolio to insure against spikes in natural gas prices causing electricity price spikes.
- **Resource Adequacy Capacity Prices:** Capacity prices affect the costs of generation. These prices are driven by capacity market conditions which reflect the balance of supply and demand. Scarcity in the market can cause prices to increase. Capacity prices for new resources are also sensitive to supply chains, changes to tax laws (e.g., Inflation Reduction Act tax credits), and interconnection delays which can also have significant impacts on costs.
- **Weather**: Weather continues to play a role in varying electricity prices. For example, the summer heat waves in 2020 and 2022 throughout California caused electricity prices to spike to extreme highs during peak demand hours. In addition, droughts can affect hydro availability and increase reliance on natural

[65] SOMAH includes prior-year 2023 true-up.

gas-fired generation; all else equal, this tends to increase electricity prices. Cold weather, such as occurred in winter 2022-2023, also contributed to an increase in natural gas and electricity prices during that time.

- **Proxy Valuation of Power Charge Indifference Adjustment (PCIA) Eligible Resources:** The CPUC has adopted a PCIA process to keep bundled customers indifferent towards departing load. The PCIA gives a credit to either bundled customers or departing load based on the valuation of the portfolio of eligible resources contracted prior to the load's departure. The CPUC launched an Order Instituting Rulemaking (OIR) in 2025 to review the methodology to calculate the proxy PCIA benchmark. In the staff report in the OIR, staff explained that in the years with low transaction volumes, current PCIA benchmark calculations are subject to outlier transactions skewing the assigned proxy value of a resource, at times making the resource more valuable than its contract cost. This phenomenon artificially raises the cost of scarce RA capacity resources and may have other distortionary impacts on rates.
- **Remediation of Extraordinary Procurement Costs:** Each of the electric IOUs collects generation rates based on an ERRA Forecast application. If generation costs are significantly higher or lower than forecasted, the affected utility must file an ERRA Trigger notification with the CPUC. If the utility does not believe that the difference will be within the authorized threshold within 120 days, it files an expedited ERRA Trigger Application that corrects rates to be in line with the costs the utility is experiencing. The ERRA Trigger Application process supports long-term rate stability if the costs associated with fuel and purchased power vary greatly from forecasted amounts.

The CPUC conducts annual ERRA Compliance reviews that true-up any difference from each of the utilities' ERRA Forecast revenue requirement to the actual costs incurred, regardless of whether an ERRA Trigger application was filed.

Variances in electric generation and procurement costs due to weather are addressed in the CPUC's annual ERRA Compliance and ERRA Forecast applications, as well as mid-year ERRA Trigger adjustments when warranted by particularly large electric price deviations from forecasts.

The price of natural gas in California reached sustained highs during winter 2022- 2023 due to lower gas storage levels on the West Coast, pipeline outages, reduced supply and cold temperatures. In contrast, gas prices during winter 2023-2024 and 2024-2025 have been modest due to higher storage inventories, no major pipeline outages and milder weather. The gas price spikes caused SCE and PG&E to file ERRA Trigger applications.

V. Demand-Side Management and Customer Programs

The Demand-Side Management (DSM) initiatives overseen by the CPUC encompass a mix of energy efficiency (EE), demand response (DR), and distributed generation (DG) programs, serving all sectors of California's economy. For nearly half a century, the CPUC has implemented policies to promote energy conservation, efficiency, and load management.

In 2003, the CPUC and the California Energy Commission (CEC) adopted the Energy Action Plan to establish goals for the state's energy strategy. The plan prioritized cost-effective energy efficiency and demand response at the top of the loading order, making them the preferred methods for meeting the state's growing energy needs, followed by renewable energy and distributed generation. Only after meeting all load needs with preferred resources, then the State used efficient natural gas generation to meet demand.

California has led the nation in customer-side solar and other distributed generation technology market growth, subsidized by IOU ratepayers through the net energy metering (NEM) and net billing tariffs, first established in 1996 and 2023, respectively. The Self-Generation Incentive Program (SGIP), enacted in 2000, and the landmark California Solar Initiative (CSI) program, introduced in 2006 by SB X1 (Murray, 2006), also provided IOU ratepayer funds to support this growth; both programs are overseen by the CPUC.

For decades, the CPUC has administered low-income energy efficiency (EE) programs—now called Energy Savings Assistance (ESA)—to help vulnerable populations manage their energy bills. The CPUC also receives input on these and other programs from the Low-Income Oversight Board (LIOB), which was established by the Legislature in 2001.

The CPUC continues to advance DSM initiatives to enhance energy efficiency, demand response, and distributed generation across the state. Recent developments include:

- **Demand Flexibility Rulemaking (R.22-07-005):** Initiated on July 14, 2022, this rulemaking aims to promote demand flexibility through electric rates. It seeks to update rate design principles, reform demand charges, and develop policies and programs that encourage voluntary demand flexibility among consumers.
- **Integrated Demand-Side Management (IDSM):** The CPUC requires utilities to integrate customer demand-side programs, such as energy efficiency, self-generation, advanced metering, and demand response, to operate more coherently and efficiently. Program administrators were required to submit Tier 3 advice letters by March 15, 2024, for programs to be launched during the 2024-2027 portfolio period.
- **Demand Response (DR) Initiatives:** The CPUC defines demand response as adjustments in electricity consumption by customers in response to economic or reliability signals. This includes reducing, increasing, or shifting usage to support grid stability and efficiency.
- **Distributed Energy Resources (DER) Cost-Effectiveness:** On August 8, 2023, the CPUC's Energy Division issued a staff proposal for 2024 updates to the Avoided Cost Calculator (ACC) - a tool used to

assess the cost-effectiveness of DERs - through a ruling by an administrative law judge. The updated 2024 ACC was formally adopted through Resolution E-5328 on November 7, 2024. This resolution establishes an integrated methodology for calculating generation capacity and greenhouse gas avoided costs and updates the planning baseline to align with the state's resource planning framework.

These initiatives reflect the CPUC's ongoing commitment to enhancing DSM strategies, promoting energy efficiency, and supporting the integration of renewable energy sources to meet California's evolving energy needs.

Table 5.1 shows the DSM and customer program costs recovered in rates.

Table 5.1: 2024 Demand Side Management and Customer Programs Costs ($000)[66]

Program	PG&E	SCE	SDG&E	Total
Energy Efficiency[67]	182,850	288,997	(31,000)	**440,846**
Demand Response	197,659	49,299	10,713	**257,671**
Self-Generation Incentive Program	59,877	56,626	22,022	**138,526**
Electric Program Investment Charge	99,681	76,885	16,280	**192,846**
California Alternative Rates for Energy Administration	(12,144)	64,318	6,242	**58,416**
Energy Savings Assistance	(7,595)	92,018	16,389	**100,812**
Other PPP Programs[68]	320,291	87,730	343,346	**751,367**
Other Regulatory	(27,664)	322,563	224,980	**519,879**
Total	**812,954**	**1,038,436**	**608,973**	**2,460,363**

[66] Revenue requirements for certain programs, such as Demand Response, are collected through the distribution rate component.

[67] The collection amounts for Energy Efficiency will not necessarily match spending amounts shown in Table 5.2, primarily because IOUs collect funds from ratepayers based on authorized budgets, regardless of actual expenditures.

[68] Programs included in the Other PPP Programs category vary for each utility. The largest program costs are from the Residential Uncollectibles Balancing Account for PG&E, the Public Purpose Programs Adjustment Mechanism (PPPAM) for SCE, and the California Alternative Rates for Energy (CARE) program for SDG&E (distinct from CARE administration costs shown elsewhere in the table).

Energy Efficiency

In 2003, the California Energy Action Plan placed energy efficiency at the top of the loading order, emphasizing that the state should maximize all cost-effective energy efficiency investments in both the short and long term. In D.04-09-060, the CPUC translated this policy into specific annual and cumulative numerical goals for electricity and natural gas savings by utility service territory. These goals are periodically updated as outlined in that Decision.

The CPUC-adopted energy savings goals are measured in annual and cumulative gigawatt hours (GWh), million therms (MMtherms), and peak megawatt (MW) load reductions. Notably, in D.21-05-031, the CPUC introduced a new single metric, the Total System Benefit (TSB), which quantifies the lifecycle energy, capacity, and greenhouse gas (GHG) benefits in dollar terms on an annual basis. As of 2024, the TSB metric has replaced kWh, kW, and therm savings as the primary goal for energy efficiency portfolios.

The gas portion of the energy efficiency portfolios is funded through the gas Public Purpose Program (PPP) component of utility rates. The electric portion is funded through the Procurement Energy Efficiency Balancing Account (PEEBA), which accounts for the avoided costs of electricity generation, transmission, and distribution upgrades resulting from reduced electricity demand. The total aggregated expenditures for 2023 and 2024 amount to approximately $987 million with $449 million and $537 million spent in 2023 and 2024, respectively (see **Table 5.2**). It is worth noting that the collection amount for energy efficiency, as shown in **Table 5.1**, does not necessarily match the spending amount for the same IOU in the same year. This is primarily because IOUs collect funds from ratepayers based on their CPUC-authorized budgets, regardless of actual expenditures. When an IOU does not spend its full authorized energy efficiency budget, several outcomes are possible depending on CPUC directives. These may include:

- **Carryover or Rollover:** Unspent funds may be carried over to the next program year for continued or future use.
- **Return to Ratepayers:** CPUC may direct IOUs to return unused funds to ratepayers, typically through rate adjustments or balancing accounts.
- **Impact on Future Collections:** If IOUs consistently underspend, the CPUC may reduce future authorized budgets, thereby lowering rate collections accordingly.

Programmatic efforts in 2023 and the first three quarters of 2024 resulted in reported energy savings of $1,216 million in Total System Benefit (1,137 GWh, 193 MW, and 118 MMtherms). According to the EPA, these electricity savings are equivalent to the CO_2 emissions from the annual electricity use of approximately 93,245 homes. Meanwhile, the gas savings are equivalent to avoiding CO_2 emissions from about 16 percent of a coal power plant's annual emissions.

These programs support the residential, public, commercial, industrial, and agricultural sectors in overcoming barriers to improving energy efficiency and achieving savings for ratepayers. In addition to the directly quantifiable savings and benefits, the CPUC has also supported programmatic activities aimed at the long-term transformation of consumer energy markets. These efforts include emerging technology development, marketing, education, training, and other initiatives. However, the savings benefits associated with these efforts are difficult to quantify, and the CPUC has historically not attempted to do so.

Table 5.2: Energy Efficiency Savings and Expenditures from Non-Codes and Standards IOU Programs ($000)[69]

All Investor-Owned Utilities	2024	2023	Grand Total[70]
Total System Benefit	**720,178**	**495,484**	**1,215,661**
Electric (GWh)	**481**	**656**	**1,137**
Demand (MW)	**88**	**105**	**193**
Natural Gas (MMTh)	**69**	**49**	**118**
Carbon (1000 Tons CO2)	**528**	**458**	**986**
Total Expenditures	**537,070**	**449,447**	**986,517**
PG&E			
Total System Benefit	349,511	210,642	**560,153**
Electric (GWh)	373	382	**755**
Demand (MW)	72	73	**145**
Natural Gas (MMTh)	34	20	**54**
Carbon (1000 Tons CO2)	309	219	**528**
Total Expenditures	167,121	170,279	**337,400**

[69] 2024 data includes Q4, but the IOUs' complete dataset may not be available until the final annual report is released on June 30, 2025, to ensure completeness. Savings data does not include REN/CCAs or Codes and Standards advocacy savings; savings data is reported net, first-year savings; decimals have been rounded to the nearest whole number; IOU expenditures are reported at the program level and are not broken down into gas vs. electric expenditures.

The savings and expenditures reported here are Program Administrator (PA) claimed values, representing initial estimates submitted prior to independent evaluation. These figures are subject to change based on Evaluation, Measurement, and Verification (EM&V) activities, which may include verification of measure installation, energy use measurement, engineering analysis, impact and net-to-gross evaluations, and process assessments. EM&V helps ensure the accuracy of reported outcomes and informs future program improvements.

[70] Totals are summed before rounding, then rounded to the nearest whole number.

All Investor-Owned Utilities	2024	2023	Grand Total[70]
SCE			
Total System Benefit	111,217	68,586	**179,803**
Electric (GWh)	78	216	**294**
Demand (MW)	12	21	**32**
Natural Gas (MMTh)	6	0	**6**
Carbon (1000 Tons CO2)	59	53	**112**
Total Expenditures	191,791	127,884	**319,675**
SoCalGas			
Total System Benefit	220,487	178,341	**398,828**
Electric (GWh)	5	6	**12**
Demand (MW)	4	2	**6**
Natural Gas (MMTh)	24	26	**51**
Carbon (1000 Tons CO2)	131	159	**290**
Total Expenditures	122,531	97,955	**220,486**
SDG&E			
Total System Benefit	38,962	37,914	**76,876**
Electric (GWh)	25	52	**77**
Demand (MW)	1	9	**10**
Natural Gas (MMTh)	4	3	**6**
Carbon (1000 Tons CO2)	29	27	**56**
Total Expenditures	55,627	53,329	**108,956**

Demand Response

If designed well, demand response programs can provide California ratepayers with various economic and environmental benefits, such as:

- Lowering energy costs by avoiding the purchase of high-priced energy and reducing market price volatility.
- Deferring or avoiding capital expenditures to build power plants and transmission and distribution infrastructure that would otherwise be necessary to meet peak demand.
- Enabling integration of intermittent renewable resources.
- Providing greater reliability to the grid, which helps prevent blackouts.
- Reducing GHG emissions by avoiding the use of GHG intensive peakers and fossil fuels generation.

Evolution of Demand Response Programs

When the CPUC established the first generation of DR programs in the 1980s, the DR programs included large commercial and industrial customers that could shed significant amounts of load in response to grid emergencies. Early demand response was limited to primarily interruptible programs that the IOUs could enact during system emergencies. With the advent of new technology, AMI infrastructure deployment, adoption of "smart" devices, such as smart thermostats and appliances, and increased adoption of behind-the-meter distributed energy resources (including batteries and electric vehicles), Demand Response is now able to provide load increases, decreases and load shift in response to price or reliability signals. In addition, smart or time-of-use meters allow greater monitoring of individual energy usage. All of these advances have created greater opportunities to incorporate DR as both an economic resource on par with generation and an emergency resource to help maintain the integrity of the grid during stressed days.

D.14-03-026 established the bifurcation framework for demand response. Bifurcation identified two categories of DR programs:

- **Supply-side DR (SSDR)** are event-based programs integrated into the CAISO electricity markets. These programs could be managed by Utilities or 3rd party DR aggregators. In addition to ratepayer funded DR programs, all LSEs including IOUs and CCAs can procure Supply-side DR resources through bilateral Resource Adequacy contracts. SSDR resources are counted towards LSE's RA obligations.
- **Load-Modifying DR (LMDR)** programs operate outside the CAISO market. The types of programs that would fall under this includes Time-Of-Use rates, where high prices during peak hours encourage customers to shift their load to lower priced periods. Time of Use rates, with daily peak and off-peak periods, are reflected in the CEC's load forecast, and in this way reduce the resource adequacy requirements for load serving entities.

2024-2027 Demand Response Budget Applications

In D.23-12-005, the CPUC approved the IOUs' Demand Response programs and budgets for program years 2024 through 2027. The CPUC authorized $1.55 billion in total DR funding for the three IOUs. SCE was authorized $812.02 million, PG&E was authorized $616.01 million, and SDG&E was authorized $120.65 million.

During the latest DR application proceeding, the CPUC made substantial improvements to the DR program to enhance program performance and cost effectiveness.

The Commission also did not approve any proposed DR programs that were not deemed cost effective. Aside from pilots, any proposed program with a TRC below 1.0. was denied.

Future Demand Response

The Commission continues to enhance the reliability, accountability, performance and cost effectiveness of DR resources. The Commission also continues to explore new technologies and DR programs designs through administering pilots including pilots to test for DR exports and adoption of hourly marginal cost dynamic rates. Rulemaking (R.)22-07-005 supports the California Energy Commission Load Management Standards, which call for customers to have access to dynamic rates, updated at least hourly to reflect grid conditions, by 2027. The Load Management Standards require California's large electric utilities and CCAs to provide residential and commercial customers access to time-dependent rates and programs designed to better align demand with available renewable resources.

The CPUC in this rulemaking expanded the scope of pilots in SCE and PG&E territory that are testing customer response to Load Management Standards compliant dynamic rates. D.24-01-032 expanded PG&E's agricultural pilot to more agricultural customers and end uses, as well as to commercial, industrial, and residential customers including customers of CCAs. The PG&E and SCE pilots were expanded through December 2027, with an enrollment target of 50 MW for each, and a minimum enrollment target of 10 MW of shiftable load. Because there were two parts to PG&E's pilot expansion, the total megawatt target, between SCE and PG&E, is 150 MW.

Customer Generation

The CPUC has taken actions that support the development of customer-sited distributed energy resources and related technologies by providing financial incentives. The DG programs that provide financial incentives to participating customers include the Disadvantaged Communities – Single-family Solar Homes (DAC-SASH) Program, the Self-Generation Incentive Program (SGIP), and the Solar on Multifamily Affordable Housing (SOMAH) program. In addition, net energy metering (NEM) and the newer net billing tariff (NBT) provide customer-generators with bill credits for power generated by their onsite systems that is fed back into the grid as well as the ability to offset load behind-the-meter.

Table 5.3: 2024 GHG Auction Proceeds Funded Demand Side Management and Customer Programs ($000)[71]

	PG&E	SCE	SDG&E	Total
Disadvantaged Communities Single-Family Solar Homes, Green Tariff & Community Solar Green Tariff	$19,701	$7,172	$1,813	**$28,686**
Solar on Multifamily Affordable Housing[72]	$35,075	$49,856	$13,600	**$98,531**
Total	**$54,327**	**$53,700**	**$15,609**	**$123,636**

Disadvantaged Communities Single-Family Solar Homes (DAC-SASH), Disadvantaged Communities-Green Tariff (DAC-GT), and Community Solar Green Tariff (CSGT) Programs

AB 327 required the CPUC to develop "specific alternatives designed for growth [in adoption of renewable generation] among residential customers in disadvantaged communities." The CPUC determined that installations under the SOMAH Program (D.17-12-022) should count towards the obligation to develop alternatives for DACs but also recognized the need to develop multiple programs and tariff options to address the variety of barriers that residents of DACs face. Thus, D.18-06-027, adopted in June 2018, established three additional programs to provide households in DACs access to renewable energy: two rate programs (the DAC-Green Tariff (DAC-GT) and the Community Solar Green Tariff (CSGT) programs) and a direct-install solar program, the DAC-SASH program. For these programs, DACs are defined as communities identified by CalEnviroScreen 4.0 as among the top 25 percent most impacted communities statewide, in addition to 22 census tracts in the highest 5 percent of CalEnviroScreen's Pollution Burden that do not have an overall score in the top 25 percent. In December 2020 and October 2022, respectively, the CPUC voted to expand the DAC-SASH and DAC-GT and CSGT programs' definition of DACs to include California Indian Country.

DAC-SASH provides incentives for income-qualified, single-family homeowners who live in DACs to install solar on their roofs. Modeled after the previously existing SASH program, DAC-SASH has a budget of $10 million per year through 2030. By the end of 2024, DAC-SASH had helped install 3,013 rooftop solar systems, totaling 11.97 MW.

DAC-GT enables income-qualified, residential customers in DACs who may be unable to install solar on their roof to benefit from utility scale clean energy and receive a 20 percent bill discount. The program is modeled after the existing Green Tariff portion of the Green Tariff/Shared Renewables Programs and is

[71] Table 5.3 shows the Demand Side Management programs paid for by IOUs' GHG proceeds.

[72] SDG&E Advice Letter 4613-E-B, SCE Advice Letter 5482-E-B, PG&E Advice Letter 7521-E-B.

available to customers who meet the income eligibility requirements for the CARE and FERA programs. As of October 2024, approximately 30,000 customers have been enrolled using interim RPS resources and 96 MW of new solar projects were approved, the first of which became operational in late 2024.

CSGT enables residential customers in DACs who may be unable to install solar on their roof to benefit from a local solar project and receive a 20 percent bill discount. The communities work with a local non-profit or government "sponsor" to organize community interest and present siting locations to the utility or CCA; the sponsor can also receive an incentive for its efforts. D.24-05-065 transferred most CSGT capacity to the DAC-GT program except for 3.37 MW administered by Clean Power Alliance. Customer enrollment is expected to begin in 2025 once the projects become operational. In May 2024, as part of the Community Solar Proceeding (A.22-05-022), the CPUC expanded and improved its existing community solar programs (DAC-GT and Green Tariff) and launched a new Community Renewable Energy (CRE) Program. Implementation details of the Green Tariff and CRE Program are currently under review.

Solar on Multifamily Affordable Housing (SOMAH) Program

AB 693 directed the CPUC to develop a program that provides financial incentives for the installation of solar energy photovoltaic (PV) systems on multifamily affordable housing properties throughout California. The CPUC issued D.17-12-022, which outlined the program design for the new SOMAH program in the service territories of PG&E, SCE, SDG&E, Liberty Utilities, and PacifiCorp. SB 355 (Eggman, 2023) expanded the program's eligibility pathways to include qualified tribal-owned housing, mobile home parks, public housing authority housing, public agency housing, and new construction builds going beyond code requirements for renewable energy starting January 1, 2024. In addition to building on many of the program successes and lessons learned from the CSI-funded MASH Program, the SOMAH program seeks to:

- Direct up to $100 million annually from the electric IOUs' Greenhouse Gas Auction allowance value towards subsidized solar energy systems on multifamily affordable housing.[73]
- Encourage the development and installation of solar energy systems in California's disadvantaged and low-income communities and properties owned by California Native Tribes.
- Develop, by December 31, 2032, at least 300 MW of installed solar generating capacity.

The SOMAH Program opened on July 1, 2019, and continues to develop and implement strategies to ensure a robust pipeline of applications. In July 2023, SOMAH program evaluation showed that energy production and monthly electrical bill savings were realized – ranging from a 40 to 60 percent average monthly discount.[74] The evaluator also determined that SOMAH will remain on track to reach its installation goal if new strategies for outreach and reducing participation barriers are realized. The CPUC adopted new policies to refine and improve the SOMAH program in D.24-11-006. SOMAH will now

[73] D.20-04-012 authorized funding collection through June 2026.

[74] Verdant Associates, "Solar on Multifamily Affordable Housing Second Triennial Report" (July 2023) CALMAC ID CPU0360.01. Retrievable at: SOMAH_Second_Triennial_Report_(1).pdf (calmac.org)

provide incentives for solar with integrated storage to advance resiliency and optimize monthly electrical bill savings. SOMAH will also issue early incentive payments for tribal projects to ameliorate financing barriers.

As of January 2025, the program has 436 active applications, with 35 percent of these in disadvantaged communities with $134 million in reserved incentives. There are 269 completed projects with 28 percent in disadvantaged communities, and these projects in total received approximately $72 million in incentives. For completed projects, the average system size was 168 kW, and they were given an average incentive of $386,500. Active applications and completed projects together equaled 98.9MW, or 33 percent of the way to the program's 300 MW goal.

Self-Generation Incentive Program (SGIP)

Established in 2001, SGIP provides incentives to support distributed energy resources that will result in reductions in GHG emissions and peak demand. SGIP is one of the longest-running DG incentive programs in the country. Ratepayer SGIP is set to sunset at the end of 2025. Since the program's inception, over $2.1 billion in SGIP incentives have been paid out to over 53,000 projects comprising almost 1.6 GW of capacity. In 2024, almost $128 million was paid out to 6,000 projects compromising 114 MW of capacity; all but $13 million went to energy storage systems. At the end of 2024, $383 million was reserved by 6,900 projects compromising 388 MW of capacity.

- CPUC D.24-03-071 allocated $280 million in legislatively appropriated state General Fund monies from AB 209 (Ting, 2023) for eligible low-income residential customers who install either new behind-the-meter solar PV systems paired with energy storage or new standalone energy storage systems to the existing SGIP program administrators and LADWP. These funds will become available to applicants in 2025 with a new Advanced Payment Program that allows applicants to receive 50 percent of the SGIP incentive upfront to better cover project costs and reduce barriers to low-income residential participation.
- CPUC D.24-03-071 added additional program requirements to increase grid benefits of SGIP systems such as requiring participation in an approved Demand Response program and requiring applicants to transition to the Net-Billing Tariff.
- The ratepayer program was reauthorized by SB 700 (Wiener, 2018) to allow ratepayer collections of $830 million between 2020-2024 and program administration through 2025. The ratepayer program funds are collected from PG&E, SCE, SDG&E, and SoCalGas. In 2025, the CPUC will determine rules for how to sunset the long-standing ratepayer SGIP and set an end date for the General Funds SGIP budget.

Additional Background on SGIP

- CPUC D.20-01-021 allocated the $830 million authorized in ratepayer collections across the SGIP budget categories: 88 percent to energy storage and 12 percent to renewable generation. Within energy storage, an additional $512 million was allocated to the Equity Resiliency Budget (ERB) created in D.19-09-027. The ERB provides incentives to support resiliency for households and facilities in areas of high wildfire risk where power safety shut-off events are more frequent.

- Qualifying technologies include wind turbines, waste heat to power technologies, pressure reduction turbines, internal combustion engines, microturbines, gas turbines, fuel cells, linear generators, and advanced energy storage systems. For non-residential systems, half of the incentive is paid up-front, and half of the incentive is paid based on the performance of the technology over five years.

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

California's NEM tariffs and NBT 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. Unlike the other programs in this section, the costs associated with NEM and the NBT come from the cost shift (from participating customers to non-participating customers) rather than from program funds. Because retail rates include recovery of system costs that are not avoided by distributed generation, bill credits for customer-generators cause a revenue shortfall that is recovered through increased rates for customers not participating in NEM or the NBT (who on average have lower incomes than NEM and NBT customers).[75]

The NEM 1.0 and NEM 2.0 cause a cost shift in two ways: (1) ratepayers 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) ratepayers pay for the part of bill savings experienced by NEM customers because the program allows them to bypass their share of direct costs to maintain the electric grid, which ratepayers without NEM systems end up paying. NEM 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.

Pursuant to AB 327, in January 2016, the CPUC approved D.16-01-044 adopting a NEM successor tariff (NEM 2.0) for customers starting NEM service after each utility reached its statutory five percent NEM capacity cap. Customers on NEM 2.0 pay an interconnection fee and small non-bypassable charges.[76] They also take service on a time-of-use rate plan. In 2016, the CPUC stated its intention to later revisit the NEM successor tariff.

In 2019, the CPUC commissioned an independent evaluation of NEM 2.0.[77] The evaluation found that the tariff is not cost-effective from a combined participant/utility perspective or for non-participating ratepayers. The study also found that after NEM 2.0 system installation, the average residential customer-

[75] The evaluation of NEM 2.0 is available at cpuc.ca.gov/nem2evaluation.

[76] For purposes of the NEM successor tariff, the relevant non-bypassable charges are: Public Purpose Program Charge; Nuclear Decommissioning Charge; Competition Transition Charge; and Department of Water Resources bond charges.

[77] The draft and final reports are available at cpuc.ca.gov/nem2evaluation.

generator pays much less than the estimated cost to serve them, while the average non-residential customer-generator pays more.[78] In August 2020, the CPUC opened R.20-08-020 to revisit the NEM successor tariff.

In December 2022, the CPUC adopted D.22-12-056, which established the framework for the NBT. NEM 2.0 was closed to new applications on April 15, 2023. Like NEM 2.0, the new tariff provides cost savings to new solar customers, while reducing (but not eliminating) the cost shift paid by non-solar customers compared to if NEM 2.0 had remained open, thus improving the equity of the tariff and helping to facilitate the state's building electrification goals.

Record numbers of NEM 2.0 applications were received during the period from late 2021 to 2023 when the CPUC publicly considered and then set a date for closing enrollment in NEM 2.0. Due to continued NEM 2.0 installations and NBT installations, the third highest annual amount of NEM and NBT capacity was added in 2024, after 2023 and 2022. There were over 283,000 installations in 2023, and over 166,000 in 2024. For comparison, the 2016-2020 average installation rate was 129,000 per year.

The NBT reduces the cost shift compared to NEM 2.0 by decoupling import rates and export rates and by mandating more cost-based price signals for customers. NBT customers take service on high-differential time-of-use rates that discourage imports during the evening when grid electricity is the most expensive and emits the most GHGs. The tariff also has hourly export price signals that encourage exports when the grid needs it most – for example, during late summer evenings. Together, these two components create a dynamic where most customers fare better financially by purchasing solar paired with battery energy storage than by purchasing only solar. These tariff changes drove increasing rates of solar installations paired with storage compared to NEM 2.0, e.g., in 2024 NBT battery installations equaled 69 percent of NBT solar installations, while NEM battery installations equaled 22 percent of NEM solar installations.[79]

In November 2023, the CPUC adopted D.23-11-068, which made similar reforms as in the previous Decision, but for multi-tenant and multi-meter properties, by establishing a virtual net billing tariff (VNBT) and an aggregation subtariff of the NBT. It also enhanced solar consumer protections, specified plans for a future evaluation of proceeding outcomes, clarified NEM Fuel Cell tariff requirements, and provided for implementation of the prevailing wage mandate in PU Code Section 769.2. The NEM 2.0 versions of these tariffs closed to new applications on February 14, 2024.

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[78] The study also provided analysis, not summarized here, regarding customers' energy usage before and after installing renewable energy generation systems on the NEM 2.0 tariff, effects on cost-effectiveness of the addition of energy storage or the removal of the federal investment tax credit, cost-effectiveness compared to NEM 1.0, characteristics of the NEM 2.0 participant and non-participant populations, and other topics.

[79] Data from californiadgstats.ca.gov, current as of March 30, 2025. The percentages reported include both new paired solar and storage systems and a relatively small number of batteries that were added to existing solar systems. Note that NEM battery installation has increased since the adoption of D.22-12-056. In 2022, NEM battery installations equaled only 13 percent of NEM solar installations.

Income-Qualified Programs

Per California state statute, the CPUC oversees the three large electric IOUs' implementation of the California Alternate Rates for Energy (CARE) and Family Electric Rate Assistance (FERA) bill discount programs, and the energy efficiency Energy Savings Assistance (ESA) program for income-qualified households.

California Alternate Rates for Energy (CARE)

The CARE program is an energy rate assistance program that provides a discount on energy bills to income-qualified households. The CARE program provided $2.3 billion in ratepayer funded bill assistance that was paid for by non-exempt non-CARE customers as part of a statutory "public purpose program surcharge" that appears on utility bills. The income qualifications for the CARE program are households that are at or below 200 percent of the Federal Poverty Guidelines. In 2024, the program provided discounts to approximately 4.1 million income-qualified electric customers, which represents roughly 30 percent of electric residential customers in California.

The CARE program was established in 1989 by PU Code Sections 739.1 and 739.2, which authorizes a 15 percent rate discount for income-qualified customers off their energy bills.

In October 2013, AB 327 required the IOUs to restructure the CARE discount rates and to set an effective electric rate discount between 30-35 percent. In compliance with AB 327 and D.15-07-001, the effective discounts were reduced to 35 percent for PG&E and SDG&E and remained at 32.5 percent for SCE. These reductions occurred gradually to prevent rate shock. The CARE program also provides a 20 percent discount on customers' natural gas bills.

On May 9, 2024, the CPUC approved D.24-05-028 which implemented the provisions of AB 205 (Committee, 2022). AB 205 amended PU Code Section 739.1(c)(1) to require the CPUC to adjust the calculation of the average effective CARE discount to "not reflect" any of the charges for which CARE customers are exempted. In effect, this increases the discount that CARE customers receive by maintaining the prior discount percentages that were adopted in D.15-07-001 but requiring those discounts to be incremental to any rate exemptions that CARE customers receive. D.24-05-028 required the utilities to implement the updated definition of the CARE average effective discount on January 1, 2025. Therefore, over the past several years, SB 695, AB 327 and AB 205 have led to increases in the effective CARE discount, which is now nearing approximately 40 percent.

In 2024, CARE provided an estimated $2.4 billion in annual subsidies and served 4.8 million income-qualified customers statewide, more than 1 million of which were new customer accounts added last year.[80] CARE provides a nearly 40 percent bill discount to nearly 30 percent of California electric customers. A

[80] Some customers are enrolled in more than one program, for example SCE for electricity and SoCalGas for natural gas.

Source: 2024 Investor-Owned Utility ESA-CARE-FERA Monthly Reports, posted to Docket A.19-11-003.

higher CARE subsidy does not result in a higher revenue requirement for the utility, but it does increase the rates that non-CARE customers pay. Even for non-CARE customers though, the CARE program surcharge has long been a small percentage of their energy bill. For example, in 2023, the average CARE surcharge on a non-CARE residential monthly electric bill was 4.1 percent of the total bill, which translates to around $4.84 a month on average. Similarly for residential gas bills, the average CARE surcharge on a non-CARE residential monthly gas bill was about 2.07 percent of the total bill, which equals around $1.62 a month.[81]

PG&E's CARE subsidy in 2024 was approximately $1.1 billion (electric and gas combined), compared to $855 million for SCE, $212 million for SDG&E (electric and gas combined), and $180 million for SoCalGas (see **Table 5.4**).

Table 5.4 2024 CARE Program Costs ($000)[82,83]

Utility	Operations	Subsidy	Administrative Costs	Total
PG&E	Electric	$937,864	$6,478	**$944,342**
	Gas	$165,415	$1,619	**$167,035**
SCE	Electric	$855,579	$7,796	**$863,375**
SDG&E	Electric	$192,310	$5,304	**$197,614**
	Gas	$20,132	$534	**$20,666**
SoCalGas	Gas	$180,437	$9,064	**$189,502**
Total		**$2,351,737**	**$30,795**	**$2,382,532**

Energy Savings Assistance Program (ESA)[84]

The ESA program is a no-cost to participant direct-install energy efficiency program that provides home weatherization services and energy efficiency measures to help low-income households conserve energy, reduce their energy costs/utility bills, and improve the health, comfort, and safety of the home. The program also provides information and education to promote energy efficient practices in low-income

[81] Source: 2023 Investor-Owned Utility ESA-CARE Annual Reports, posted to Docket A.19-11-003.

[82] Source: 2024 Investor-Owned Utility ESA-CARE Monthly Reports, posted to Docket A.19-11-003. Final program costs will be available in IOU Annual Reports for Program Year 2024 on May 1, 2025.

[83] CARE administration costs shown in Table 5.4 reflect the IOUs' current reported expenditures. These amounts may not necessarily match the collection amounts shown in Table 5.1.

[84] Formerly known as the Low-Income Energy Efficiency (LIEE) Program.

communities. ESA is funded by all utility customers as part of a statutory “public purpose program surcharge” that appears on utility bills.

Effective July 2022, as a result of SB 756 (Hueso, 2021), which addressed home weatherization services for low-income customers, ESA expanded to a greater number of California low-income households at or below 250 percent of the Federal Poverty Guidelines. For calendar year 2024, a family of four making $78,000 or less was eligible for ESA.

ESA’s original program objective was to promote equity and relieve low-income customers of the burden of rising energy prices. The program has evolved into a resource program that achieves energy savings while improving quality of life for low-income customers.

The CPUC initiated the first energy efficiency programs for low-income customers in the early 1980s. In 1990, the California legislature adopted and codified the ESA program in PU Code Section 2790 requiring electrical and gas corporations to perform home weatherization services for low-income customers in their service territory, taking into consideration both the cost-effectiveness of the services and the policy of reducing hardships for low-income households.

In 2007, the CPUC adopted a programmatic initiative in D.07-12-051 to provide all eligible customers the opportunity to participate in the ESA program and to offer participants with cost-effective energy efficiency measures in their residences by 2020, which was subsequently codified (PU Code Section 382(e))ensuring that, by the end of 2020, all eligible and willing low-income customers would have the opportunity to participate in the ESA program. The IOUs met this goal.

In June 2021, the CPUC issued D.21-06-015 establishing ESA budgets and program designs for program years 2021 to 2026. The Decision moved away from setting ESA program goals based on the number of households treated and towards deeper energy savings goals. In early 2022, IOUs began identifying highly vulnerable ESA customers in multiple need states (for example, customers who are both income-qualified and living in Disadvantaged Communities or also enrolled in Medical Baseline). The IOUs also began ongoing monthly reporting on activity for these customer segments, including number of eligible customers, contacts made, enrollments, and household energy savings.

In 2023, the IOUs concluded their competitive ESA solicitations process and began launching the new iteration of the program towards deeper energy savings, and new program components for the multi-family sector, and electrification pilots, which is discussed in more detail below.

Most customers will receive services through the ESA Main program, where the typical measure package consists of simple lighting and water heating measures, as well as additional measures based on an on-site contractor inspection. Historically, these customers have received upgrades at a cost of about $1,000 per home, resulting in less than 5 percent annual energy savings per household.

Table 5.5 below shows the ESA Main program expenses by IOU for program year 2024 compared to 2023. The increase in spending is due to the IOUs and their contractors continuing to optimize program operations, further refine the targeting and delivery of treatments to customers, and meet the goals set in the Decision.

Table 5.5: 2024 ESA Main Program Expenses ($000)[85]

Utility	Operations	ESA Main Expenses 2024	ESA Main Expenses 2023	Percent Increase from 2023 to 2024
PG&E	Electric and Gas	$112,661	$119,882	(6%)
SCE	Electric	$59,521	$23,354	155%
SDG&E	Electric and Gas	$15,877	$14,061	13%
SoCalGas	Gas	$76,709	$67,177	14%
Total		**$264,768**	**$224,473**	**18%**

In 2024, the ESA Main program served nearly 150,000 households, and achieved about 50 GWh and 2.7 MMtherms of annual energy savings.[86] This was about a 10 to 30 percent increase from program year 2023. About 85 percent of the total ESA expenses goes towards the ESA Main program; this percentage may decline over time as the Multi-Family Energy Savings (MFES) program and pilot programs ramp up and these program budgets are expended.

In 2023, per Decision directive, the IOUs launched a new multi-family component within the ESA program – the MFES program - addressing in-unit tenant areas, common areas, and whole building / property areas, providing energy efficiency measures for deed and non-deed restricted properties. This program expands upon the previous multi-family common area measures program, and provides tenants and property owners throughout the state the opportunity to receive energy efficiency upgrades through either the Northern MFES program, led by PG&E, or the Southern MFES program, led by SDG&E. Also in 2023, the ESA programs launched deeper energy savings and building electrification pilot programs. The deeper energy savings pilots are being launched individually by PG&E and SDG&E, with a joint program by SCE and SCG. The objective of the deeper energy savings pilot program is to move beyond the previous ESA savings levels of less than 5 percent per household to up to 50 percent energy savings per household. The target household of this program is a single-family household in a more extreme climate zone that has high usage and bills. This typical household will be able to benefit from a more comprehensive package of upgrades than what the ESA Main program typically provides to a household, about $1,000 investment per home, towards investment levels that often exceed $5,000 per home. The typical measure package may include insulation, new appliances, and new heating and cooling systems. The building electrification pilots have also launched and are being implemented by SCE in their own territory and include a program to retrofit existing homes with electric heat pumps and heat pump water heaters, and other electrification end use measures. SCE is also running a new construction electrification pilot to provide technical design assistance, incentives, and tenant education to housing developers for all-electric construction. **Table 5.6** shows the ESA MFES and pilot programs expenses by IOU for program year 2024 compared to 2023, and

[85] Source: 2024 Investor-Owned Utility ESA-CARE Monthly Reports, posted to Docket A.19-11-003.

[86] Final household treatment numbers will be available in IOU Annual Reports for Program Year 2024 on May 1, 2025.

the increase in expenses since last year. The increase in spending is driven by the IOUs effort to ramp up delivery of these new programs, identify the niche customer type that is eligible and can benefit from a more customized treatment, and deliver energy savings.

Table 5.6: 2024 ESA MFES and Pilots Program Costs ($000)[87]

Utility	Operations	ESA MFES and Pilots Expenses 2024	ESA MFES and Pilots Expenses 2023	% Increase from 2023 to 2024
PG&E	Electric and Gas	$31,997	$12,622	154%
SCE	Electric	$6,433	$4,776	35%
SDG&E	Electric and Gas	$4,798	$2,946	63%
SoCalGas	Gas	$4,932	$5,036	(2%)
Total		**$48,160**	**$25,381**	**90%**

Customers enroll in the ESA program through various channels including leads from CARE and FERA program participants, door-to-door neighborhood canvasing, direct mail, email, community-based organizations, categorical enrollment, online, and community events. Marketing materials are available in multiple languages. ESA is an income-verified program; however, customers can be enrolled automatically if already participating in another financial assistance program with similar criteria.[88]

Family Electric Rate Assistance (FERA)

The FERA program is a low-income electric rate assistance program that provides an 18 percent discount on electric bills to income-qualified households with three or more individuals.[89] FERA is funded by a statutory "public purpose program surcharge" that appears on utility bills. The FERA program was designed to assist families that are ineligible for the California Alternate Rates for Energy (CARE) rate because their income levels are slightly above the CARE program limits.

[87] Source: 2024 Investor-Owned Utility ESA-CARE Monthly Reports, posted to Docket A.19-11-003.

[88] These are known as Categorically Eligible programs. The current list of programs include: Bureau of Indian Affairs General Assistance, CalFresh Benefits (federally known as the Supplemental Nutrition Assistance Program or SNAP and formerly known as Food Stamps), Healthy Families Category A & B, Head Start Income Eligible (Tribal Only), Low Income Home Energy Assistance Program (LIHEAP), Medicaid/MediCal, National School Lunch Program (NSL), Supplemental Security Income (SSI), Temporary Assistance for Needy Families (TANF), Women, Infant, and Children Program (WIC)

[89] Households with one and two individuals will be eligible to apply to the FERA program effective June 1, 2025. In 2024, SB 1130 (Bradford, Chapter 457, Statutes of 2024) amended Public Utilities Code section 739.12 and removed the household size requirement.

The income limits of the FERA program range from 200 percent plus $1 to 250 percent of the Federal Poverty Guidelines. PU Code Section 739.1(f)(2) requires a single application form for CARE and FERA to enable applicants to apply for the appropriate assistance program based on their level of income and family size. In 2024, SB 1130 (Bradford, 2024) amended PU Code Section 739.12 to allow utilities to provide a FERA-only application form, separate from the combined CARE and FERA program application.

The FERA program was established in 2004 by CPUC D.04-02-057 as the Lower Middle Income Large Household program. In D.05-10-044, the lower income limits of the FERA program were raised to 200 percent plus $1 of the Federal Poverty Guideline levels, which correspond to the upper limits of the CARE program. In compliance with Senate Bill 1135 (Bradford, 2018) and PU Code section 739.12, the FERA program discount increased from 12 percent to 18 percent effective January 1, 2019.

D.21-06-015 established a 50 percent enrollment goal by 2023 and a 70 percent enrollment goal by 2026. The Decision also approved FERA dedicated program management budgets and directed the utilities to create tailored marketing and outreach efforts to reach these program enrollment goals. The increase in income eligibility for the ESA program as of July 2022 allows for some cross-program marketing and enrollment between ESA and FERA. In 2024, SB 1130 amended PU Code section 739.12, expanding FERA program eligibility by removing the household size requirement of three or more individuals. Households with one and two individuals will be eligible to apply to the FERA program starting June 1, 2025, and is expected to roughly double the eligible population.

PG&E's FERA subsidy in 2024 was approximately $21.3 million, compared to $15.0 million for SCE, and $3.8 million for SDG&E. At the end of 2024, approximately 84,520 households were enrolled in FERA out of an estimated 409,670 eligible households.[90] IOUs have not yet met the 50 percent enrollment goal by 2023 and are exploring ways to increase program enrollment and meet the 2026 enrollment goal. **Table 5.7** shows the 2024 FERA program costs.

Table 5.7: 2024 FERA Program Costs ($000)[91]

Utility	Operations	Subsidy	Administrative Costs	Total
PG&E	Electric	$21,280	$2,009	**$23,289**
SCE	Electric	$14,963	$593	**$15,556**
SDG&E	Electric	$3,828	$643	**$4,471**
Total		**$40,071**	**$3,245**	**$43,316**

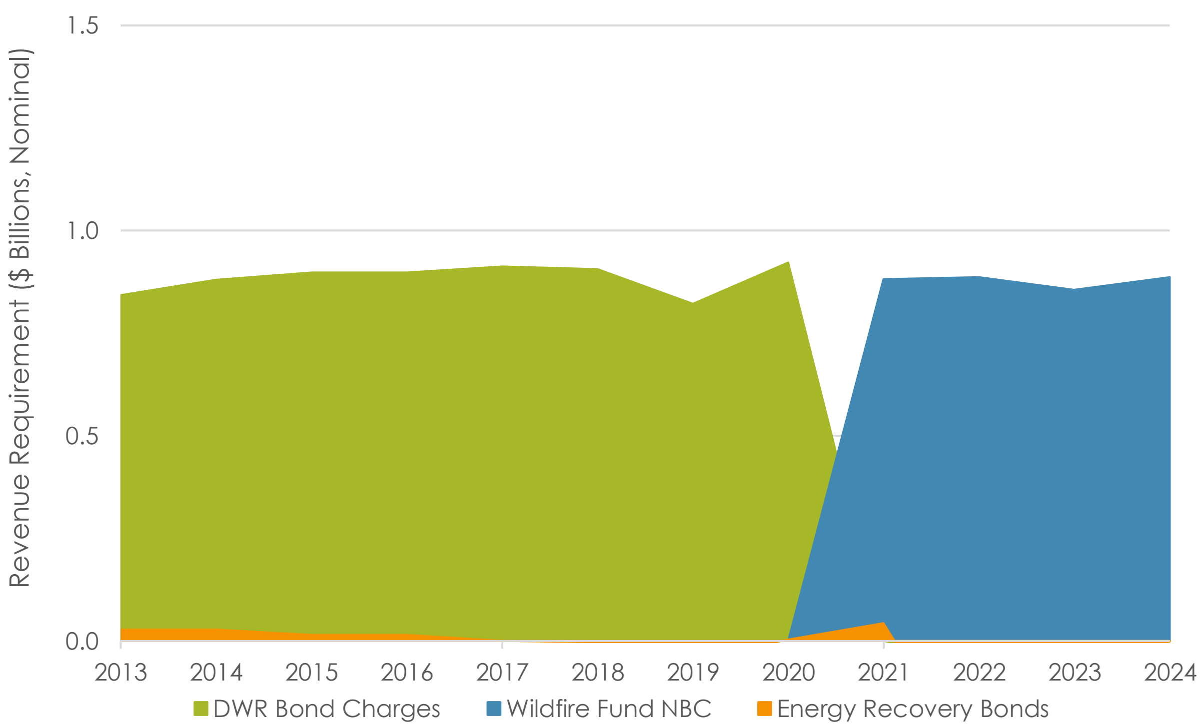
[90] Source: 2024 Investor-Owned Utility FERA Annual Reports, posted to Docket A.19-11-003.

[91] Source: 2024 Investor-Owned Utility FERA Annual Reports, posted to Docket A.19-11-003.

VI. Bonds, Regulatory Fees, and Legislative Program Costs

During the era of electric restructuring, the State and the utilities issued a series of bonds to amortize the costs of energy restructuring and the energy crisis of 2000-2001. Since the energy crisis, these bond costs have decreased from a peak of approximately $2 billion in 2005 to approximately $900 million through September 2020 and then were retired in 2021. As discussed in further detail below, beginning in October 2020, the bond charges were replaced by the Wildfire Fund Non-Bypassable Charge revenue requirement of $902.4 million, as illustrated in **Figure 6.1**.

Figure 6.1: Trends in Bond and Wildfire Fund Expenses ($ Billions)



DWR bonds were issued in 2003 to recover the excess costs incurred by the State of California to purchase power during the energy crisis. As of September 30, 2020, enough funds were collected from ratepayers to retire the DWR bonds, and consequently the DWR bond charge expired.

As part of the CPUC and PG&E bankruptcy settlement agreement reached after PG&E's first bankruptcy in 2001, the utility was authorized to recover $2.2 billion as a Regulatory Asset. This was a separate and additional part of PG&E's rate base. Energy Recovery Bonds were issued by PG&E in 2003 to reduce the financing cost of the Regulatory Asset to ratepayers. Charges associated with the Energy Recovery Bonds ceased in 2012.

On October 1, 2020, pursuant to AB 1054 and CPUC D.19-10-056, the Wildfire Fund Non-Bypassable Charge (NBC) was implemented with an annual revenue requirement of $902.4 million combined for the large electrical utilities. The 2020 Wildfire Fund NBC was equivalent to the expired DWR bond charge, and was identical in 2021, resulting in no 2021 bill increase to customers. Since 2021, there have been slight increases and decreases to the Wildfire Fund NBC to adjust for annual over/under collections. Pursuant to AB 1054, the Wildfire Fund NBC revenue requirement will remain in effect until January 1, 2036.

In addition, AB 1054 authorizes the CPUC to issue a financing order allowing IOUs to issue recovery bonds to finance the first $5 billion of approved wildfire mitigation capital expenditures in aggregate among the three large electric IOUs (PU Code Section 8386.3(e)). This program saves ratepayers money by allowing lower cost financing compared to traditional utility financing mechanisms. The CPUC has thus far issued six financing orders under PU Code Section 8386.3(e).

D.20-11-007 granted SCE's request to implement a fixed recovery charge and issue recovery bonds to finance $327 million of Grid Safety and Resiliency Program (GSRP) capital expenditures and D.21-10-025 granted SCE's request to implement a fixed recovery charge and issue recovery bonds to finance $526 million of GRC Tracks 1 & 2 Wildfire Mitigation capital expenditures. D.23-02-023 granted SCE's request to implement a fixed recovery charge and issue recovery bonds to finance $730.4 million of approved Wildfire Mitigation capital expenditures. The resulting AB 1054 bond charges for SCE in 2024 appear in **Table 6.1** under the category Wildfire Securitization.

Similarly, pursuant to AB 1054, PG&E filed Application (A.) 21-02-020 requesting authority to implement a fixed recovery charge and issue recovery bonds to finance up to $1.2 billion of approved wildfire mitigation capital expenditures. D.21-06-030 approved PG&E's request which ultimately resulted in a securitization bond issuance totaling $860 million. D.22-08-004 authorized PG&E to implement a fixed recovery charge and issue up to $1.4 billion of recovery bonds, which resulted in financing of $975 million of approved Wildfire Mitigation capital expenditures. D.24-02-011 authorized PG&E to implement a fixed recovery charge and issue up to $1.412 billion of recovery bonds, which resulted in financing of $1.385 billion of approved Wildfire Mitigation capital expenditures. The resulting AB 1054 bond charges for PG&E in 2024 appear in **Table 6.1** under the category Wildfire Securitization.

Table 6.1 shows the Bond Expenses and Wildfire Securitization components of the 2024 revenue requirement for each of the large electric IOUs.

Table 6.1: 2024 Bond Expenses ($000)

	PG&E	SCE	SDG&E	Total
DWR Bond Charges	0	0	0	**0**
Rate Reduction Bonds	0	0	0	**0**
Energy Recovery Bonds	(2,006)	0	0	**(2,006)**
Wildfire Fund NBC	393,053	408,912	84,674	**886,639**
Wildfire Securitization	282,386	106,244	0	**388,630**
Total	**673,433**	**515,156**	**84,674**	**1,273,263**

Fees

Fees include charges levied by state and local governments. For example, the CPUC Reimbursement Fee reimburses the State for the cost of regulating the utilities. **Table 6.2** shows the 2024 revenue requirement for the CPUC Reimbursement Fee.

Table 6.2: 2024 Regulatory Fees ($000)

Fee	PG&E	SCE	SDG&E	Total
CPUC Reimbursement Fee*	79,241	80,195	0	**159,436**

*SDG&E does not include the CPUC fee in the revenue requirements. SDG&E CPUC fees are a surcharge applied to customer bills and therefore are not included in the rates. The 2024 electric CPUC reimbursement fees for PG&E, SCE, and SDG&E were $0.0010/kWh.

- **CPUC Reimbursement Fee:** This is the annual fee to be paid by utilities to fund their regulation by the CPUC (California Public Utilities (PU) Code Section 401-443). The surcharge to recover the cost of that fee is ordered by the CPUC under authority granted by PU Code Section 433.

Legislative Program Costs

Various electric programs, operated by the IOUs, are mandated by the State of California. Most programs aim to provide California with clean energy, while some programs provide subsidies to various customer groups. Some bonds and regulatory fees may also be mandated by the State. **Table 6.3** shows the 2024 electric revenue requirement for the legislative mandates.

Table 6.3: 2024 California Mandated Programs Revenue Requirement ($000)

Program Name	Legislation/ PU Code	PG&E	SCE	SDG&E	Total
Aliso Canyon Energy Storage	AB 2514 (Skinner, 2010)	0	8,944	0	**8,944**
Bioenergy Market Adjusting Tariff Non-Bypassable Charge	SB 1122 (Rubio, 2012)	6,994	(7,360)	0	**(366)**
California Energy Systems for 21st Century	SB 96 (Committee, 2013)	0	0	0	**0**
California Hub for Energy Efficiency Financing (CHEEF)	PU Code § 454.5(b)(9)(C)	0	0	0	**0**
California Solar Initiative - Multifamily Affordable Solar Housing/Single-Family Affordable Solar Homes	SB 1 (Murray, 2006), AB 217 (Bradford, 2013), AB 2723 (Pavley, 2006)	(54,220)	0	(9,943)	**(64,163)**
CPUC Fee	PU Code 431-432	79,241	80,195	0	**159,436**
Demand Response [92]	SB 73 (Committee, 2013), SB 1414 (Kehoe, 2010), AB 793 (Quirk, 2015)	197,659	49,299	10,713	**257,671**
Department of Water Resources Bond	AB X1 (Keeley and Migden, 2001) and D. 01-03-081	0	0	0	**0**
Disadvantaged Communities - Single-Family Affordable Solar Homes, Green-Tariff, Community Solar Green Tariff	AB 327 (Perea, 2013)	19,701	7,172	1,813	**28,686**
Economic Development Rate Balancing Account (EDRBA)	PU Code § 740.4(a) and 740.4(c)	0	0	933	**933**
Electric Program Investment Charge/New Solar Homes Partnership Program	PU Code § 399.8, SB 1, SB 32, SB 350 (de León, 2015), SB 854, AB 66 (Muratsuchi, 2013), AB 523 (Reyes, 2017), AB 802 (Williams, 2015), AB 1890 (Brulte, 1996), AB 2140 (Hancock, 2006), AB 2218 (Bradford, 2014)	99,681	76,885	16,280	**192,846**

[92] Demand Response includes Demand Response Auction Mechanism and IDSM for SCE and SDG&E.

Program Name	Legislation/ PU Code	PG&E	SCE	SDG&E	Total
Electric Vehicle Programs (includes pilots)	Senate Bill 350 (De León and Leno, 2015), AB 1082, (Burke, 2017), AB 1083 (Burke, 2017) (pilots)	18,838	0	0	**18,838**
Energy Efficiency	SB 350 (De León and Leno, 2015), AB 32 (Nunez and Pavley, 2006), AB 802 (Williams, 2015), AB 1330 (Bloom 2016), AB 1890 (Brulte, 1996)	159,005	288,997	32,776	**480,778**
Energy Savings Assistance Program/California Alternate Rates for Energy Program[93,94]	PU Code § 2790, § 382, SB 580 (Escutia, 2005), SB 691, AB 327 (Perea, 2013), AB 793 (Quirk, 2015), AB 2140 (Hancock, 2006), AB 2857 (Lieber, 2008)	1,019,380	929,330	207,446	**2,156,156**
Family Electric Rate Assistance[95]	SB 987 (Hollingsworth, 2010) and SB 1135 (Bradford, 2018)	23,289	15,556	4,471	**43,316**
Green Tariff Shared Renewables	SB 43 (Wolk, 2013)	0	9,741	0	**9,741**
Greenhouse Gas Cost[96]	AB 32 (Nunez and Pavley, 2006), SB 43 (Wolk, 2013), SB 854 (Committee, 2018), AB 57 (Wright, 2002)	99,077	466,668	137,345	**703,090**
Greenhouse Gas Revenue Return	AB 32 (Nunez and Pavley, 2006), SB 43 (Wolk, 2013), AB 57 (Wright, 2002)	(689,321)	(955,105)	(247,498)	**(1,891,924)**

[93] Energy Savings Assistance Program (ESA)/California Alternate Rates for Energy (CARE) Program costs include administrative expenses. CARE costs include subsidies. ESA costs reflect amounts spent on electric-related measures and program expenses. Note that it is possible for utilities to fund electric-related measures and programs using collections from gas customers as well as electric customers.

[94] ESA and CARE costs shown here in Table 6.3 are actual expenses. ESA and CARE costs shown earlier in Table 5.1 are costs collected in rates.

[95] Family Electric Rate Assistance costs include administrative expenses.

[96] PG&E's Greenhouse Gas Cost is presented as a five-year average.

Program Name	Legislation/ PU Code	PG&E	SCE	SDG&E	Total
Hazardous Substance Memorandum Account	AB X1- 6 (Dutra, 2001)	45,960	2,875	162	**48,997**
Mobile Home Park Program	PU Code § 2791-2799	17,476	18,034	17,950	**53,460**
Net Energy Metering[97]	AB 1070 (Gonzalez Fletcher, 2017)	0	0	0	**0**
Net Energy Metering Cost Shift	AB 1070 (Gonzalez Fletcher, 2017)	3,829,999	2,197,213	1,063,404	**7,090,616**
New Home Energy Storage Pilot	AB 2514 (Skinner, 2010), AB 2868 (Gatto, 2016)	0	0	0	**0**
New Solar Homes Partnership Program	AB X1-14 (Matthews, 2001), AB X1-15 (Pacheco, 2002), SB 1 (Murray, 2006)	0	0	0	**0**
Officer Compensation	SB 901 (Dodd, 2018)	0	0	0	**0**
Percentage of Income Payment Program (PIPP)	SB 598 (Hueso, 2017)	2,857	0	700	**3,557**
Public Purpose Programs Adjustment Mechanism	Various public purpose programs identified above	0	64,574	0	**64,574**
Renewable Portfolio Standard[98]	AB 32 (Nunez and Pavley, 2006), SB 1078 (Sher, 2002), SB 350 (de León, 2015), SB 100 (de León, 2018)	1,884,270	2,449,949	506,239	**4,840,458**
Residential Uncollectible Balancing Account (RUBA)	SB 598 (Hueso, 2017)	0	0	8,100	**8,100**
San Diego Unified Port District	AB 628 (Gorell and Hall, 2013)	0	0	0	**0**
San Joaquin Valley Disadvantaged Communities Pilot and Data Gathering	AB 2672 (Perea, 2014)	0	0	0	**0**

[97] Net Energy Metering includes solar system contracts and disclosures, as applicable.

[98] RPS revenue requirements do not distinguish the above-market portion. PG&E's RPS value is presented as a five-year average.

Program Name	Legislation/ PU Code	PG&E	SCE	SDG&E	Total
School Energy Efficiency Stimulus Program	AB 841 (Ting, 2020)	0	0	2,900	**2,900**
Self-Generation Incentive Program	AB 970 (Ducheny, Battin, and Keeley, 2000), AB 1478 (Committee, 2014), AB 1637 (Low, 2016), AB 1685 (Leno, 2003), AB 2778 (Lieber, 2006), SB 412 (Kehoe, 2009) & SB 861 (Committee, 2014), SB 700 (Wiener, 2018), AB 1144 (Friedman, 2019)	59,877	56,626	22,022	**138,525**
Smart Grid	AB 32 (Nunez and Pavley, 2006), SB 17 (Padilla, 2009)	726	0	0	**726**
Smart Heat Pump Water Heater (SHPWH) Program	AB 2513 (Pellerin, 2024), AB 2868 (Gatto, 2016)	0	0	0	**0**
Solar on Multifamily Affordable Housing	AB 693 (Eggman, 2015), SB 92 (Committee, 2017)	34,626	46,528	13,796	**94,950**
Statewide Marketing Program	AB 793 (Quirk 2015), SB 350 (de León, 2015)	0	0	0	**0**
Summer Reliability OIR	July 31, 2021 Proclamation of Emergency from Governor Newsom	0	0	0	**0**
Total Rate Adjustment Component	AB 1 (Aanestad, 2001)	0	0	9,000	**9,000**
Transportation Electrification Programs[99]	SB 350 (de León, 2015), AB 1082 (Burke, 2017), AB 1083 (Burke, 2017), AB 628 (Gorell and Hall, 2013)	0	58,355	34,855	**93,210**
Tree Mortality Non-Bypassable Charge	SB 43 (Wolk, 2013), SB 859 (Committee, 2016)	20,331	16,133	(37,451)	**(987)**
Wildfire and Natural Disaster Resiliency Rebuild (WNDRR)	SB 1477 (Stern, 2018)	2,820	0	0	**2,820**

[99] Transportation Electrification includes pilots, as applicable.

Program Name	Legislation/ PU Code	PG&E	SCE	SDG&E	Total
Wildfire Fund Non-Bypassable Charge	AB 1054 (Holden, Burke, and Mayes, 2019)	393,053	408,912	84,674	**886,639**
Wildfire Hardening Fixed Recovery Charge	AB 1054 (Holden, Burke, and Mayes, 2019)	282,386	106,244	0	**388,630**
Total		7,553,705	6,395,765	1,880,687	**15,830,157**

VII. Natural Gas Utility Ratepayer Costs

The CPUC determines the reasonableness of natural gas utility operational costs, gas cost allocation among customer classes, and gas rate design for PG&E, SDG&E, and SoCalGas.

Natural gas utility costs may be categorized into the following three main components:

1) core procurement costs, 2) costs of operating the natural gas transportation system and providing customer services, and 3) costs associated with gas public purpose programs (PPP).

Unlike its process for electric utilities, the CPUC does not set an annual authorized revenue requirement for natural gas utilities' procurement costs. Utilities procure gas supplies for core gas customers (primarily residential and small commercial) only.

Utilities' gas procurement is subject to incentive mechanisms under which utilities' shareholders receive a reward if they procure gas at costs below specified benchmarks and incur a penalty if they procure gas at costs above the benchmarks. The mechanisms provide utilities with a financial incentive to manage core customers' natural gas commodity costs in a way that saves ratepayers money compared to the established benchmark. Procurement costs shown in this report pertain to these core customers.

Large volume noncore customers, such as industrial or electric generation customers, procure their own gas supplies. Therefore, this report does not discuss their procurement costs. Core gas procurement costs are recovered in utility gas procurement rates, which are adjusted monthly. The commodity gas price is the procurement cost component with the greatest variability. Monthly changes in gas commodity prices on customer bills provide consumers with some price signals so that they can adjust their gas usage when prices are high. However, since the price changes monthly, there is some delay before customers see the higher commodity prices on their bills. PG&E and SoCalGas publish the anticipated monthly commodity prices on their websites offering customers the opportunity to react to price fluctuations.[100] SoCalGas recently introduced an opt-in texting system to inform customers when there is an anticipated increase of 20 percent or more to monthly commodity prices.[101] In addition, both PG&E and SoCalGas offer texting systems to inform customers if their bills are trending higher than a specified amount, allowing customers to adjust their gas usage to avoid higher bills.[102] **Table 7.1** and **Table 7.2** below show costs for 2024 and a comparison of 2024 to prior years.

Table 7.1 shows the 2024 natural gas revenue requirement by components.

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[100] PG&E: https://www.pge.com/tariffs/en/rate-information/gas-rates.html

SoCalGas: https://www.socalgas.com/business/energy-market-services/gas-prices

[101] SoCalGas: https://www.socalgas.com/notifyme

[102] PG&E: https://www.pge.com/en/account/manage-my-account/online-account-preferences/bill-forecast-alert.html#accordion-3bfea34345-item-24c0a5a39c

SoCalGas: https://www.socalgas.com/bill-tracker-alerts

Table 7.1: 2024 Gas Revenue Requirement by Key Components ($000)

	PG&E	SoCalGas	SDG&E	Total
Core Procurement	1,018,046	1,186,439	169,879	**2,374,364**
Transportation	5,144,821	5,005,788	744,064	**10,894,673**
Public Purpose Programs	399,536	561,574	60,941	**1,022,051**
Total	**6,562,403**	**6,753,801**	**974,884**	**14,291,088**

Table 7.2 shows historical revenue requirement for 2018-2024 for the key components.

Table 7.2: Historical Gas Utility Revenue Requirement ($000) (2018-2024)

	2018	2019	2020	2021	2022	2023	2024
Core Procurement	2,067,169	2,226,842	1,822,180	2,475,283	3,804,455	4,868,952	2,374,364
Transportation	6,458,407	7,418,647	7,869,039	8,264,942	8,964,845	9,240,503	10,894,673
Public Purpose Programs	604,622	650,968	575,600	630,382	715,570	888,686	1,022,051
Total	**9,130,198**	**10,296,457**	**10,266,819**	**11,370,607**	**13,484,870**	**14,998,141**	**14,291,088**

As **Table 7.2** shows, the 2024 total natural gas utility costs decreased by 4.7 percent from 2023 compared to the 11.2 percent increase from 2022 to 2023.

Figure 7.1 shows the natural gas utility revenue requirements by components.

Figure 7.1: Historical Gas Utility Revenue Requirement Components ($ Billions)

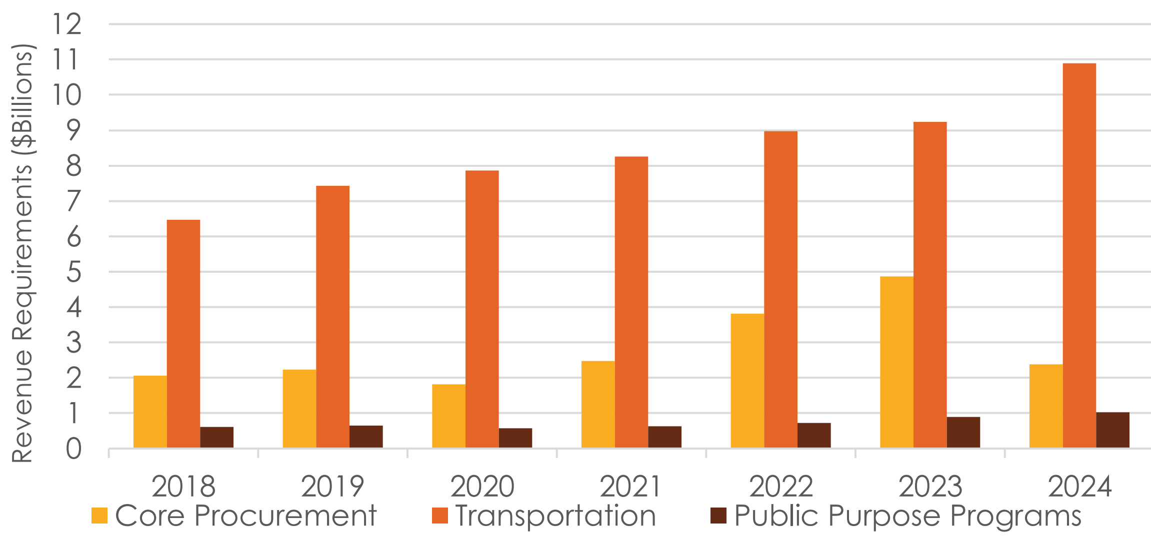


Table 7.3 shows the natural gas revenue requirement for each of the utilities from 2018-2024.

Table 7.3: Historical Revenue Requirement By Utility ($000)

	2018	2019	2020	2021	2022	2023	2024
PG&E	4,470,985	4,587,569	4,484,635	4,926,879	5,655,409	5,354,371	6,562,403
SoCalGas	4,113,388	5,042,690	5,009,906	5,637,250	6,832,542	8,418,390	6,753,801
SDG&E	545,825	666,198	772,278	806,478	996,919	1,225,380	974,884
Total	**9,130,198**	**10,296,457**	**10,266,819**	**11,370,607**	**13,484,870**	**14,998,141**	**14,291,088**

From 2023 to 2024, revenue requirements increased for PG&E but decreased for SoCalGas and SDG&E. PG&E's revenue requirement increased by 22.6 percent, while SoCalGas' and SDG&E's decreased by 19.8 percent and 20.4 percent, respectively.

Changes in the components of revenue requirement are summarized below and discussed in more detail in their respective sections.

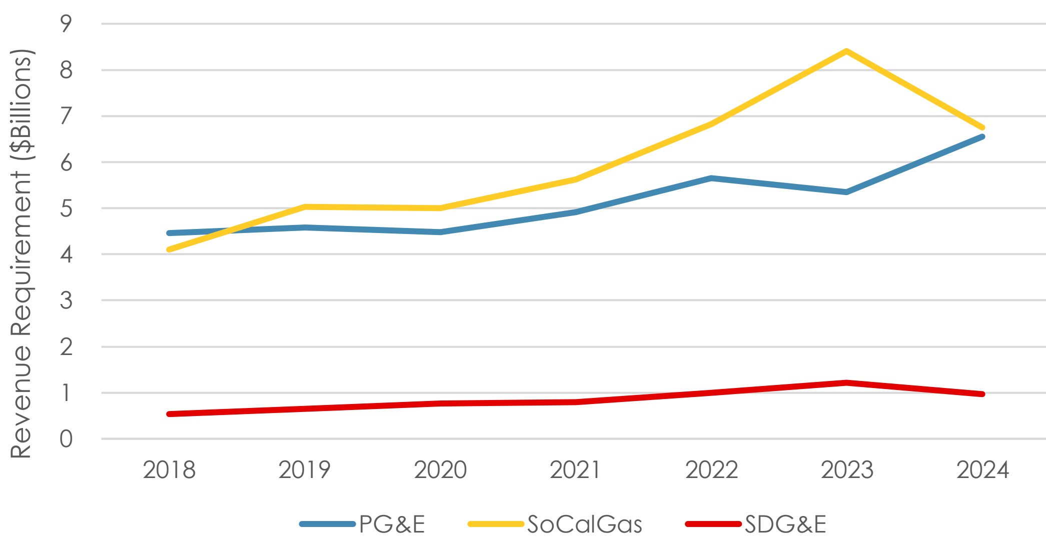
Total core procurement costs decreased by 51.2 percent from 2023 to 2024. PG&E saw an increase of 3.2 percent in core procurement costs, while SoCalGas saw a 65.2 percent decrease and SDG&E saw a 64.2 percent decrease.

Total transportation and distribution costs increased by 17.9 percent from 2023 to 2024. PG&E's transportation costs increased by 29.1 percent, while SoCalGas saw a 10 percent increase and SDG&E saw a 5.7 percent increase.

A third component of costs is the natural gas PPP costs, which increased by 15 percent from 2023 to 2024. PPP costs include expenditures for CARE and low-income energy-efficiency programs, which are designed to subsidize low-income households' utility bills. All three utilities saw an increase in PPP costs. PG&E's increased by 4.8 percent, SoCalGas's increased by 22 percent, and SDG&E's increased by 29 percent.

Figure 7.2 shows the trends in natural gas utility revenue requirements by utilities.

Figure 7.2: Historical Trends in Gas Utility Revenue Requirement ($ Billions)



Core Gas Procurement

The gas utilities recover the actual cost of procurement of natural gas for core customers through a rate component called the gas procurement rate. Core procurement costs include the various costs associated with procuring natural gas supplies for a utility's core gas customers, such as the cost of the commodity, interstate pipeline capacity costs, hedging costs, and other costs. However, the major component of core procurement costs is the cost of the commodity itself. The gas procurement rate changes every month to reflect the most current commodity prices for natural gas.

Pursuant to the Natural Gas Act of 1978 (NGA) and subsequent amendments, the cost of the natural gas commodity itself is deregulated. Neither the CPUC nor FERC regulate the wholesale price of natural gas. FERC regulates the cost of interstate transmission of natural gas to California, and the CPUC regulates the cost of intrastate transmission and distribution. FERC policy allows customers to resell such transportation rights bundled with the natural gas commodity at market rates.

FERC possesses broad powers under NGA Section 4A, added by the Energy Policy Act of 2005 (EPAct), to investigate and penalize anticompetitive behavior of the interstate natural gas transmission under its jurisdiction. FERC's enforcement powers also encompass broad market investigations into events with abnormally large consequences on gas and electric costs and reliability.

Core gas customers in California have the option to choose between utility gas procurement service and gas procurement service from other entities called Core Transport Agents (CTAs). CTAs are non-utility gas suppliers who purchase gas on behalf of residential and small commercial end-use customers. Even with CTAs, over 80 percent of core gas customers still receive gas procurement service from the utility. In contrast, all larger, noncore natural gas consumers (industrial customers or electric generators) procure their own natural gas supplies using non-utility suppliers.

The procurement costs shown in this section reflect only the utilities' costs of providing procurement service to core customers.

Due to a significant decrease in the price of natural gas since mid-2008 because of the rise in U.S. shale gas production, the state's natural gas utilities' procurement costs decreased by 40 percent from 2014 to 2020. However, core procurement costs have been volatile in recent years. On August 15, 2021, an interstate pipeline connecting Texas gas to Southern California ruptured and remained out of service until February 15, 2023. That loss increased competition for the remaining pipeline capacity, pushing up prices in Southern California. The Russian invasion of Ukraine on February 24, 2022, contributed to a period of rising natural gas prices across the country through the end of summer 2022 as the U.S. further ramped up exports of liquified natural gas (LNG) to compensate for reductions in Russian gas supplies to Europe. In California, a hot summer in 2022 was followed by a cold fall and winter, which contributed to high core procurement costs. Gas prices reached a peak in January 2023 but dropped considerably over the course of the year due to the return to service of the interstate pipeline, increases in natural gas production, high storage levels, and a mild winter both in California and nationally in 2023-2024.

Similar to how there are variations in the price of natural gas, there have been fluctuations in the demand for natural gas in recent years as well. Residential gas demand fluctuations are largely caused by weather while demand for gas for electric generation varies both due to weather and to the amount of hydroelectricity available in a given year. Gas demand impacts the revenue requirement because the utility needs to procure more supply to meet demand. For example, from 2022-2023, residential gas usage increased by 7 percent, while commercial usage increased by 4.4 percent. This contributed to an increase in revenue requirement because, in addition to gas being more expensive that year, the utilities had to procure more of it.

During the winter period of November 2022 – March 2023, natural gas prices in the western portion of the U.S. were extraordinarily high due to widespread below normal temperatures, high natural gas consumption, interstate natural gas pipeline constraints, lower imports from Canada, and low natural gas storage inventories in the Pacific Region[103]. Western natural gas prices started 2023 at the highest levels for the 2022-2023 winter and gradually decreased throughout 2023. By 2024, the conditions that led to the extraordinarily high prices in the 2022-2023 winter were resolved and prices were materially lower in 2024 compared to 2023. This led to natural gas prices that were lower in the months of January and February 2024 as compared to the same months in 2023.

Table 7.4 shows the average procurement rate to bundled core customers from January - March for 2023 and 2024 by utility.

Table 7.4: Average Procurement Rate to Bundled Core Customers By Utility

	PG&E	SoCalGas	SDG&E
January – March 2023	$12.33/MMBtu[104]	$17.09/MMBtu	$17.21/MMBtu
January – March 2024	$7.07/MMBtu	$6.11/MMBtu	$4.95/MMBtu

The higher costs seen in the first three months of 2023 were due in part to the harsh winter California experienced in 2022-2023. Procurement costs increased by 28 percent from 2022 to 2023. A milder winter in 2023-2024 contributed to natural gas prices that were lower for the first three months of 2024. These lowered procurement costs resulted in a total core gas procurement decrease of nearly $2.5 billion dollars, or 51.2 percent across all three IOUs from 2023 to 2024. This decrease from 2023 to 2024 resulted in a lower total procurement cost for 2024 than the total procurement cost for 2022 and 2023.

Table 7.5 and **Figure 7.3** show the historical revenue requirement for natural gas core procurement.

Table 7.5: Historical Core Procurement Revenue Requirement ($000)

	2018	2019	2020	2021	2022	2023	2024
PG&E	879,270	935,782	770,337	865,924	1,110,950	986,787	1,018,046
SoCalGas	1,048,393	1,134,044	923,497	1,417,147	2,365,840	3,408,039	1,186,439
SDG&E	139,506	157,016	128,346	192,212	327,665	474,126	169,879
Total	**2,067,169**	**2,226,842**	**1,822,180**	**2,475,283**	**3,804,455**	**4,868,952**	**2,374,364**

[103] EIA Natural Gas Weekly Update, December 22, 2022, available at: https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2022/12_22/.

EIA, Daily natural gas spot prices in western United States exceed $50.00/MMBtu in December, January 24, 2023, available at: https://www.eia.gov/todayinenergy/detail.php?id=55279.

[104] MMBtu = Million British Thermal Unit or roughly one dekatherm

Figure 7.3: Historical Natural Gas Core Procurement Revenue Requirement ($ Billions)

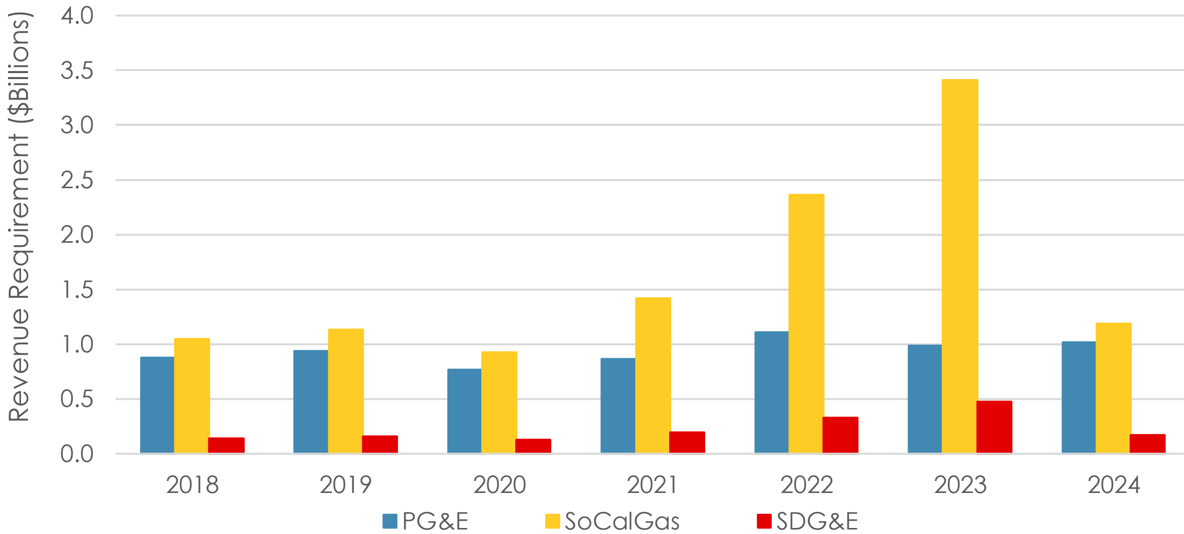


Table 7.6 shows the change in revenue requirement for core procurement.

Table 7.6: Percentage Change in Revenue Requirement for Core Procurement (2018-2024)

	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
PG&E	6.4%	(17.7%)	12.4%	28.3%	(11.2%)	3.2%
SoCalGas	8.2%	(18.6%)	53.5%	66.9%	44.1%	(65.2%)
SDG&E	12.6%	(18.3%)	49.8%	70.5%	44.7%	(64.2%)
Total	**7.7%**	**(18.2%)**	**35.8%**	**53.7%**	**28%**	**(51.2%)**

In 2024, core gas procurement costs accounted for 16.6 percent of total revenue requirement. **Table 7.6** shows an overcall core procurement decrease for all three IOUs, with an aggregate decrease of 51.2 percent. Changes in core procurement costs are primarily driven by commodity costs. PG&E saw a slight increase of 3.2 percent, while SoCalGas and SDG&E saw large decreases of 65.2 percent and 64.2 percent, respectively.

This decrease in aggregate core procurement cost across all three IOUs from 2023 to 2024 is notably lower than the increase seen from 2022 to 2023, in part due to lower procurement costs for SoCalGas and SDG&E.

PG&E saw a 44.3 percent decrease in Core Gas Supply Portfolio costs in 2024, however they also saw a 120.2 percent increase in their Core Gas Hedging[105] costs for 2024 which led to an overall core procurement cost increase of 3.2 percent from 2023 to 2024. Despite this slight increase the average procurement rate for 2024 was $4.78/MMBtu. This is a decrease from the average procurement rate for 2023 which was $6.35/MMBtu.

The increase in Core Gas Hedging costs was primarily due to the low natural gas prices experienced in the months of January and February 2024 as compared to the high natural gas prices during the same months in 2023. In the winter of 2022-2023, market prices settled at a higher price than the prices established by the program hedges. For example, the PG&E Citygate prices for January 2023 and February 2023 were $49.52 and $12.54, respectively. This resulted in PG&E receiving payouts from these hedges, contributing to the $414 million credit reported in the 2023 AB 67 Report and offsetting a portion of the gas cost increase for that winter. In the winter of 2023-2024, market prices during this time settled at lower prices than the prices established by the program hedges. For example, the PG&E Citygate prices for January 2024 and February 2024 were $4.29 and $5.43, respectively. This resulted in PG&E paying for these hedges, contributing to the $83 million charge that was reported for the 2024 AB 67 Report and which was offset by the gas cost decrease for the 2023-2024 winter.

SoCalGas's core procurement rate for 2024 saw a decrease of 65.2 percent as compared to 2023. The average procurement rate for 2024 was $3.5/MMBtu, a decrease from $7.94/MMBtu in 2023.

One of the main drivers of SoCalGas's decrease in core procurement costs from 2023 to 2024 was the decrease in Gas Cost Incentive Mechanism (GCIM) costs. On an annual basis, the GCIM compares the actual cost of the Utility Gas Procurement Department's purchases to an annual benchmark. The benchmark consists of the weighted average of published indices from independent gas industry publications and is a reflection of the natural gas wholesale market cost of gas for the trading points where the Utility Gas Procurement Department procures its gas supplies. Under benchmark dollars are generated when actual gas costs are less than the benchmark costs. Under benchmark costs are also subject to sharing between shareholders and ratepayers. The proposed 2024 $13.9 million[106] GCIM revenue requirement is $8.8 million less than the actual 2023 GCIM revenue requirement of $22.7 million.[107] The main drivers of the year-over-year GCIM decrease are consistent with the drivers for the decrease in the Core Gas Supply

[105] As approved in CPUC D.07-06-013 and modified in D.10-01-023, PG&E has a Long-Term Core Hedge Program. The program is intended to cap or fix the price that PG&E pays for natural gas to mitigate the impact of winter gas price increases on bundled core customer bills.

[106] SoCalGas notes that the $13.9 million GCIM Year 30 shareholder reward revenue requirement included in A.24-06-005 is part of an open CPUC proceeding and no final Decision approving the reward has been issued.

[107] The $62.8 million GCIM revenue requirement reported in the 2023 AB 67 report was reduced to $22.7 million as approved by the CPUC in D.24-10-007. In recognition of the confluence of market conditions and unprecedented high winter commodity prices that adversely affected customers' bills during GCIM Year 29, SoCalGas agreed to share $40.1 million of its calculated shareholder reward with core customers through procurement rates over the 2024-2025 winter period and agreed to reduce the shareholder reward to $22.7 million. The additional $40.1 million shareholder reward including interest was returned in procurement rates ratably over the period December 2024 – February 2025.

Portfolio. In 2023 SoCalGas saw high natural gas consumption, interstate natural gas pipeline constraints, lower imports from Canada, and low natural gas storage inventories in the Pacific Region. These conditions were exacerbated by the harsh winter experienced in 2022-2023. This led to extremely high natural gas prices for the beginning of 2023 that gradually decreased throughout the rest of the year. Due to the milder winter California experienced from 2023-2024, the conditions that led to these extraordinarily high prices no longer existed and led to a decrease in natural gas prices in 2024.

Another factor that contributed to the lower prices is an increase in storage capacity at Aliso Canyon. In August 2023, the CPUC voted unanimously to expand storage capacity at Aliso Canyon to 68.6 Bcf,[108] a more than 65 percent increase from the earlier expansion to 41.16 Bcf in November 2021. The site previously had a capacity of 86 Bcf, but this was reduced drastically after the historic 2015 methane leak.[109]

SDG&E saw a decrease of 64.2 percent in core procurement costs for 2024. SoCalGas manages SDG&E's gas portfolio and core procurement functions, so the reasons why SDG&E saw a large decrease in core procurement costs from 2023 to 2024 are similar to SoCalGas'. The primary factor was the milder winter experienced in 2023-2024 that led to lower market prices for natural gas in the first months of 2024 as compared to the first months of 2023.

For 2022-2023, PG&E had offset a significant amount of procurement costs through its winter hedging plan, where financial instruments are used to mitigate volatility in natural gas prices. In addition, PG&E's average procurement rate in 2023 decreased to $6.35/MMBtu, lower than $7.5/MMBtu in 2022.

In contrast, commodity prices in Southern California did not see a similar decrease, largely because its January 2023 core procurement price was so high. SoCalGas's average procurement rate in 2023 was $7.94/MMBtu compared to $7.85/MMBtu in 2022.

The increase seen from 2021 to 2022 was largely driven by commodity prices. For PG&E, however, because annual GRC revenue increases for core backbone and storage, such as that approved in D.19-09-025, that authorized PG&E's 2019-2022 Revenue Requirement for Gas Transmission and Storage Service. The costs are included in its core procurement rate, such increases contributed to the change in core procurement rate. For SoCalGas and SDG&E, storage costs are included in the transportation rate.

From 2020 to 2021 overall core procurement increased for each of the three IOUs, with an aggregate increase of 35.8 percent. The large increase in SoCalGas and SDG&E core procurement prices was due to increased commodity prices related in part to the easing of the pandemic and an increase in LNG exports combined with supply disruptions due to the outage on the El Paso interstate pipeline to Southern California that began on August 15, 2021.

From 2019 to 2020, overall core procurement decreased for each of the three IOUs, with an aggregate reduction of 18.2 percent. For PG&E, core procurement costs decreased due to reduced gas sales forecast

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[108] Bcf = Billion Cubic Feet

[109] D.23-08-050

volume and reduced commodity price. SoCalGas and SDG&E also saw decreases from 2019 to 2020 due to decreases in core consumption due to COVID-19, warmer weather, and lower commodity prices.

From 2018 to 2019, overall core procurement increased for each of the three utilities. The 7.7 percent increase in 2019 was due to the cold winter and the IOUs' spot market purchases. In 2019, core gas procurement costs accounted for about 22 percent of the total utility costs.

Gas Transmission, Distribution, and Storage Costs

The CPUC authorizes natural gas distribution utilities' revenue requirements for operating their extensive natural gas transmission, distribution, and storage systems safely and reliably, and for providing various customer services. These costs have steadily increased in recent years. The bulk of these revenue requirements are determined by the CPUC in the utilities' rate cases.

Table 7.7 shows historical revenue requirement for transportation for 2018-2024. With the recent emphasis on safety and replacement of aging infrastructure, the CPUC has authorized increased revenue requirement for all three major gas utilities with respect to transmission and distribution. Specifically, increases in total authorized revenue requirement for transmission, distribution, storage, and customer services, combined under the "transportation"[110] category, have increased by 68.7 percent from 2018 to 2024. Over the same time period, transportation costs increased by 53.9 percent for PG&E, 82.6 percent for SoCalGas, and 99.4 percent for SDG&E.

Table 7.7: Historical Transportation Revenue Requirement ($000)

	2018	2019	2020	2021	2022	2023	2024
PG&E	3,343,689	3,389,751	3,531,809	3,783,288	4,224,068	3,986,325	5,144,821
SoCalGas	2,741,585	3,550,769	3,723,109	3,896,051	4,117,214	4,550,164	5,005,788
SDG&E	373,133	478,127	614,121	806,478	623,563	704,014	744,064
Total	**6,458,407**	**7,418,647**	**7,869,039**	**8,264,942**	**8,964,845**	**9,240,503**	**10,894,673**

110 PG&E's authorized revenue requirement for storage is included in core procurement rate category.

Table 7.8 shows the change in revenue requirement for transportation.

Table 7.8: Percentage Change in Revenue Requirement for Transportation (2018-2024)

	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
PG&E	1.4%	4.2%	7.1%	11.7%	(5.6%)	29.1%
SoCalGas	29.5%	4.9%	4.6%	5.7%	10.5%	10.0%
SDG&E	28.1%	28.4%	(4.6%)	6.5%	12.9%	5.7%
Total	**14.9%**	**6.1%**	**5.0%**	**8.5%**	**3.1%**	**17.9%**

Transportation costs represented 76.2 percent of total utility gas costs in 2024. **Table 7.8** shows that aggregate gas transportation costs increased by 17.9 percent from 2023, driven by all three utilities' increases. PG&E's transportation costs increased by 29.1 percent, while SoCalGas' and SDG&E's increased by 10.0 percent and 5.7 percent, respectively.

There was a change in format requirements for reporting in the Transportation category for the 2024 AB 67 Report. This year utilities were required to specifically identify transmission revenue requirements under Transportation. In the 2023 AB 67 Report, the transmission revenue requirements were included as part of the Distribution category.

PG&E's transportation costs increased from 2023 to 2024 primarily due to increases in three categories, Hazardous Substance Mechanism (HSM), Other Balancing Accounts, and the Greenhouse Gas (GHG) Program.

HSM provides a uniform methodology for allocating costs and related recoveries associated with covered hazardous substance-related activities, including hazardous substance clean-up and litigation, and related insurance recoveries[111]. The expenses incurred in 2024 were higher than those incurred in 2023.

The Other Balancing Accounts category includes items that don't naturally fit into the other categories so it can vary significantly from year to year. The significant drivers of the increase from 2023 to 2024 were the

[111]As set forth in D.94-05-020 (the original HSM Decision) through the Hazardous Substance Cost Recovery Account (HSCRA). PG&E files Hazardous Substance Mechanism Annual Reports with the CPUC detailing the expenses incurred.

Residential Uncollectibles Balancing Account (RUBA)[112], property sales as authorized in D.21-08-027[113], GRC Track II, D.23-11-069 which was an increase of $101.7 million and authorized the recovery of the GRC Track II revenue requirements over two years, from January 1, 2024 through December 31, 2025, Wildfire Gas and Safety Costs Interim Rate Relief, D.24-03-006 which authorized recovery of $101.3 million in gas rates, and the GT&S Audit, D.22-07-001[114]. These increases were partially offset by a decrease in the Risk Transfer Balancing Account (RTBA), which had costs decreased by $177.5 million[115].

The GHG Proxy Prices used to calculate the GHG Costs and Credit increased significantly in 2024 compared to 2023, resulting in higher GHG Costs. The increase in costs was greater than the credit, leading to higher costs for the GHG Program in 2024 compared to 2023. Additional details can be seen in PG&E's 2023 and 2024 Annual Gas True-Up filings[116].

SoCalGas's increase in transportation costs from 2023 to 2024 were primarily due to the Gas Pipeline Integrity Management and Safety (TIMP), Pipeline Safety Enhancement Plan (PSEP), Other Balancing Accounts, and Greenhouse Gas (GHG) Program categories.

The increase in the Gas Pipeline Integrity Management and Safety (TIMP) category was due to the amortization of the TIMPBA undercollected balance pursuant to Advice No. (AL) 6060 and Resolution G-3600.

The PSEP category increase was due to the inclusion of the allocation of Backbone Transportation Service (BTS) costs attributable to the PSEP function. In the 2023 AB 67 Report, these BTS costs were included in the total revenue requirement under the Distribution category[117].

The increase in the Other Balancing Accounts category was primarily due to the increase in the amortization of the undercollected balance in the Residential Uncollectible Balancing Account (RUBA). In 2023,

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112 In 2023, PG&E received California Arrearage Payment Program (CAPP) funding to help offset past due utility bills from customers who were struggling during the COVID pandemic. This helped to offset the recorded RUBA balance in rates in 2023. PG&E did not receive CAPP funding in 2024 and as a result the RUBA balance increased by $122 million.

113 This reflects the sale of the San Francisco General Office. The credit in rates in 2023 reflected a decrease to rate base which was not included in the 2020 GRC rate base. Once the 2023 GRC was implemented in 2024 that credit was included as part of GRC base revenues. PG&E is reflecting the gain on sale as part of 'BA Other', so while still a credit to customers it was an increase in gas rates of approximately $40 million in 2024.

114 Note in the 2023 AB 67 Report the GT&S Audit costs were included in line II.b. of the report- GT&S Costs. In preparing in 2024, in order to provide more transparency around the 2023 GRC undercollection amount in rates it was decided to include the audit costs in the 'BA Other Category'. There is no actual change to the amount in rates for this program. The costs reflected are $61.1 million.

115 In 2023, PG&E was authorized to self-insure it wildfire risk. Those costs are collected through electric rates. The RTBA costs in rates in 2023 were related to incremental insurance costs for 2022.

116 For 2023 see Attachments 8, Tables A and C: pge.com/tariffs/assets/pdf/adviceletter/GAS_4693-G.pdf, For 2024 see Attachments 7, Tables A and C: GAS_4845-G.pdf

117 Line 2.a

SoCalGas amortized an undercollected balance of $45 million compared to amortizing an undercollected balance of $361 million in 2024.

For the GHG Program, the increase was primarily due to a higher proxy GHG Allowance Price forecast for 2024 compared to 2023.

SDG&E saw a smaller increase in transportation costs as compared to PG&E and SoCalGas. The increase was primarily due to increases in the Distribution category, specifically the Gas Pipeline Integrity Management and Safety (TIMP) and PSEP sub-categories, and the Greenhouse Gas (GHG) Program.

The increase in the Gas Pipeline Integrity Management and Safety (TIMP) was due to the amortization of the TIMPBA undercollected balance pursuant to Advice Letter (AL) 6060 and Resolution G-3600. The increase in the PSEP was due to the amortization of SEEBA undercollected balance pursuant to AL 3247-G-B. The increase in the GHG Program was primarily due to a higher proxy GHG Allowance Price forecast for 2024 compared to 2023.

PG&E's transportation costs decreased from 2022 to 2023 primarily due to a reduction in various balancing accounts. Most notably, $153 million in rates for the Wildfire Expense Memorandum Account were recovered in 2022, resulting in a decrease in 2023.[118] In addition, there was a net credit (or overcollection) of $97 million in 2023 as a result of a true-up of Gas Transmission and Storage related balancing accounts.[119] SoCalGas saw increases in Distribution costs primarily due to 2023 approved revenue requirement per the 2019 Sempra General Rate Case[120] and an adjustment to SoCalGas' revenue requirement in accordance with the Internal Revenue Service Private Letter Ruling.[121] In addition, costs increased compared to 2022 due to amortization of undercollected balances in various balancing accounts. For SDG&E, the main drivers for the increase were the implementation of revenue requirement and amortization of balancing accounts, as well as higher amortization of the Core Fixed Cost Account and Non-Core Fixed Cost Account.

The increase in transportation costs for PG&E from 2021 to 2022 was 11.7 percent, driven by increases from various balancing accounts, including the Wildfire Expense Memorandum Account (wildfire insurance related costs authorized for recovery), the Risk Transfer Balancing Account (recovery of incremental wildfire insurance costs), and the Residential Uncollectibles Balancing Account. SoCalGas and SDG&E saw smaller increases in transportation costs. For SoCalGas, the increase was driven by an increase in the GHG program costs and Low Emission Vehicle program costs. Similarly, SDG&E had increases in its GHG program costs.

From 2020 to 2021, the increase in transportation costs for PG&E was due to increases in "Other Balancing Account Balances" for costs of Distribution Integrity Management Program (DIMP) and the GHG Program. The increase in transportation costs for SoCalGas was due to increases in Distribution, DIMP,

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118 Approved in D.21-10-022 and AL 4529-G

119 See PG&E's 2023 Annual Gas True-Up AL 4693-G

120 D.19-09-051

121 SoCalGas AL 6018

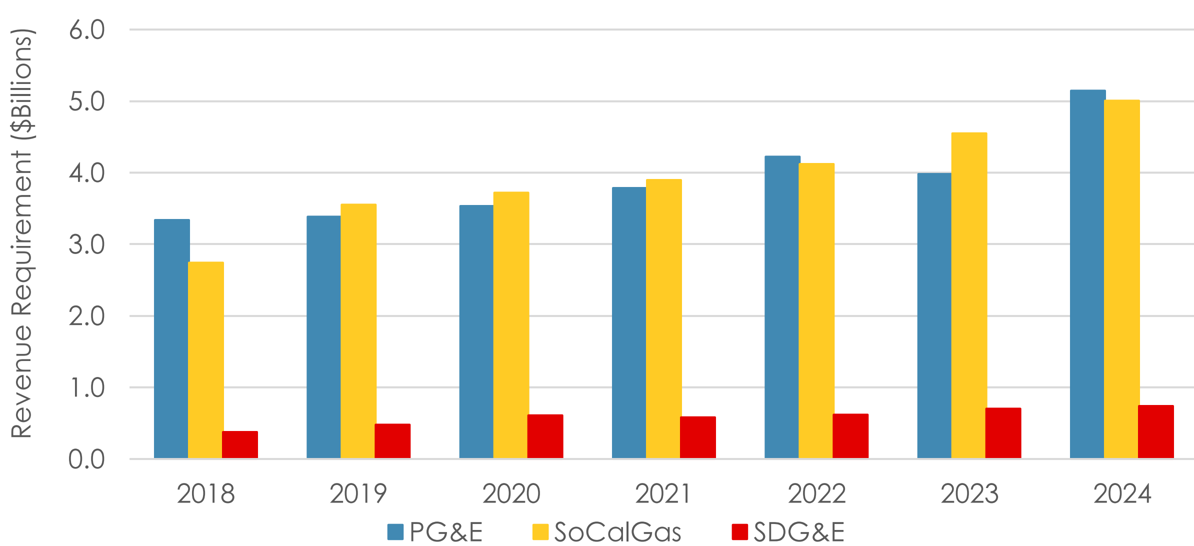
and Transmission Integrity Management Program (TIMP) costs. The decrease was transportation costs for SDG&E is due to a decrease in DIMP costs.

From 2019 to 2020, the increase in aggregate Transportation revenue requirement of the three IOUs was predominantly accounted for by an increase in "Other Balancing Account Balances" ($328 million) and in Distribution and DIMP taken together ($208 million). These were offset by smaller decreases in several programs that were part of the Transportation revenue requirement.

A major factor in the increase in total transportation costs for 2019 was that, for the first time for SoCalGas and SDG&E, GHG Program Costs and Proceeds (see further discussion below) were included in the transportation costs.

Figure 7.4 shows the historical revenue requirement for transmission, distribution, and storage.

Figure 7.4: Historical Natural Gas Transportation Revenue Requirement
($ Billions)



Legislative Program Costs

Several natural gas programs operated by the IOUs are under State mandates, apart from those under CPUC mandates. Among these, two large components are: (1) Greenhouse Gas Costs and Allowance Proceeds; and (2) Gas Public Purpose Program (PPP) Costs, discussed in detail below. Information on the applicable State Mandates (including PUC Sections) for covered programs is included in Appendix B for Gas Costs.

Table 7.9 shows the 2024 revenue requirement for State-Mandated natural gas programs.

Table 7.9: 2024 State Mandated Programs Revenue Requirement ($000)

Program Name	PG&E	SoCalGas	SDG&E	Total
Self-Generation Incentive Program (SGIP)	12,990	16,265	1,696	**30,951**
California Solar Initiative (CSI)	5,965	1,391	95	**7,451**
CPUC Fee[122]	4,532	0	0	**4,532**
Franchise Fee Surcharge (G-SUR)	6,398	66,475	3,373	**76,246**
Greenhouse Gas (GHG) Program	137,610	753,406	76,961	**967,977**
Energy Efficiency (EE) Programs	104,648	165,867	22,032	**292,547**
Low Income Energy Efficiency (LIFE)	70,669	111,508	7,006	**189,183**
Public Interest RD&D and State Board of Equalization (BOE) Administrative Fees	11,076	11,380	2,184	**24,640**
California Alternate Rates for Energy (CARE) Program	213,143	272,819	29,155	**515,117**
School Energy Efficiency Stimulus (SEES) Program	0	0	400	**400**
Total	**567,031**	**1,399,111**	**142,902**	**2,109,044**

[122] SDG&E and SoCalGas did not include the CPUC Fee in the revenue requirement reported here, but they do collect this fee as a separate charge on utility bills. As of December 2022, gas CPUC reimburse fees for PG&E, SDG&E, and SoCalGas are $0.003/therm (CPUC Resolution M-4866)

Greenhouse Gas Compliance Costs and Allowance Proceeds

Since January 1, 2015, natural gas utilities have been covered under California's Greenhouse Gas Cap-and-Trade Program. As covered entities under the program, the natural gas utilities must buy compliance instruments (offsets and allowances) and surrender them to the California Air Resources Board (CARB) to account for GHG emissions associated with the combustion or oxidation of fuels they provide to customers in California (less any amount delivered to covered entities that supply their own compliance instruments to CARB). CARB holds quarterly allowance auctions where entities can buy and sell allowances. The IOUs can also procure compliance instruments on secondary markets or through contractual arrangements.

CARB allocates some allowances to natural gas utilities on behalf of their ratepayers. The Cap-and-Trade Program requires the natural gas IOUs to sell an increasing share of these allowances at CARB's quarterly allowance auctions and use the proceeds for the benefit of ratepayers, starting at minimum of 25 percent of their allocated allowances in 2015 and increasing at a rate of 5 percent per year through 2030 (when 100 percent will be sold for ratepayer benefit). For 2024, natural gas utilities were required to sell 70 percent of allocated allowances for ratepayer benefit. The proceeds from the sale of GHG allowances must be used exclusively for ratepayer benefit, consistent with the goals of AB 32 (Nunez, Chapter 488, Statutes of 2006), CARB regulations, and as directed by the CPUC. The CPUC has determined the methodologies the utilities should use to return proceeds. D.15-10-032 and D.18-03-17 instructed natural gas utilities to return proceeds to residential ratepayers each April as an on-bill credit, with each residential ratepayer receiving an equal share of their utilities' available proceeds. Unlike 2023, in 2024 no Cap-and-Trade proceeds were used to fund programs maximizing benefits for residential ratepayers.

Beginning in 2015, the natural gas utilities started tracking Cap-and-Trade Program related costs and allowance proceeds. However, these costs and credits were not introduced into customer rates until July 1, 2018.[123] PG&E provided the 2018 credit in October 2018 and the 2019 credit in April 2019. SDG&E and SoCalGas distributed their 2018 and 2019 credits together in April 2019. All natural gas IOUs now typically distribute the natural gas California Climate Credit annually in April, absent other direction from the CPUC.

In 2024 the natural gas utilities collectively introduced approximately $1.45 billion in GHG costs into rates and returned approximately $986 million in allowance proceeds to customers (see **Table 7.10**). Costs are paid by nearly all customers on a per-therm basis, while benefits are directed solely towards residential ratepayers. As a result, while total gas Cap-and-Trade costs are higher than proceeds for 2024, the average IOU residential gas customer was a net beneficiary (between $5-$25) of the Cap-and-Trade Program in 2024.

[123] D.18-03-017 instructed the natural gas utilities to net compliance costs against proceeds for the 2015-2017 period and either (1) amortize costs over a 12-month period starting in July 2018 if costs exceeded proceeds or (2) distribute the net proceeds in 2018 as a climate credit if proceeds exceeded costs. D.18-03-017 also ordered that 2018 GHG compliance costs be amortized in rates over an 18-month period starting July 2018.

Table 7.10: 2024 Greenhouse Gas Costs and Allowance Proceeds[124]

	2024 Natural Gas GHG Revenue Requirement	2024 Natural Gas Proceeds Distributed to Customers
PG&E	$620,903,273	$440,353,596
SoCalGas	$753,237,450	$478,535,656
SDG&E	$76,920,358	$67,271,544
Total	**$1,451,061,081**	**$986,160,796**

Gas Public Purpose Program (PPP) Costs

The CPUC also authorizes costs for three main categories of gas PPPs: energy efficiency (EE) and low-income EE, the CARE subsidy, and the gas public interest research and development program administered by the CEC. Gas PPP costs are determined in various CPUC proceedings associated with the particular type of gas PPP. Gas PPP costs have increased since 2008 but are a relatively small part of total costs.

Gas PPP costs across all three IOUs increased by 15 percent from 2023 to 2024. These costs made up 7.2 percent of total revenue requirement in 2024.

In 2024 PG&E saw a 4.8 percent increase driven by increases in its Gas and Electric Energy Efficiency (EE) portfolio budget[125] and CARE program[126]. SoCalGas saw a 22 percent increase primarily due to increases in

[124] Revenue requirement and proceeds based on 2024 forecasted amounts.

[125] The PG&E EE gas Public Purpose Program revenue requirement increased in recent years in large part due to changes in the electric-gas splits applied to PG&E's EE portfolio budgets. The gas split increased in large part due to the relative increase in gas avoided cost benefits with the 2022 Avoided Cost Calculator (ACC), as described in PG&E's EE True-Up Advice Letter on page 28 found at pge.com/tariffs/assets/pdf/adviceletter/GAS_4814-G.pdf#page=30. In addition, the Energy Efficiency revenues include a balancing account balance true-up of the prior year's balance. There was a significant overcollection in rates in 2022 driving the total amount collected lower. The Energy Efficiency balance in rates in 2023 and 2024 was a small undercollection.

[126] There are three components to the amounts PG&E collects for CARE: CARE administrative fee, the estimated CARE discount and the CARE balancing account. The primary driver for the increase in costs for CARE is the balancing account which was overcollected in 2022 ($10 million) and then undercollected in 2023 ($23 million) and 2024 ($31 million). There was very little change in the CARE administrative costs or the CARE discount.

its LIEE and CARE programs[127]. SDG&E saw a 29 percent increase primarily due to its EE[128] and CARE program[129] costs.

Gas PPP costs are recovered through the gas PPP surcharge on core and non-exempt noncore customers.[130] Only non-CARE customers pay for the CARE subsidy portion of the gas PPP surcharge. The gas PPP surcharges are changed annually through advice letter filings, incorporating the revenue requirements for the gas PPPs adopted in CPUC proceedings.

Table 7.11 and **Figure 7.5** show the historical revenue requirement for public purpose programs.

Table 7.11: Historical Public Purpose Programs Revenue Requirement ($000)

	2018	2019	2020	2021	2022	2023	2024
PG&E	248,026	262,036	182,489	277,667	320,391	381,259	399,536
SoCalGas	323,410	357,877	363,300	324,052	349,488	460,187	561,574
SDG&E	33,186	31,055	29,811	33,204	52,680	47,240	60,941
Total	**604,622**	**650,968**	**575,600**	**634,923**	**722,559**	**888,686**	**1,022,051**

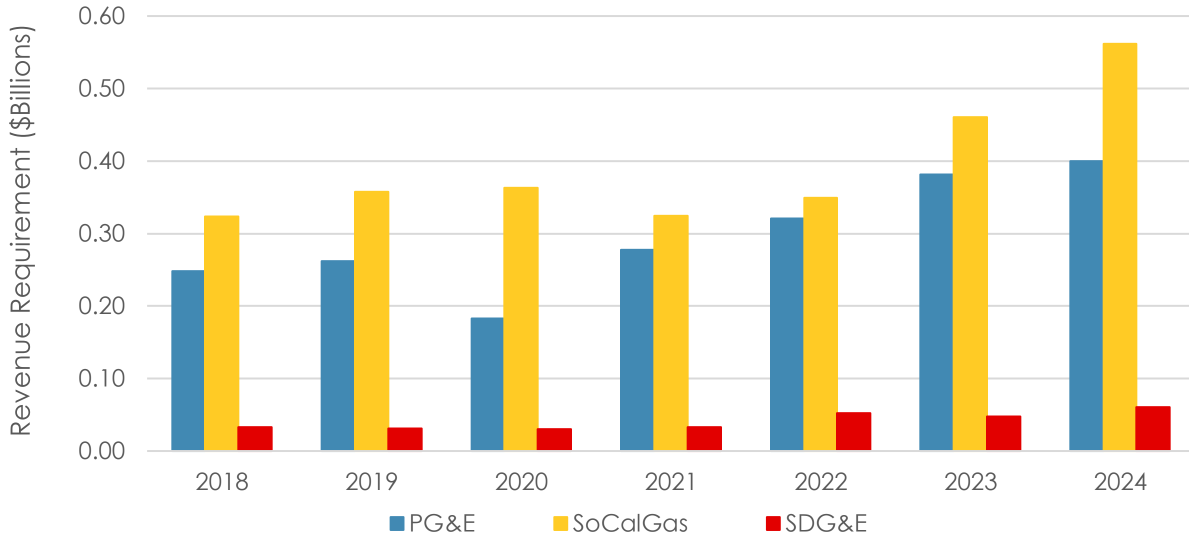
[127] As addressed on AL 6216, the 2024 PPP surcharge revenue requirement is higher by $101 million compared to the 2023 PPP surcharge revenue requirement. This is primarily due to an increase in the CARE costs of $72 million mostly due to a change from returning an over-collected balance in the CAREA in 2023 to recovering an under-collected balance in the CAREA in 2024.

[128] The increase to EE was pursuant to Decision (D.)23-06-055 Ordering Paragraph (OP) 5 for the 2024-2027 program portfolio funding.

[129] The increase to CARE is due to amortization of the undercollected balance pursuant to Advice Letter (AL) 3245-G.

[130] Noncore customers exempt from a gas PPP surcharge include electric generators, pursuant to Article 10 of the Public Utilities Code.

Figure 7.5: Historical Revenue Requirement for Gas Utility Public Purpose Programs ($ Billions)



Appendices

A digital copy of Appendices A and B can be found at:
https://www.cpuc.ca.gov/AB67Report

Appendix A: Historical Electric Revenue Requirements 2024-2018

2024 Revenue Requirements ($000)

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total			**5,223,556**	**5,069,512**	**991,446**
General Rate Case Revenues		CPUC Decisions	2,103,825	753,182	157,828
Transmission Total			**2,663,244**	**1,116,093**	**685,245**
Reliability Services	FERC Order 459		6,868	4,738	139.3075041
Transmission Access Charge	FERC		370,049	1,395,311	(277,788)
Transmission Owner Rate Case Revenues	FERC		2,293,963	0	1,003,495
Other - FERC Rate Case Revenues	FERC		(7,636)	(283,956)	(48,905)
Other			0	0	8,304
Distribution Total			**9,884,656**	**8,937,477**	**1,722,187**
General Rate Case Revenues		CPUC Decisions	9,884,656	8,937,477	1,722,187
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**(209,073)**	**6,830**	**1,443**
Demand Side Management and Customer Programs Total*			**775,339**	**873,847**	**310,727**
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	59,877	56,626	0

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
California Solar Initiative		CPUC Decisions	0	0	0
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	197,659	49,299	0
Energy Efficiency, PU Code 399.8	PUC Section 399.8	CPUC Decisions, E-3792	120,737	288,997	(31,000)
Energy Efficiency (non-PUC 399.8)			62,113	0	0
Electricity Program Investment Charge		CPUC Decisions	99,681	76,885	0
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	(7,595)	0	16,389
CARE Admin., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	(12,144)	64,318	6,242
Renewables	PUC Section 399.8	CPUC Resolution E-3792	0	0	852
Other PPP		CPUC Decisions, Resolutions	255,012	183,616	0
Other		CPUC Decisions, Resolutions	0	154,105	318,244
Other Regulatory Total*			**1,609,645**	**1,117,394**	**486,659**
Catastrophic Events (CEMA)	PUC Section 454.9(a)	CPUC Decisions	643,312	425,371	0
Hazardous Substance Mechanism		CPUC Decisions	45,960	0	0
CPUC Fee	PUC Section 431	CPUC Resolution M-4816	79,241	80,195	0
Other		CPUC Decisions, Resolutions	841,132	611,829	486,659
DWR Power Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**2,822**	**0**	**0**

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Wildfire Fund NBC	AB 1054	CPUC Decisions	**393,053**	**408,912**	**0**
Ongoing Competition Transition Charge	AB 57, PUC Section 367(a) & 369	CPUC Decisions	**0**	**0**	**9,780**
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	**(2,006)**	**0**	**0**
Franchise Fee Surcharge**	PUC Sections 6350-6354, 6231	CPUC Decisions	**0**	**0**	**25,583**
Electric Total	-	-	**20,341,236**	**17,530,066**	**4,233,072**
*Recovered in distribution rate component					
**Not reported elsewhere.					

Appendix A (cont.)

2023 Revenue Requirements ($000)

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total			**2,068,041**	**721,432**	**120,142**
General Rate Case Revenues		CPUC Decisions	2,068,041	721,432	120,142
Transmission Total			**3,272,496**	**1,354,762**	**860,184**
Reliability Services	FERC Order 459		41,540	(2,676)	550
Transmission Access Charge	FERC		492,205	1,513,894	(287,233)
Transmission Owner Rate Case Revenues	FERC		2,738,750	0	1,183,486
Other - FERC Rate Case Revenues	FERC		0	(156,456)	(42,437)
Other			0	0	5,817
Distribution Total			**6,470,495**	**7,359,386**	**1,674,791**
General Rate Case Revenues		CPUC Decisions	6,470,495	7,359,386	1,674,791
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**111,449**	**7,511**	**1,364**
Demand Side Management and Customer Programs Total*			**953,278**	**1,399,326**	**487,921**
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	59,895	56,626	0
California Solar Initiative		CPUC Decisions	0	0	0
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	75,060	39,005	10,852
Energy Efficiency, PU Code 399.8	PUC Section 399.8	CPUC Decisions, E-3792	120,737	405,006	117,574
Energy Efficiency (non-PUC			216,755	0	0

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
399.8)					
Electricity Program Investment Charge		CPUC Decisions	96,716	76,885	0
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	(34,850)	0	14,728
CARE Admin., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	189,668	(74,272)	79,000
Renewables	PUC Section 399.8	CPUC Resolution E-3792	0	0	55,075
Other PPP		CPUC Decisions, Resolutions	229,295	299,168	0
Other		CPUC Decisions, Resolutions	0	162,873	221,543
Other Regulatory Total*			**1,731,356**	**709,781**	**137,916**
Catastrophic Events (CEMA)	PUC Section 454.9(a)	CPUC Decisions	524,787	0	0
Hazardous Substance Mechanism		CPUC Decisions	33,349	0	128
CPUC Fee	PUC Section 431	CPUC Resolution M-4816	104,842	100,183	0
Other		CPUC Decisions, Resolutions	1,068,379	609,598	137,916
DWR Power Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**2,718**	**0**	**0**
Wildfire Fund NBC	AB 1054	CPUC Decisions	**378,336**	**402,302**	**75,465**
Ongoing Competition Transition Charge	AB 57, PUC Section 367(a) & 369	CPUC Decisions	**0**	**0**	**26,313**
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	**(56,973)**	**0**	**0**

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Franchise Fee Surcharge**	PUC Sections 6350-6354, 6231	CPUC Decisions	**0**	**0**	**23,151**
Electric Total			**17,759,988**	**17,530,315**	**4,387,451**
*Recovered in distribution rate component					
**Franchise fees for PG&E and SCE are captured in other line items.					

Appendix A (cont.)

2022 Revenue Requirements ($000)

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total			**4,245,003**	**5,093,206**	**1,119,102**
Qualifying Facilities	Federal PURPA, 1978; PUC Section 454.5(d)(3)	CPUC Decisions	167,655	2,304,369	20,216
General Rate Case Revenues		CPUC Decisions	2,068,041	694,344	184,078
Renewable Portfolio Standard	PUC Section 454.5(d)(3)	CPUC Decisions	2,136,532	Included with Qualifying Facilities	410,545
Other Utility Fuel & Purchased Power	PUC Section 454.5(d)(3)	CPUC Decisions	341,602	2,094,493	701,225
Other		CPUC Decisions, Resolutions	(468,826)	0	(196,963)
Transmission Total			**2,948,943**	**1,390,045**	**772,822**
Reliability Services	FERC Order 459		6,802	(66,884)	149
Transmission Access Charge	FERC		312,445	156,960	(275,612)
Transmission Owner Rate Case Revenues	FERC		2,629,695	1,412,489	1,064,885
Other - FERC Rate Case Revenues	FERC		0	(112,520)	(22,459)
Other			0	0	5,859
Distribution Total			**6,106,297**	**7,457,937**	**1,624,992**
General Rate Case Revenues		CPUC Decisions	6,106,297	7,457,937	1,624,992
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**42,628**	**7,827**	**1,358**

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Demand Side Management and Customer Programs Total*			**1,310,435**	**886,782**	**668,847**
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	59,819	56,000	0
California Solar Initiative		CPUC Decisions	0	0	0
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	71,802	28,031	12,766
Energy Efficiency, PU Code 399.8	PUC Section 399.8	CPUC Decisions, E-3792	120,737	318,470	0
Energy Efficiency (non-PUC 399.8)			115,467	0	35,349
Electricity Program Investment Charge		CPUC Decisions	41,163	75,098	0
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	(19,218)	0	4,222
CARE Admin., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	213,392	(30)	34,000
Renewables	PUC Section 399.8	CPUC Resolution E-3792	0	0	38,193
Other PPP		CPUC Decisions, Resolutions	201,939	253,444	234,958
Other		CPUC Decisions, Resolutions	505,334	155,769	309,359
Other Regulatory Total*			**461,224**	**578,891**	**12,790**
Catastrophic Events (CEMA)	PUC Section 454.9(a)	CPUC Decisions	332,441	0	0
Hazardous Substance Mechanism		CPUC Decisions	38,998	0	300
CPUC Fee	PUC Section 431	CPUC Resolution M-4816	100,624	100,183	0
Other		CPUC Decisions, Resolutions	(10,840)	478,708	12,490
DWR Power Charge	AB1X, Water Code,	CPUC Decisions	**(135,009)**	**0**	**0**

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Revenues	Division 27				
Wildfire Fund NBC	AB 1054	CPUC Decisions	**457,007**	**(143,910)**	**43,614**
Ongoing Competition Transition Charge	AB 57, PUC Section 367(a) & 369	CPUC Decisions	**0**	**0**	**19,093**
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	**(330,602)**	**0**	**0**
Franchise Fee Surcharge**	PUC Sections 6350-6354, 6231	CPUC Decisions	**0**	**(318)**	**9,028**
Electric Total			**15,105,926**	**15,270,459**	**4,271,646**
*Recovered in distribution rate component					
**Not reported elsewhere.					

Appendix A (cont.)

2021 Revenue Requirements ($000)

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total			**5,073,429**	**5,237,899**	**1,413,699**
Qualifying Facilities	Federal PURPA, 1978; PUC Section 454.5(d)(3)	CPUC Decisions	114,252	3,042,520	9,907
General Rate Case Revenues		CPUC Decisions	2,075,071	697,827	183,152
Renewable Portfolio Standard	PUC Section 454.5(d)(3)	CPUC Decisions	2,502,239	Included with Qualifying Facilities	659,328
Other Utility Fuel & Purchased Power	PUC Section 454.5(d)(3)	CPUC Decisions	380,681	1,481,544	643,541
Other		CPUC Decisions, Resolutions	1,185	16,009	(82,229)
Transmission Total			**2,035,538**	**1,253,026**	**736,175**
Reliability Services	FERC Order 459		10,316	(774)	(242)
Transmission Access Charge	FERC		57,898	258,290	(274,401)
Transmission Owner Rate Case Revenues	FERC		1,967,324	1,086,756	1,023,524
Other - FERC Rate Case Revenues	FERC		0	(91,246)	(21,410)
Other			0	0	8,704
Distribution Total			**5,595,486**	**6,587,686**	**1,599,694**
General Rate Case Revenues		CPUC Decisions	5,595,486	6,587,686	1,599,694
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**78,836**	**(43,059)**	**1,252**

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Demand Side Management and Customer Programs Total*			**504,703**	**529,779**	**468,880**
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	59,851	56,000	20,070
California Solar Initiative		CPUC Decisions	7,955	0	0
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	71,840	(1,706)	14,905
Energy Efficiency, PU Code 399.8	PUC Section 399.8	CPUC Decisions, E-3792	84,151	123,058	0
Energy Efficiency (non-PUC 399.8)			137,026	0	45,454
Electricity Program Investment Charge		CPUC Decisions	51,378	61,520	12,096
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	0	0	0
CARE Admin., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	176,631	112,992	130,081
Renewables	PUC Section 399.8	CPUC Resolution E-3792	0	0	0
Other PPP		CPUC Decisions, Resolutions	18,778	128,441	58,097
Other		CPUC Decisions, Resolutions	(102,908)	49,475	188,177
Other Regulatory Total*			**669,090**	**432,214**	**6,970**
Catastrophic Events (CEMA)	PUC Section 454.9(a)	CPUC Decisions	128,139	82,373	0
Hazardous Substance Mechanism		CPUC Decisions	35,480	0	80
CPUC Fee	PUC Section 431	CPUC Resolution M-4816	100,348	100,183	0
Other		CPUC Decisions, Resolutions	405,123	249,658	6,890

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
DWR Power Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**0**	**0**	**0**
Wildfire Fund NBC	AB 1054	CPUC Decisions	**403,357**	**388,714**	**90,159**
Ongoing Competition Transition Charge	AB 57, PUC Section 367(a) & 369	CPUC Decisions	**0**	**0**	**13,483**
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	**24,387**	**0**	**0**
Franchise Fee Surcharge**	PUC Sections 6350-6354, 6231	CPUC Decisions	**0**	**8,283**	**4,494**
Electric Total			**14,384,826**	**14,394,543**	**4,334,807**
*Recovered in distribution rate component					
**Not reported elsewhere.					

Appendix A (cont.)

2020 Revenue Requirements ($000)

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total			**5,514,686**	**5,514,150**	**1,507,396**
Qualifying Facilities	Federal PURPA, 1978; PUC Section 454.5(d)(3)	CPUC Decisions	183,050	3,124,621	6,701
General Rate Case Revenues		CPUC Decisions	2,238,948	735,315	183,153
Renewable Portfolio Standard	PUC Section 454.5(d)(3)	CPUC Decisions	1,851,969	Included with Qualifying Facilities	857,111
Other Utility Fuel & Purchased Power	PUC Section 454.5(d)(3)	CPUC Decisions	1,235,381	1,642,236	514,612
Other		CPUC Decisions, Resolutions	5,337	11,978	(54,182)
Transmission Total			**2,469,714**	**949,095**	**559,089**
Reliability Services	FERC Order 459		(36,546)	0	624
Transmission Access Charge	FERC		490,935	45,336	(287,001)
Transmission Owner Rate Case Revenues	FERC		2,015,324	962,976	858,000
Other - FERC Rate Case Revenues	FERC		0	(59,218)	(19,166)
Other			0	0	6,632
Distribution Total			**4,988,079**	**4,777,874**	**1,517,842**
General Rate Case Revenues		CPUC Decisions	4,988,079	4,777,874	1,517,842
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**89,909**	**(39,847)**	**1,048**

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Demand Side Management and Customer Programs Total*			**161,861**	**286,496**	**462,716**
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	59,851	56,637	20,070
California Solar Initiative		CPUC Decisions	7,955	0	0
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	74,097	21,483	14,736
Energy Efficiency, PU Code 399.8	PUC Section 399.8	CPUC Decisions, E-3792	98,941	46,541	0
Energy Efficiency (non-PUC 399.8)			(62,284)	0	71,388
Electricity Program Investment Charge		CPUC Decisions	97,834	76,900	16,280
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	71,412	65,808	13,145
CARE Admin., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	91,616	(8,531)	124,112
Renewables	PUC Section 399.8	CPUC Resolution E-3792	0	0	0
Other PPP		CPUC Decisions, Resolutions	18,300	(13,920)	52,512
Other		CPUC Decisions, Resolutions	(295,863)	41,578	150,473
Other Regulatory Total*			**439,683**	**98,209**	**8,064**
Catastrophic Events (CEMA)	PUC Section 454.9(a)	CPUC Decisions	301,787	51,626	0
Hazardous Substance Mechanism		CPUC Decisions	29,836	0	164
CPUC Fee	PUC Section 431	CPUC Resolution M-4816	47,117	46,584	0
Other		CPUC Decisions, Resolutions	60,943	0	7,900

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
DWR Power Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**(974)**	**(5,400)**	**(1,100)**
DWR Bond Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**427,327**	**428,069**	**66,926**
Ongoing Competition Transition Charge	AB 57, PUC Section 367(a) & 369	CPUC Decisions	**0**	**0**	**16,840**
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	**3,669**	**0**	**0**
Franchise Fee Surcharge**	PUC Sections 6350-6354, 6231	CPUC Decisions	**0**	**0**	**3,181**
Electric Total			**14,093,952**	**12,008,645**	**4,142,002**
*Recovered in distribution rate component					
**Not reported elsewhere.					

Appendix A (cont.)

2019 Revenue Requirements ($000)

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total			**5,388,555**	**5,926,553**	**1,668,615**
Qualifying Facilities	Federal PURPA, 1978; PUC Section 454.5(d)(3)	CPUC Decisions	181,551	2,719,189	7,566
General Rate Case Revenues		CPUC Decisions	2,156,844	670,615	244,650
Renewable Portfolio Standard	PUC Section 454.5(d)(3)	CPUC Decisions	1,931,130	Included with Qualifying Facilities	746,366
Other Utility Fuel & Purchased Power	PUC Section 454.5(d)(3)	CPUC Decisions	1,041,266	2,494,399	735,655
Other		CPUC Decisions, Resolutions	77,763	42,350	(65,622)
Transmission Total			**2,206,039**	**1,016,889**	**634,909**
Reliability Services	FERC Order 459		(24,241)	2,977	115
Transmission Access Charge	FERC		500,276	45,336	(265,539)
Transmission Owner Rate Case Revenues	FERC		1,736,739	1,039,554	900,051
Other - FERC Rate Case Revenues	FERC		(6,735)	(70,978)	(7,255)
Other			0	0	7,537
Distribution Total			5,004,292	3,881,203	1,296,667
General Rate Case Revenues		CPUC Decisions	5,004,292	3,881,203	1,296,667
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**79,414**	**(27,773)**	**(590)**

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Demand Side Management and Customer Programs Total*			**323,135**	**(38,479)**	**512,218**
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	59,851	55,998	20,069
California Solar Initiative		CPUC Decisions	7,955	3,840	2,002
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	68,419	37,997	11,838
Energy Efficiency, PU Code 399.8	PUC Section 399.8	CPUC Decisions, E-3792	92,009	92,892	0
Energy Efficiency (non-PUC 399.8)			73,624	0	104,038
Electricity Program Investment Charge		CPUC Decisions	89,885	76,095	17,138
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	129,493	63,617	5,829
CARE Admin., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	57,758	(1,288)	38,000
Renewables	PUC Section 399.8	CPUC Resolution E-3792	0	0	0
Other PPP		CPUC Decisions, Resolutions	3,381	(10,615)	123,934
Other		CPUC Decisions, Resolutions	(259,241)	(357,015)	189,369
Other Regulatory Total*			**70,252**	**46,584**	**5,270**
Catastrophic Events (CEMA)	PUC Section 454.9(a)	CPUC Decisions	4,800	0	0
Hazardous Substance Mechanism		CPUC Decisions	39,657	0	270
CPUC Fee	PUC Section 431	CPUC Resolution M-4816	48,009	46,584	0
Other		CPUC Decisions, Resolutions	(22,214)	0	5,000

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
DWR Power Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**(4,057)**	**(5,437)**	**(434)**
DWR Bond Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**376,681**	**366,979**	**77,388**
Ongoing Competition Transition Charge	AB 57, PUC Section 367(a) & 369	CPUC Decisions	**(136,983)**	**0**	**12,493**
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	**(46,396)**	**0**	**0**
Franchise Fee Surcharge**	PUC Sections 6350-6354, 6231	CPUC Decisions	**0**	**705**	**5,165**
Electric Total			**13,260,932**	**11,167,224**	**4,211,701**
*Recovered in distribution rate component					
**Not reported elsewhere.					

Appendix A (cont.)

2018 Revenue Requirements ($000)

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total			**5,668,922**	**5,934,570**	**1,822,448**
Qualifying Facilities	Federal PURPA, 1978; PUC Section 454.5(d)(3)	CPUC Decisions	182,537	2,594,336	43,088
General Rate Case Revenues		CPUC Decisions	1,981,324	750,267	242,986
Renewable Portfolio Standard	PUC Section 454.5(d)(3)	CPUC Decisions	2,068,222	Included with Qualifying Facilities	691,131
Other Utility Fuel & Purchased Power	PUC Section 454.5(d)(3)	CPUC Decisions	1,398,617	2,352,938	887,777
Other		CPUC Decisions, Resolutions	38,223	237,030	(42,534)
Transmission Total			**2,146,305**	**1,024,468**	**502,821**
Reliability Services	FERC Order 459		170,611	4,136	734
Transmission Access Charge	FERC		430,524	(26,963)	(304,074)
Transmission Owner Rate Case Revenues	FERC		1,556,910	1,162,882	813,492
Other - FERC Rate Case Revenues	FERC		(11,740)	(115,588)	(13,302)
Other			0	0	5,970
Distribution Total			**4,702,384**	**4,663,722**	**1,299,314**
General Rate Case Revenues		CPUC Decisions	4,702,384	4,663,722	1,299,314
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**22,625**	**4,400**	**(939)**

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Demand Side Management and Customer Programs Total*			**328,882**	**181,450**	**566,662**
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	59,849	55,998	0
California Solar Initiative		CPUC Decisions	8,292	6,000	0
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	41,271	42,854	19,358
Energy Efficiency, PU Code 399.8	PUC Section 399.8	CPUC Decisions, E-3792	120,806	312,268	0
Energy Efficiency (non-PUC 399.8)			251,626	0	112,520
Electricity Program Investment Charge		CPUC Decisions	96,989	69,840	47,060
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	82,946	62,540	16,684
CARE Admin., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	38,391	(3,259)	(7,000)
Renewables	PUC Section 399.8	CPUC Resolution E-3792	0	0	0
Other PPP		CPUC Decisions, Resolutions	(26,720)	18,112	93,832
Other		CPUC Decisions, Resolutions	(344,568)	(382,903)	284,208
Other Regulatory Total*			**74,607**	**0**	**1,318**
Catastrophic Events (CEMA)	PUC Section 454.9(a)	CPUC Decisions	0	0	0
Hazardous Substance Mechanism		CPUC Decisions	36,183	0	223
CPUC Fee	PUC Section 431	CPUC Resolution M-4816	38,133	0	0
Other		CPUC Decisions, Resolutions	292	0	1,095

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
DWR Power Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**(1,171)**	**0**	**0**
DWR Bond Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**408,607**	**406,524**	**91,076**
Ongoing Competition Transition Charge	AB 57, PUC Section 367(a) & 369	CPUC Decisions	**(79,700)**	**0**	**29,399**
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	**(3,773)**	**0**	**0**
Franchise Fee Surcharge**	PUC Sections 6350-6354, 6231	CPUC Decisions	**0**	**4,243**	**6,301**
Electric Total			**13,267,690**	**12,219,378**	**4,318,400**
*Recovered in distribution rate component					
**Not reported elsewhere.					

Appendix B: Historical Natural Gas Revenue Requirements 2024-2018

2024 Revenue Requirements ($000)

	Federal/State Mandate	CPUC Mandate	PG&E	SoCalGas	SDG&E
Core Procurement Total			**1,018,046**	**1,186,439**	**169,879**
Core Gas Supply Portfolio		CPUC Decisions	538,709	1,172,574	169,879
Other		CPUC Decisions	385,435	0	0
10/20 Winter Gas Savings		CPUC Resolutions	0	0	0
Core Gas Hedging		Report	83,693	0	0
Incentive Mechanism		Report	10,209	13,865	0
Transportation Total			**5,144,821**	**5,005,788**	**744,064**
Distribution		CPUC Decisions	2,730,283	2,582,477	522,948
Gas Pipeline Integrity Mgmt. (DIMP)			1,728,285	72,798	18,982
PSEP				135,091	49,368
SoCalGas Only - SIMP				24,352	
SoCalGas Only - Aliso Canyon					
Transmission		CPUC Decisions			
Gas Pipeline Integrity Mgmt. (TIMP)				174,513	17,864
PSEP				184,879	3,321
Advanced Metering Infrastructure		Report	0	0	0
Smart Meter			0	0	0
Self Gen Inc Prog (SGIP)	PUC Section 379.6 (a)	CPUC Decisions	12,990	16,265	1,696
Climate Smart			0	0	0
Calif Solar Initiative (CSI)		CPUC Decisions	5,965	1,391	95
Annual Earning Assessment		CPUC Decisions	(176)	7,370	0

	Federal/State Mandate	CPUC Mandate	PG&E	SoCalGas	SDG&E
(AEAP)					
Low Emission Vehicle (LEV)	PUC Section 740.3 & 740.8	CPUC Decisions	0	68,747	0
Haz Substance Mechanism (HSM)		CPUC Decisions	106,049	2,438	73
Performance Based Regulation (PBR)		CPUC Decisions, Resolutions	0	0	0
Customer Service & Safety Performance Indicator		CPUC Decisions, Resolutions	0	0	0
Non-Public Interest Research, Dvlp & Demo (RD&D)		CPUC Decisions	0	17,147	0
Core Pricing Flexibility Program		CPUC Decisions	0	111	0
Non-core competitive load growth program		CPUC Decisions	0	552	0
Catastrophic Event Memo Acct (CEMA)	PUC Section 454.9 (a), Res E-3238	CPUC Decisions, Resolutions	0	0	0
Z-Factor		CPUC Decisions	0	0	0
Other Balancing Accts Balances		Report	355,828	501,763	48,720
CPUC Fee	PUC Section 431	Resolution M-4816	4,532	0	0
Franchise Fees & Uncollectibles	PUC Section 6231	CPUC Decisions	9,298	0	0
Franchise Fee Surcharge (G-SUR)	PUC Sections 6350-6354	CPUC Resolutions	6,398	66,475	3,373
AB 32 Cap-And-Trade			47,759	14,883	663
GHG Program			137,610	753,406	76,961
			399,536	561,574	60,941
Public Purpose Program Surcharges Total	PUC Sections 399.8, 890-900	CPUC Decisions	**104,648**	**165,867**	**22,032**
Energy Efficiency (EE) Programs	PUC Sections 739.1, 890-900, 2790	CPUC Decisions	70,669	111,508	7,006
Low Income Energy Efficiency (LIEE)	PUC Sections 740, 890-900	CPUC Decisions	11,076	11,380	2,184
Public Interest RD&D and State Board of Equalization	PUC Sections 739.1 & .2, 890-	CPUC Decisions	213,143	272,819	29,155

	Federal/State Mandate	CPUC Mandate	PG&E	SoCalGas	SDG&E
(BOE)	900				
Calif Alternate Rates for Energy (CARE) Program	PUC Section 739.1		0	0	400
School Energy Efficiency Stimulus (SEES) Program	AB 841				
GAS TOTAL			**6,562,403**	**6,753,801**	**974,884**

Appendix B (cont.)

2023 Revenue Requirements ($000)

	Federal/State Mandate	CPUC Mandate	PG&E	SoCalGas	SDG&E
Core Procurement Total			**986,787**	**3,408,039**	**474,126**
Core Gas Supply Portfolio		CPUC Decisions	967,607	3,345,239	474,126
Other		CPUC Decisions	430,519	0	0
10/20 Winter Gas Savings		CPUC Resolutions	0	0	0
Core Gas Hedging		Report	(414,017)	0	0
Incentive Mechanism		Report	2,678	62,800	0
Transportation Total			**3,986,325**	**4,550,164**	**704,014**
Distribution		CPUC Decisions	2,081,103	3,362,210	495,144
Gas Pipeline Integrity Mgmt. (DIMP)			1,519,752	71,380	18,595
PSEP			0	101,953	39,079
SoCalGas Only - SIMP			0	59,860	
SoCalGas Only - Aliso Canyon			0		
Transmission		CPUC Decisions	0		
Gas Pipeline Integrity Mgmt. (TIMP)			0	58,682	10,550
PSEP			0	24,173	3,084
Advanced Metering Infrastructure		Report	0	-324	0
Smart Meter			0	0	0
Self Gen Inc Prog (SGIP)	PUC Section 379.6 (a)	CPUC Decisions	12,990	16,265	1,545
Climate Smart			0	0	0
Calif Solar Initiative (CSI)		CPUC Decisions	5,592	1,114	334
Annual Earning Assessment (AEAP)		CPUC Decisions	217	(289)	0
Low Emission Vehicle (LEV)	PUC Section 740.3	CPUC Decisions	0	146,497	0

	Federal/State Mandate	CPUC Mandate	PG&E	SoCalGas	SDG&E
	& 740.8				
Haz Substance Mechanism (HSM)		CPUC Decisions	77,816	441	123
Performance Based Regulation (PBR)		CPUC Decisions, Resolutions	0	0	0
Customer Service & Safety Performance Indicator		CPUC Decisions, Resolutions	0	0	0
Non-Public Interest Research, Dvlp & Demo (RD&D)		CPUC Decisions	0	17,147	0
Core Pricing Flexibility Program		CPUC Decisions	0	143	0
Non-core competitive load growth program		CPUC Decisions	0	493	0
Catastrophic Event Memo Acct (CEMA)	PUC Section 454.9 (a), Res E-3238	CPUC Decisions, Resolutions	0	0	0
Z-Factor		CPUC Decisions	0	0	0
Other Balancing Accts Balances		Report	117,017	176,122	69,290
CPUC Fee	PUC Section 431	Resolution M-4816	15,130	0	0
Franchise Fees & Uncollectibles	PUC Section 6231	CPUC Decisions	10,553	0	0
Franchise Fee Surcharge (G-SUR)	PUC Sections 6350-6354	CPUC Resolutions	12,721	57,777	4,981
AB 32 Cap-And-Trade			21,876	11,562	3,770
GHG Program			111,558	444,958	57,519
Public Purpose Program Surcharges Total	**PUC Sections 399.8, 890-900**	**CPUC Decisions**	**381,259**	**460,187**	**47,240**
Energy Efficiency (EE) Programs	PUC Sections 739.1, 890-900, 2790	CPUC Decisions	84,605	166,907	9,991
Low Income Energy Efficiency (LIEE)	PUC Sections 740, 890-900	CPUC Decisions	83,931	80,174	10,316
Public Interest RD&D and State Board of Equalization (BOE)	PUC Sections 739.1 & .2, 890-900	CPUC Decisions	11,848	12,265	2,278
Calif Alternate Rates for Energy	PUC Section		200,875	200,841	22,557

	Federal/State Mandate	CPUC Mandate	PG&E	SoCalGas	SDG&E
(CARE) Program	739.1				
School Energy Efficiency Stimulus (SEES) Program	AB 841		0	0	2,098
GAS TOTAL			**5,354,371**	**8,418,390**	**1,225,380**

Appendix B (cont.)

2022 Revenue Requirements ($000)

	Federal/State Mandate	CPUC Mandate	PG&E	SoCalGas	SDG&E
Core Procurement Total			**1,110.950**	**2,365,840**	**327,665**
Core Gas Supply Portfolio		CPUC Decisions	686,247	2,343,527	327,665
Other		CPUC Decisions	421,314	0	0
10/20 Winter Gas Savings		CPUC Resolutions	0	0	0
Core Gas Hedging		Report	(4,707)	0	0
Incentive Mechanism		Report	8,096	22,313	0
Transportation Total			**3,783,288**	**3,896,051**	**585,603**
Distribution		CPUC Decisions	2,094,595	3,143,713	469,428
Gas Pipeline Integrity Mgmt. (DIMP)			1,527,705	68,665	17,934
PSEP			0	98,973	38,689
SoCalGas Only - SIMP			0	23,651	0
SoCalGas Only - Aliso Canyon			0	0	0
Transmission		CPUC Decisions	0	0	0
Gas Pipeline Integrity Mgmt. (TIMP)			0	57,108	10,295
PSEP			0	23,827	3,036
Advanced Metering Infrastructure		Report	0	(77,757)	0
Smart Meter			0	0	0
Self Gen Inc Prog (SGIP)	PUC Section 379.6 (a)	CPUC Decisions	12,990	16,268	1,545
Climate Smart			0	0	0
Calif Solar Initiative (CSI)		CPUC Decisions	8,115	1,411	806
Annual Earning Assessment (AEAP)		CPUC Decisions	4,875	(267)	0
Low Emission Vehicle (LEV)	PUC Section 740.3	CPUC Decisions	0	136,377	0

	Federal/State Mandate	CPUC Mandate	PG&E	SoCalGas	SDG&E
	& 740.8				
Haz Substance Mechanism (HSM)		CPUC Decisions	90,018	284	291
Performance Based Regulation (PBR)		CPUC Decisions, Resolutions	0	0	0
Customer Service & Safety Performance Indicator		CPUC Decisions, Resolutions	0	0	0
Non-Public Interest Research, Dvlp & Demo (RD&D)		CPUC Decisions	0	16,765	0
Core Pricing Flexibility Program		CPUC Decisions	0	323	0
Non-core competitive load growth program		CPUC Decisions	0	1,066	0
Catastrophic Event Memo Acct (CEMA)	PUC Section 454.9 (a), Res E-3238	CPUC Decisions, Resolutions	0	0	0
Z-Factor		CPUC Decisions	0	0	0
Other Balancing Accts Balances		Report	302,489	108,574	17,757
CPUC Fee	PUC Section 431	Resolution M-4816	29,100	0	0
Franchise Fees & Uncollectibles	PUC Section 6231	CPUC Decisions	11,714	0	0
Franchise Fee Surcharge (G-SUR)	PUC Sections 6350-6354	CPUC Resolutions	15,955	28,403	3,800
AB 32 Cap-And-Trade			21,909	9,430	1,863
GHG Program			104,603	460,400	58,119
Public Purpose Program Surcharges Total	**PUC Sections 399.8, 890-900**	**CPUC Decisions**	**320,391**	**349,488**	**45,691**
Energy Efficiency (EE) Programs	PUC Sections 739.1, 890-900, 2790	CPUC Decisions	43,408	107,145	8,380
Low Income Energy Efficiency (LIEE)	PUC Sections 740, 890-900	CPUC Decisions	93,802	0	8,041
Public Interest RD&D and State Board of Equalization (BOE)	PUC Sections 739.1 & .2, 890-900	CPUC Decisions	11,454	12,955	1,930
Calif Alternate Rates for Energy	PUC Section		171,727	229,388	27,340

	Federal/State Mandate	CPUC Mandate	PG&E	SoCalGas	SDG&E
(CARE) Program	739.1				
School Energy Efficiency Stimulus (SEES) Program	AB 841		0	0	6,989
GAS TOTAL			**5,655,409**	**6,832,542**	**996,919**

Appendix B (cont.)

2021 Revenue Requirements ($000)

	Federal/State Mandate	CPUC Mandate	PG&E	SoCalGas	SDG&E
Core Procurement Total			**865,924**	**1,417,147**	**192,212**
Core Gas Supply Portfolio		CPUC Decisions	475,721	1,406,003	192,212
Other		CPUC Decisions	370,549	0	0
10/20 Winter Gas Savings		CPUC Resolutions	0	0	0
Core Gas Hedging		Report	16,136	0	0
Incentive Mechanism		Report	3,518	11,144	0
Transportation Total			**3,783,288**	**3,896,051**	**585,603**
Distribution		CPUC Decisions	2,130,066	2,971,090	442,148
Gas Pipeline Integrity Mgmt. (DIMP)			1,323,885	272,922	53,177
PSEP			0	184,223	36,113
SoCalGas Only - SIMP			0	23,096	0
SoCalGas Only - Aliso Canyon					
Transmission		CPUC Decisions	0	0	0
Gas Pipeline Integrity Mgmt. (TIMP)			0	105,021	17,064
PSEP			0	49,394	2,897
Advanced Metering Infrastructure		Report	0	0	0
Smart Meter			0	0	0
Self Gen Inc Prog (SGIP)	PUC Section 379.6 (a)	CPUC Decisions	12,990	16,272	1,545
Climate Smart			0	0	0
Calif Solar Initiative (CSI)		CPUC Decisions	13,138	5,979	816
Annual Earning Assessment (AEAP)		CPUC Decisions	5,343	(315)	0
Low Emission Vehicle (LEV)	PUC Section 740.3	CPUC Decisions	0	68,598	0

	Federal/State Mandate	CPUC Mandate	PG&E	SoCalGas	SDG&E
	& 740.8				
Haz Substance Mechanism (HSM)		CPUC Decisions	81,857	2,801	95
Performance Based Regulation (PBR)		CPUC Decisions, Resolutions	0	0	0
Customer Service & Safety Performance Indicator		CPUC Decisions, Resolutions	0	0	0
Non-Public Interest Research, Dvlp & Demo (RD&D)		CPUC Decisions	0	16,450	0
Core Pricing Flexibility Program		CPUC Decisions	0	333	0
Non-core competitive load growth program		CPUC Decisions	0	1,794	0
Catastrophic Event Memo Acct (CEMA)	PUC Section 454.9 (a), Res E-3238	CPUC Decisions, Resolutions	0	0	0
Z-Factor		CPUC Decisions	0	0	0
Other Balancing Accts Balances		Report	68,273	223,229	44,135
CPUC Fee	PUC Section 431	Resolution M-4816	29,100	0	0
Franchise Fees & Uncollectibles	PUC Section 6231	CPUC Decisions	7,576	0	0
Franchise Fee Surcharge (G-SUR)	PUC Sections 6350-6354	CPUC Resolutions	9,643	18,229	3,352
AB 32 Cap-And-Trade			(2,059)	9,591	2,058
GHG Program			103,476	184,057	25,333
Public Purpose Program Surcharges Total	PUC Sections 399.8, 890-900	CPUC Decisions	**277,667**	**324,052**	**28,663**
Energy Efficiency (EE) Programs	PUC Sections 739.1, 890-900, 2790	CPUC Decisions	78,051	109,736	1,677
Low Income Energy Efficiency (LIEE)	PUC Sections 740, 890-900	CPUC Decisions	22,922	0	0
Public Interest RD&D and State Board of Equalization (BOE)	PUC Sections 739.1 & .2, 890-900	CPUC Decisions	11,217	12,755	1,230
Calif Alternate Rates for Energy	PUC 739.1		165,477	201,561	25,756

	Federal/State Mandate	CPUC Mandate	PG&E	SoCalGas	SDG&E
(CARE) Program					
School Energy Efficiency Stimulus (SEES) Program	AB 841		0	0	4,541
GAS TOTAL			**4,926,879**	**5,637,250**	**806,478**

Appendix B (cont.)

2020 Revenue Requirements ($000)

	Federal/State Mandate	CPUC Mandate	PG&E	SoCalGas	SDG&E
Core Procurement Total			**770,337**	**923,497**	**128,346**
Core Gas Supply Portfolio		CPUC Decisions	388,032	910,691	128,346
Other		CPUC Decisions	370,475	0	0
10/20 Winter Gas Savings		CPUC Resolutions	0	0	0
Core Gas Hedging		Report	11,830	0	0
Incentive Mechanism		Report	0	12,806	0
Transportation Total			**3,531,809**	**3,723,109**	**614,121**
Distribution		CPUC Decisions	2,150,472	2,834,463	429,735
Gas Pipeline Integrity Mgmt. (DIMP)				56,726	16,208
PSEP				123,832	62,577
SoCalGas Only - SIMP				22,463	
SoCalGas Only - Aliso Canyon					
Transmission		CPUC Decisions	1,170,454	0	0
Gas Pipeline Integrity Mgmt. (TIMP)				31,559	9,023
PSEP				34,743	7,766
Advanced Metering Infrastructure		Report	0	0	0
Smart Meter			0	0	0
Self Gen Inc Prog (SGIP)	PUC Section 379.6 (a)	CPUC Decisions	12,990	16,271	2,060
Climate Smart			0	0	0
Calif Solar Initiative (CSI)		CPUC Decisions	8,477	22,759	1,401
Annual Earning Assessment (AEAP)		CPUC Decisions	2,937	304	0
Low Emission Vehicle (LEV)	PUC Section 740.3	CPUC Decisions	0	38,678	0

	Federal/State Mandate	CPUC Mandate	PG&E	SoCalGas	SDG&E
	& 740.8				
Haz Substance Mechanism (HSM)		CPUC Decisions	68,836	2,647	204
Performance Based Regulation (PBR)		CPUC Decisions, Resolutions	0	0	0
Customer Service & Safety Performance Indicator		CPUC Decisions, Resolutions	0	0	0
Non-Public Interest Research, Dvlp & Demo (RD&D)		CPUC Decisions	0	15,793	0
Core Pricing Flexibility Program		CPUC Decisions	0	688	0
Non-core competitive load growth program		CPUC Decisions	0	1,913	0
Catastrophic Event Memo Acct (CEMA)	PUC Section 454.9 (a), Res E-3238	CPUC Decisions, Resolutions	0	0	0
Z-Factor		CPUC Decisions	0	0	0
Other Balancing Accts Balances		Report	16,138	241,218	47,992
CPUC Fee	PUC Section 431	Resolution M-4816	29,100	0	0
Franchise Fees & Uncollectibles	PUC Section 6231	CPUC Decisions	6,994	0	0
Franchise Fee Surcharge (G-SUR)	PUC Sections 6350-6354	CPUC Resolutions	6,099	19,568	2,919
AB 32 Cap-And-Trade			24,294	9,696	2,286
GHG Program			35,018	249,788	31,950
Public Purpose Program Surcharges Total	PUC Sections 399.8, 890-900	CPUC Decisions	**182,489**	**363,300**	**29,811**
Energy Efficiency (EE) Programs	PUC Sections 739.1, 890-900, 2790	CPUC Decisions	70,279	93,255	812
Low Income Energy Efficiency (LIEE)	PUC Sections 740, 890-900	CPUC Decisions	(9,378)	134,474	11,572
Public Interest RD&D and State Board of Equalization (BOE)	PUC Sections 739.1 & .2, 890-900	CPUC Decisions	10,172	11,338	3,053

	Federal/State Mandate	CPUC Mandate	PG&E	SoCalGas	SDG&E
Calif Alternate Rates for Energy (CARE) Program			111,416	124,233	14,374
GAS TOTAL			**4,484,635**	**5,009,906**	**772,278**

Appendix B (cont.)

2019 Revenue Requirements ($000)

	Federal/State Mandate	CPUC Mandate	PG&E	SoCalGas	SDG&E
Core Procurement Total			**935,782**	**1,134,044**	**157,016**
Core Gas Supply Portfolio		CPUC Decisions	506,105	1,117,245	157,016
Other		CPUC Decisions	422,266	0	0
10/20 Winter Gas Savings		CPUC Resolutions	0	0	0
Core Gas Hedging		Report	4,848	0	0
Incentive Mechanism		Report	2,563	16,799	0
Transportation Total			**3,389,751**	**3,550,769**	**478,127**
Distribution		CPUC Decisions	2,085,766	2,796,303	402,360
Gas Pipeline Integrity Mgmt. (DIMP)				49.021	7,785
PSEP				83,110	35,910
SoCalGas Only - SIMP				28,103	
SoCalGas Only - Aliso Canyon					
Transmission		CPUC Decisions	1,178,640	0	0
Gas Pipeline Integrity Mgmt. (TIMP)				49,671	6,361
PSEP				27,391	
Advanced Metering Infrastructure		Report	0	21,750	0
Smart Meter			0	0	0
Self Gen Inc Prog (SGIP)	PUC Section 379.6 (a)	CPUC Decisions	12,990	16,270	1,545
Climate Smart			0	0	0
Calif Solar Initiative (CSI)		CPUC Decisions	7,358	25,492	1,834
Annual Earning Assessment (AEAP)		CPUC Decisions	612	258	0
Low Emission Vehicle (LEV)	PUC Section 740.3 & 740.8	CPUC Decisions	0	48,562	0

	Federal/State Mandate	CPUC Mandate	PG&E	SoCalGas	SDG&E
Haz Substance Mechanism (HSM)		CPUC Decisions	91,470	4,223	580
Performance Based Regulation (PBR)		CPUC Decisions, Resolutions	0	0	0
Customer Service & Safety Performance Indicator		CPUC Decisions, Resolutions	0	0	0
Non-Public Interest Research, Dvlp & Demo (RD&D)		CPUC Decisions	0	15,658	0
Core Pricing Flexibility Program		CPUC Decisions	0	1,619	0
Non-core competitive load growth program		CPUC Decisions	0	2,266	0
Catastrophic Event Memo Acct (CEMA)	PUC Section 454.9 (a), Res E-3238	CPUC Decisions, Resolutions	0	0	0
Z-Factor		CPUC Decisions	0	0	0
Other Balancing Accts Balances		Report	(76,948)	43,780	10,313
CPUC Fee	PUC Section 431	Resolution M-4816	11,661	0	0
Franchise Fees & Uncollectibles	PUC Section 6231	CPUC Decisions	6,849	0	0
Franchise Fee Surcharge (G-SUR)	PUC Sections 6350-6354	CPUC Resolutions	7,047	20,492	2,521
AB 32 Cap-And-Trade			25,403	9,264	615
GHG Program			38,903	307,536	8,303
Public Purpose Program Surcharges Total	PUC Sections 399.8, 890-900	CPUC Decisions	**262,036**	**357,877**	**31,055**
Energy Efficiency (EE) Programs	PUC Sections 739.1, 890-900, 2790	CPUC Decisions	64,668	102,319	10,996
Low Income Energy Efficiency (LIEE)	PUC Sections 740, 890-900	CPUC Decisions	78,343	131,837	6,436
Public Interest RD&D and State Board of Equalization (BOE)	PUC Sections 739.1 & .2, 890-900	CPUC Decisions	11,092	14,136	1,258
Calif Alternate Rates for Energy (CARE) Program			107,933	109,585	12,365
GAS TOTAL			**4,587,569**	**5,042,690**	**666,198**

Appendix B (cont.)

2018 Revenue Requirements ($000)

	Federal/State Mandate	CPUC Mandate	PG&E	SoCalGas	SDG&E
Core Procurement Total			**879,270**	**1,048,393**	**139,506**
Core Gas Supply Portfolio		CPUC Decisions	517,473	1,037,040	139,506
Other		CPUC Decisions	362,041	0	0
10/20 Winter Gas Savings		CPUC Resolutions	0	0	0
Core Gas Hedging		Report	(3,316)	0	0
Incentive Mechanism		Report	3,072	11,353	0
Transportation Total			**3,343,689**	**2,741,585**	**373,133**
Distribution		CPUC Decisions	1,964,824	2,331,772	325,765
Transmission		CPUC Decisions	1,281,236	0	0
Advanced Metering Infrastructure		Report	0	31,780	0
Smart Meter			0	0	0
Self Gen Inc Prog (SGIP)	PUC Section 379.6 (a)	CPUC Decisions	12,990	24,405	2,317
Climate Smart			0	0	0
Calif Solar Initiative (CSI)		CPUC Decisions	6,722	13,862	1,638
Annual Earning Assessment (AEAP)		CPUC Decisions	182	638	0
Low Emission Vehicle (LEV)	PUC Section 740.3 & 740.8	CPUC Decisions	0	52,872	0
Haz Substance Mechanism (HSM)		CPUC Decisions	83,469	1,396	520
Performance Based Regulation (PBR)		CPUC Decisions, Resolutions	0	0	0
Customer Service & Safety Performance Indicator		CPUC Decisions, Resolutions	0	0	0
Non-Public Interest Research, Dvlp & Demo (RD&D)		CPUC Decisions	0	12,924	0
Core Pricing Flexibility Program		CPUC Decisions	0	784	0

	Federal/State Mandate	CPUC Mandate	PG&E	SoCalGas	SDG&E
Non-core competitive load growth program		CPUC Decisions	0	1,795	0
Catastrophic Event Memo Acct (CEMA)	PUC Section 454.9 (a), Res E-3238	CPUC Decisions, Resolutions	0	0	0
Z-Factor		CPUC Decisions	0	0	0
Other Balancing Accts Balances		Report	10,526	28,610	6,261
CPUC Fee	PUC Section 431	Resolution M-4816	7,837	0	0
Franchise Fees & Uncollectibles	PUC Section 6231	CPUC Decisions	5,102	0	0
Franchise Fee Surcharge (G-SUR)	PUC Sections 6350-6354	CPUC Resolutions	5,842	22,589	2,057
AB 32 Cap-And-Trade			19,677	6,461	614
GHG Program	Sections 95851 (b), and 95852 (c) of Title 17	CPUC Decisions	(54,718)	-	-
Public Purpose Program Surcharges Total	**PUC Sections 399.8, 890-900**	**CPUC Decisions**	**248,026**	**323,410**	**33,186**
Energy Efficiency (EE) Programs	PUC Sections 739.1, 890-900, 2790	CPUC Decisions	57,823	74,527	11,931
Low Income Energy Efficiency (LIEE)	PUC Sections 740, 890-900	CPUC Decisions	75,742	129,252	16,002
Public Interest RD&D and State Board of Equalization (BOE)	PUC Sections 739.1 & .2, 890-900	CPUC Decisions	10,840	13,294	1,203
Calif Alternate Rates for Energy (CARE) Program			103,621	106,337	4,050
GAS TOTAL			**4,470,985**	**4,113,388**	**545,825**

Appendix C: Glossary

(A&G) Administrative and General Costs: The necessary costs to maintain a company's daily operations and administer its business. These costs are not directly attributable to the production of goods and services. Typical items include rent, legal counsel and accounting staff salaries, and office supplies.

(AB) Assembly Bill: A legislative bill sponsored or authored by an assemblymember.

Authorized Costs: The costs that utilities are permitted to charge their customers for their operations.

(BA) Balancing Account: An account used to match the collection of actual revenues against actual costs after an adjustment for unanticipated changes in expenditures. Fuel costs of major plant additions are often put into balancing accounts.

Bilateral Contract: An agreement between two parties in which each side agrees to fulfill their side of the bargain. A bilateral contract in an electricity market is an agreement between a willing buyer and a willing seller to exchange electricity, rights to generating capacity, or a related product under mutually agreeable terms for a specified period of time.

Bill: A draft of a proposed law introduced by a member of the legislature (Assembly Bill 4000, AB 4000, Senate Bill 1, SB 1).

Bundled IOU Customers: Customers that receive both generation and transmission/distribution from an IOU.

(Bundled SAR) Bundled System Average Rates: The average electric rate for bundled customers. These average rates are calculated by taking bundled revenue and dividing it by sales.

(CAISO) California Independent System Operator: The CAISO manages the flow of electricity across high-voltage, long-distance power lines, operates a competitive wholesale energy market, and oversees transmission planning.

Capital Expenditures: Funds used to buy, maintain, or improve fixed assets, such as buildings, vehicles, equipment, or land. Capital expenditures are often large and non-recurring, in contrast to operating expenses, which are often smaller and ongoing.

(CARB) California Air Resources Board: A state agency whose aim is to reduce air pollution and who oversees all air pollution control efforts in California. CARB sets the state's own emissions standards for a range of statewide pollution sources including vehicles, fuels and consumer products.

(CARE) California Alternate Rates for Energy Program: An energy rate assistance program that provides a discount on energy bills to income-qualified households. Electrical companies with 100,000 or more customer accounts in California offer a 30 percent to 35percent discount as required by PU Code Section 739.1. Electrical companies with fewer than 100,000 customer accounts in California offer a 20 percent discount. Natural gas customers enrolled in CARE receive a 20 percent discount on their natural gas bill.

(CCA) Community Choice Aggregator: Local government agencies that purchase and may develop power on behalf of residents, businesses, and municipal facilities within a local or sub-regional area.

(CEC) California Energy Commission: A state agency responsible for, among other things, forecasting future energy needs and keeping historical energy data, licensing thermal power plants 50 megawatts or larger, promoting energy efficiency through appliance and building standards, and developing energy technologies and supporting renewable energy. It is overseen by a Governor-appointed five-person board.

(CoC) Cost of Capital: The cost to a company of acquiring funds to finance its operations, including borrowed money, preferred stock dividends, etc.

Cogeneration or Co-Generation Facility: A facility that uses a heat engine or power station to generate electricity and useful heat at the same time. Cogeneration is a more efficient use of fuel or heat, because otherwise-wasted heat from electricity generation is put to some productive use.

(CPUC) California Public Utilities Commission: A state regulatory agency that regulates privately owned public utilities in the state of California, including electric, natural gas, telecommunications, water, railroad, rail transit, and passenger transportation companies.

(CPUC ED) California Public Utilities Commission Energy Division: A unit of the CPUC which assists in the regulation of electric, natural gas, steam and petroleum pipeline IOUs. CPUC ED develops and administers energy policy and programs, advises the CPUC, and ensures compliance with CPUC decisions and statutory mandates.

(CSGT) Community Solar Green Tariff: A program that enables residential customers in DACs who may be unable to install solar on their roof to benefit from a local solar project and receive a 20 percent bill discount.

(CSI) California Solar Initiative Program: An incentive program, established by D.06-01-024 and introduced by SB 1X (Murray, 2006), whose goal was the installation of 3,000 MW of solar by 2017. The CSI General Market Program closed on December 31, 2016.

Customer Generation: Customer-sited DER and related technologies. California allows customers to install renewable electrical generation facilities primarily to offset the customers' electrical needs, and to interconnect these facilities with the electrical grid.

(D.) Decision: An opinion or judgment which decides the resolution of a proceeding before the Commission. A proposed decision is usually written by an administrative law judge; it is then reviewed and voted upon by the Commissioners, usually at a regularly scheduled Commission meeting.

(DAC) Disadvantaged Community: A term referring to the areas throughout California that most suffer from a combination of economic, health, and environmental burdens. These burdens include poverty, high unemployment, health conditions like asthma and heart disease, as well as air and water pollution, and hazardous wastes.

(DAC-GT) Disadvantaged Communities – Green Tariff: A program that provides utility scale clean energy at a 20 percent bill discount for income-qualified, residential customers in DACs who may be unable to install solar on their roof.

(DAC-SASH) Disadvantaged Communities - Single-family Solar Homes Program: A program enabling income-qualified, single-family homeowners in DACs to receive no-cost rooftop solar installations.

Depreciation Costs: The reduction in the value of a fixed asset due to usage, wear and tear, the passage of time, or obsolescence. Depreciation is a standard accounting method that divides the upfront cost of physical assets across the number of years of expected use.

(DER) Distributed Energy Resources: In general usage, DERs are small-scale energy systems that power a nearby location. DERs can be connected to electric grids or isolated, with energy flowing only to specific sites or functions. The CPUC sometimes uses "DER" synonymously with "DSM" (Demand-Side Management) to encompass distribution-connected DG resources such as EE, DR, customer generation (e.g., rooftop solar), energy storage, alternative fuel vehicles (e.g., electric vehicles), and water-energy conservation.

(DG) Distributed Generation: Energy generation that occurs through DER. Also called Self-Generation, whereby consumers use small-scale power generation technologies (typically in the range of 3 to 10,000 kW) located close to where electricity is used (e.g., a home or business) to provide an alternative to or an enhancement of the traditional electric power system.

(DR) Demand Response: Reductions, increases, or shifts in electricity consumption by customers in response to their economic signals or reliability signals. DR programs aim to respond to these signals and maximize ratepayer benefit.

(DSM) Demand-Side Management: An approach to energy conservation that seeks to manage consumer demand for energy rather than merely supply it; a comprehensive strategy for managing electricity demand, incorporating financial incentives and developing educational programs designed to encourage energy efficiency and load reduction. The CPUC oversees programs and market mechanisms to help customer manage their energy use, and these include distribution-connected DG resources such as EE, DR, customer generation (e.g., rooftop solar), energy storage, alternative fuel vehicles (e.g., electric vehicles), and water-energy conservation. The CPUC sometimes uses "DER" synonymously with DSM.

(DWR) Department of Water Resources: A state agency responsible for the management of state water resources. In response to California's 2000-2001 energy crisis, DWR was authorized to purchase power to prevent rolling blackouts. DWR subsequently issued bonds to pay for the power it previously purchased and to establish operating and bond reserves to support the ongoing program. Annual revenue requirements for allocation to the IOU's customers, with bond and power charges, were put in place to pay for bond and power costs.

(EE) Energy Efficiency: Refers to programs that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided. These programs reduce overall electricity consumption (reported in megawatt-hours), often without explicit consideration for the timing of program-induced savings. Such savings are generally achieved by substituting technically more advanced equipment to produce the same level of end-use services.

(ERRA Proceeding) Energy Resource Recovery Account Proceeding: Energy Resource Recovery Account (ERRA) proceedings are used to determine fuel and purchased power costs which can be recovered in rates.

(ESA) Energy Savings Assistance Program: A program which provides no-cost weatherization and energy efficiency services to consumers who meet the CARE or FERA income limits. Services and measures provided include attic insulation, energy-efficient refrigerators, energy-efficient furnaces, weatherstripping, caulking, low-flow showerheads, water heater blankets, and door and building envelope repairs, which reduce air infiltration.

(ESP) Electric Service Providers: An entity that offers electrical service to commercial and industrial customers within the service territory of an electrical corporation and includes the unregulated affiliates and subsidiaries of an electrical corporation.

(FERA) Family Electric Rate Assistance Program: An energy rate assistance program designed to assist families whose household income slightly exceeds the CARE program limits. FERA provides an 18 percent discount on electric bills.

(FERC) Federal Energy Regulatory Commission: An independent regulatory body within the federal Department of Energy which regulates interstate gas and electric rates and facilities, as well as hydroelectric plant licenses.

GHG Cap-and-Trade Program: An emissions trading system that set a statewide greenhouse gas emissions cap and will lower that limit each year until California reaches its emissions reduction goals. Electricity companies that import or supply electricity from non-renewable sources must purchase permits for the greenhouse gas emissions that come from burning fuel to make this electricity. When natural gas utilities sell to customers, they must pay for emissions associated with customer burning of these fuels and pass these costs on through customers' bills in their gas transportation rates.

(GHGs) Greenhouse Gases: A category of gases that absorb a significant amount of heat energy emitted from the planet's surface and re-radiate some of it back toward the surface. GHGs trap heat near the Earth's surface. Carbon dioxide (abbreviated as CO_2) is one such gas.

(GRC) General Rate Case: A proceeding in which the CPUC takes a broad, in-depth look at a utility's revenues, expenses, and financial outlook and considers quality of service and other factors to arrive at just and reasonable rates. These are the major regulatory proceedings that come before the CPUC.

(GWh) Gigawatt Hour: A unit of measurement for energy usage, it represents the energy delivered by one gigawatt of power (or one billion watts) for one hour. GWh are mostly used as a measurement of the output of large electric power stations.

Inter-Utility or Power Exchange Agreement: a seasonal and long-term exchange agreement entered into between a regulated utility and another regulated utility or other load serving entity. Payment is typically in the form of non-cash exchanges of capacity and energy balanced to reflect the seasonal and locational value of the power.

(IOU) Investor-Owned Utilities: IOUs are privately owned electricity and natural gas providers and are regulated by the CPUC. PG&E, SCE, and SDG&E comprise approximately 40 percent of the retail electricity supply in California.

(kV) Kilovolt: A unit of measurement for electric potential. A kV measures how much electricity can be pushed through a circuit. Electric utilities use the unit to measure voltage in high-voltage transmission lines.

(KWh) Kilowatt Hour: A unit of measurement for energy usage, it represents the energy delivered by one kilowatt of power (or one thousand watts) for one hour. KWhs are a common billing unit for electrical energy supplied by electric utilities.

(LIOB) Low Income Oversight Board: An advisory body established in 2001, LIOB advises the CPUC on low-income electric and gas customer issues and serves as a liaison for the CPUC to low-income ratepayers and representatives.

(MA) Memorandum Account: An account that, after approval by the CPUC or upon statutory notice, may be used by a utility to track various revenues it accrues and expenses it incurs, including, but not limited to, capital costs and associated interest. The utility may later seek authorization from the CPUC for disposition of the tracked amounts through rates.

(MMTh) Million-therms: a unit of measurement used to express the CPUC's adopted savings goals for natural gas.

(MW) Megawatt: A unit of power equal to one million watts. It is commonly used to measure the power output of large power plants, wind turbines, solar farms, and other large-scale power generation equipment.

(NEM) Net Energy Metering: Under NEM tariffs, participating customers receive bill credits for excess generation that is exported to the electric grid during times when it is not serving onsite load. These bill credits are applied to customers' monthly bills at the retail rates (including generation, distribution, and transmission components) that the customers pay for energy consumption according to their otherwise applicable rate structures. These tariffs are closed to new enrollments.

(O&M) Operations and Maintenance Costs: The costs involved in the day-to-day operations and maintenance of assets, facilities, projects, or infrastructure. These expenses include routine maintenance, equipment repairs, utility bills, labor costs, and other related expenditures. O&M costs tend to be ongoing costs.

(OIR) Order Instituting Rulemaking: An investigatory proceeding opened by the CPUC to consider the creation or revision of rules or guidelines in a matter affecting more than one utility or a broad sector of the industry. Comments and proposals are submitted in written form. Oral arguments or presentations are sometimes allowed. The CPUC's decision is often implemented in a General Order (GO).

(PCIA) Power Charge Indifference Adjustment: Charge to customers that departed a utility for costs that utility incurred in anticipation of serving the customers to ensure remaining customers are not burdened by the departure of those customers.

(PURPA) Public Utility Regulatory Policies Act: A federal act enacted in 1978 and meant to promote energy conservation and greater use of domestic energy and renewable energy. PURPA attempted to accomplish its goals by creating a new class of electric generating facilities called "qualifying facilities".

(QF) Qualifying Facilities: As defined in PURPA, a cogeneration facility or small power production plant that can sell its electricity to public utilities.

(RA) Resource Adequacy: The ability of a utilities' reliable capacity resources (supply) to meet customers' energy or system loads (demands) at all hours.

Rate Base: This is generally calculated by adding up the original cost of all the physical assets and then subtracting the accumulated depreciation and deferred income tax.

Real-Time Market: A spot market in which utilities can buy power to meet the last few increments of demand not covered in their day-ahead schedules. It is also the market that secures energy reserves, held ready and available for ISO use if needed, and the energy needed to regulate transmission line stability.

(REC) Renewable Energy Credit: A market-based instrument that represents the property rights to the environmental, social and other non-power attributes associated with the production of electricity from a renewable source. RECs play an important role in driving the deployment of renewable energy in California and achieving the goals of RPS. A REC confers to its holder a claim on the renewable attributes of one unit of energy (MWh) generated from a renewable resource. RECs are "created" by a renewable generator simultaneous to the production of electricity and can subsequently be sold separately from the underlying energy.

Revenue Requirement: The amount that each electric utility can collect from its customers. The revenue requirement is based on the cost of operating, maintaining, and financing the infrastructure used to run the utility, and on the cost of its procured fuel and power.

(ROE) Return on Equity: The profits distributed to common shareholders after all expenses, interest costs, and preferred stock dividends have been paid. In ratemaking, it represents the level of revenue needed that will permit equity stockholders the opportunity to earn a fair return on their investment in the utility.

(ROR) Rate of Return: This figure, which is expressed as a percentage, reflects the utility's weighted cost of capital.

(RPS Program) Renewables Portfolio Standard Program: California's RPS program was established in 2002 by SB 1078 (Sher, 2002) with the initial requirement that 20 percent of electricity retail sales must be served by renewable resources by 2017. The program was accelerated in 2015 with SB 350 (de León, 2015) which mandated a 50 percent RPS by 2030. SB 350 includes interim annual RPS targets with three-year compliance periods and requires 65 percent of RPS procurement to be derived from long-term contracts of 10 or more years. In 2018, SB 100 (de León, 2018) was signed into law, which again increases the RPS to 60 percent by 2030 and requires all the state's electricity to come from carbon-free resources by 2045.

(SB) Senate Bill: A legislative bill sponsored or authored by a state senator.

(SGIP) Self-Generation Incentive Program: A program that provides incentives to support existing, new, and emerging DER. SGIP provides incentives for qualifying distributed energy systems installed on the customer's side of the utility meter. Qualifying technologies include wind turbines, waste heat to power technologies, pressure reduction turbines, internal combustion engines, microturbines, gas turbines, fuel cells, linear generators, advanced energy storage systems, and combined solar and energy storage systems.

(SOMAH) Solar on Multifamily Affordable Housing Program: A program that provides financial incentives for the installation of solar energy photovoltaic systems on multifamily affordable housing properties throughout California. AB 693 (Eggman, 2015) established SOMAH in PU Code 2870.

Spot Market: The trade of financial instruments for immediate payment and delivery. Assets traded in the spot market include commodities, currencies, and securities. In the context of electric utilities, a commodity market for the purchase and sale of electric energy for a short-term basis (often one day or less.)

Spot Market Purchase: In the context of electric utilities, power that the IOUs buy from the CAISO's Day-Ahead market to balance the system on a day-to-day basis.

Therm: A unit of heat equal to 100,000 British thermal units (Btu). The heat content of natural gas is usually measured in therms rather than cubic feet because gas from different sources may have different heating values.

Transmission Owner: An entity who builds, owns, operates, and maintains transmission infrastructure. The majority of California transmission infrastructure is owned by the three large IOUs while the remaining transmission is owned by municipal utilities, joint powers authorities, independent transmission developers and the Western Area Power Administration.

(TRR) Transmission Revenue Requirement: The total cost of providing transmission service, including construction, maintenance, and operation of transmission infrastructure, as well as rate of return on associated capital investments.

(UOG) Utility-Owned Generation: Generation facilities owned by the utilities (or retail seller).

Appendix D: 913.9 Report

PUBLIC UTILITIES CODE (PUC) 913.9

Commission (CPUC) Energy Efficiency Program Duplication Analysis Biennial Report

Published September 2025

California Public Utilities Commission

Contents

Summary

PUC 913.9 mandates the CPUC (the commission), in its annual report prepared pursuant to Section 913, identify and report to the Legislature on electrical and gas corporation ratepayer-funded energy efficiency programs that are similar to programs administered by the California Energy Commission, the California Air Resources Board, and the California Alternative Energy and Advanced Transportation Financing Authority, and on those programs revised pursuant to Section 381.4. The analysis results have shown that **no duplicative EE program has been identified** between the program administrators (PAs), which include PG&E, SCE, SDG&E, and SCG, and the above sister state agencies, for the 2023 program year. However, the analysis did find program overlaps exist.

Background

PUC 913.9 mandates the commission, in its annual report prepared pursuant to Section 913, biennially identify and report to the Legislature on electrical and gas corporation ratepayer-funded energy efficiency programs that are similar to those administered by the Energy Commission (CEC), the State Air Resources Board (CARB), and the California Alternative Energy and Advanced Transportation Financing Authority (CAEATFA).

The PUC 913.9 reporting requirements apply to electrical corporations with at least 1,000,000 retail customers in California and gas corporations with at least 500,000 retail customers in California. Thus, the qualified program administrators are PG&E, SCE, SDG&E, and SCG.

Methodology

To comply with PUC 913.9, the Commission's Energy Division staff identified a total of 31 energy efficiency programs from our sister agencies' websites for the 2023 program year. Below is a summary table for the count of sister agency programs:

Table1: Summary of Sister Agency's Program Count

Sister Agency	Count of Programs
CAEATFA	7
CARB	8
CEC	16
Grand Total	31

To determine whether a program administered by the commission is duplicative with a sister agency program, Energy Division staff used a systematic evaluation process. The process includes the following steps:

1) Compile a list of existing programs during 2023 for both sister agency programs and the commission programs.
2) Review program descriptions, objectives, and target customers: Examine the objectives and target customers of each program. Identify the specific goals they aim to achieve and the demographic or sector they serve (e.g., residential, commercial, industrial).
3) Examine funding sources and budgets: Review the funding sources and budgets of each program. Identify any sources of funding duplication or inefficient allocation of resources.
4) Engage stakeholders: Consult with stakeholders, including program administrators, policymakers, industry experts, etc. Gather input on program performance, identify areas of overlap or redundancy.

Energy Division staff developed an indicator system primarily based on the following criteria during the systematic evaluation process to select the best candidates from the commission programs "Table 2: Indicator System" shows as below:

Table 2: Indicator System

Criteria	Description
EE Program Name	The name of a Program that reduces customer energy use by promoting energy efficiency investments or the adoption of conservation practices or changes in operation which maintain or increase the level of energy services provided to the customer.
Program Category	The classification or grouping of energy efficiency initiatives or activities based on their objectives, target audience, or implementation strategies. The primary category includes Audit, Codes and Standards, Emerging Technologies, Energy Savings Assistance, Energy Savings Performance Incentive, Workforce Education and Training, etc.
Program Sector	The particular area or industry is targeted by an energy efficiency program or initiative. The primary sectors include Agricultural, Commercial, Industrial, Residential, Public, Cross-Cutting, etc.
CPUC Funding Role/Oversight	The commission's role in funding and oversight related to energy efficiency initiatives and programs
Program Status	The current condition or stage of a program. The primary status includes New, Active, Closure pending, Closed, Transitioning, Closed to new commitments, etc.
Program Description	The overview of the objectives, activities, target audience, and outcomes of a particular program or initiative.
Program Goals	The overarching objectives and desired outcomes that a particular initiative or project aims to achieve.
Service Provided	The specific offerings, assistance, or support provided by a program,
Target Customers	The specific individuals, households, businesses, or organizations that a program, or service is designed to serve. The target customers are those who are identified as the primary beneficiaries or intended participants of the program.

Energy Division staff first collected the information on the above nine indicators for each of the 31 sister agency programs from their websites. Then, the Energy Division staff reviewed hundreds of energy efficiency program identification numbers filed with the commission by the qualified program administrators.

Next, Energy Division staff compared the sister agency programs with dozens of CPUC programs with program information stored in the California Energy Data and Reporting System (CEDARS) (see the second last column of Appendix1: Sister Agency Program List) that share similar program description, goals, service provided.

Energy Division staff closely examined the 31 sister agency programs. If a good match for a PA program was found, the program would be retained on the potential duplication candidate list; otherwise, it would be removed.

For example, an Energy Division financing program expert closely examined possible overlap/duplication among relevant PA financing programs and CAEATFA programs and determined that there was no duplication.

Energy Division staff reduced the potential duplicate programs to three programs administered by the sister agency – the CEC, as shown in Table 3, "Final List of Possibly Duplicative Sister Agency Programs and Similar PA Programs".

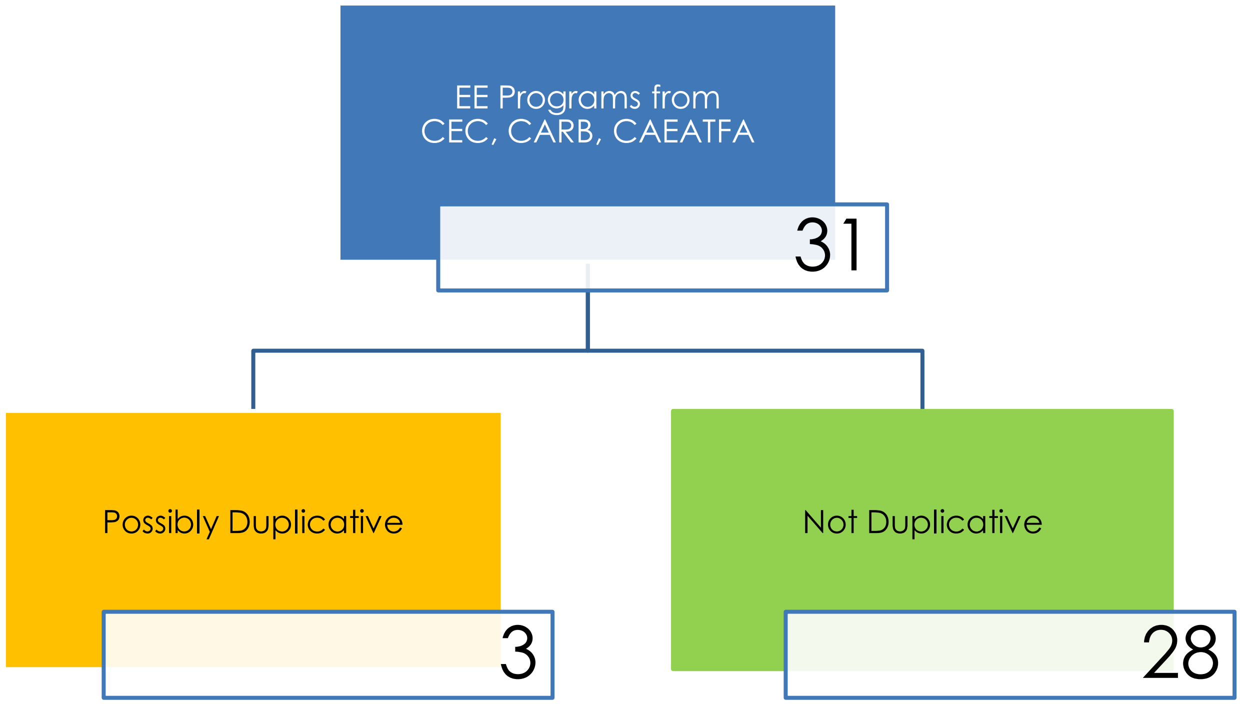
Table 3, Final List of Possibly Duplicative Sister Agency Programs and Similar PA Programs

Sister Agency	Sister Agency EE Program Name	Similar Program in CPUC	PA
CEC	Local Government Challenge	Local Government Energy Action Resources (LGEAR)	PGE
CEC	California Electric Homes Program - CalEHP	1) Savings by Design (SBD) 2) Statewide (SW) New Construction NonRes Com - All Electric	PGE PGE
CEC	Appliance Efficiency Program: Outreach and Education	Industrial (IND)-Energy Advisor	SCG

Energy Division staff realized that the term "overlap" is often associated with the term "duplication". However, "overlap" and "duplication" may have slightly different meanings in the context of energy efficiency programs. Therefore, Commission staff defined these terms for the analysis.

- **Overlap** can refer to situations where multiple programs or initiatives target similar energy-saving goals but serve different populations or geographic areas.
- **Duplication** refers to the presence of overlapping efforts that are completely redundant across multiple program indicators.

Figure 1, EE Program for Possible Duplication

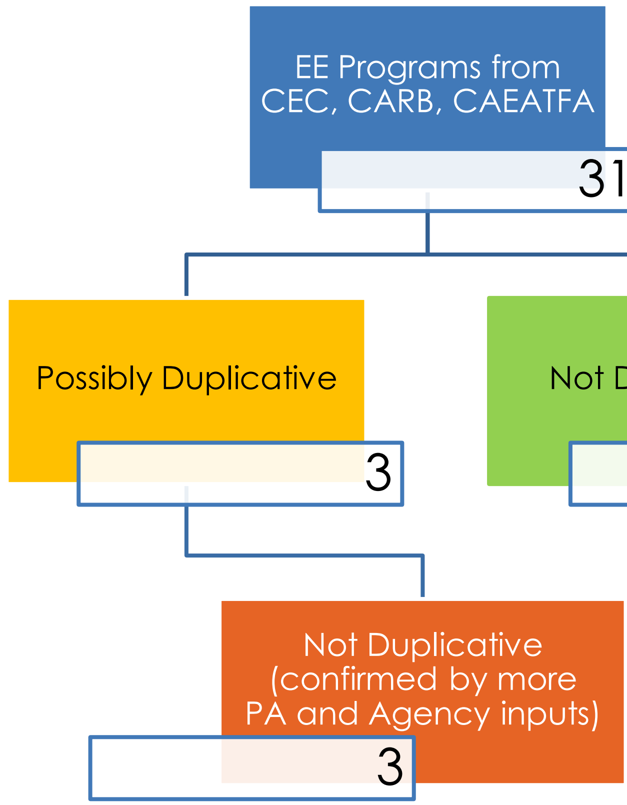


The second round of duplication selection involves both sister agency and the IOU program subject matter experts for an in-depth evaluation of the final three sister agency programs with overlap from all indicator perspectives and additional insights obtained from additional information.

- Energy Division staff reached out to the CEC, seeking their assistance in providing additional information based on the questionnaire outlined in Appendix 2 for the final phase of duplication analysis. The CEC team provided valuable information beyond the CEC website for the programs, including the last three candidates: "Local Government Challenge," "California Electric Homes Program – CalEHP," and "Appliance Efficiency Program: Outreach and Education", as shown in Figure 1.
- Energy Division staff also issued data requests to PG&E and SCG for their programs: "Local Government Energy Action Resources (LGEAR)," "Savings by Design (SBD)," "SW New Construction NonRes Com - All Electric," and "IND-Energy Advisor," respectively. Both PG&E and SCG responded with clarifications necessary to complete the final phase of duplication analysis.

As shown in Figure 2, all three programs were identified as Not Duplicative, but the programs have some overlap.

Figure 2, EE Program for Possible Duplication



Analysis and Findings

The research and analysis results have shown that no duplicative EE program has been identified between the PAs and the sister agencies for the 2023 program year. However, the study did find program overlaps existing at some point. For example, PG&E's Local Government Energy Action Resources (LGEAR) program and the CEC's Local Government Challenge grant program both target local governments, assisting them in achieving energy planning to improve energy performance. The PG&E program closed as of 2022, and the CEC program completed in March 2022, as confirmed by PG&E and the CEC respectively. If both programs were active simultaneously, PG&E's program could have led to duplication of the CEC program.

Another example of overlap could be PG&E's Statewide New Construction - All Electric program and the CEC's California Electric Homes Program. They share the same or similar goals and provide the same or similar services, except they target different customers: PG&E targets non-residential, while the CEC targets residential.

In conclusion, among the 31 sister agency programs in operation during 2023, three of them, constituting approximately 10%, feature one or more PA programs that overlap. None of these programs, amounting to 0%, exhibit duplication.

Recommendation

This report found there are no duplicative programs between the CPUC, CARB, CEC and CAEATFA during 2023; therefore, no further action is needed for the Commission.

The Energy Division staff will continue this process for the next report to the legislature to identify any future duplicative programs.

Appendix 1: Sister Agency Program List

	Sister Agency	Sister Agency EE Program Name	Similar Program in CPUC	PA	PrgID	Possible Overlap? (Y/N)	Duplicative? (Y/N)
1	CAEATFA	Sales and Use Tax Exclusion (STE) Program	On-Bill Financing Alternative Pathway	PGE	PGE210911	Y	N
2	CAEATFA	Property Assessed Clean Energy (PACE) Loss Reserve Program	Financing Programs	SCE	SCE-13-REN-001B	Y	N
3	CAEATFA	GoGreen Home Energy Financing	Water/Energy Nexus	NA	NA	N	N
4	CAEATFA	GoGreen Affordable Multifamily Energy Financing Program	Water/Energy Nexus	NA	NA	N	N
5	CAEATFA	GoGreen Business Energy Financing	On-Bill Financing Loan Pool SW-FIN-On-Bill Finance SW-FIN-New Finance Offerings	SCE SDGE SDGE	SCE-13-SW-007A1 SDGE3262 SDGE3264	Y	N
6	CAEATFA	Qualified Energy Conservation Bonds (QECB)	NA	NA	NA	N	N
7	CAEATFA	Private Activity Bonds for District Heating & Cooling	NA	NA	NA	N	N
8	CARB	Climate Heat Impact Response Program (CHIRP) - Currently On Hold Until Further Notice	NA	NA	NA	N	N

	Sister Agency	Sister Agency EE Program Name	Similar Program in CPUC	PA	PrgID	Possible Overlap? (Y/N)	Duplicative? (Y/N)
9	CARB	Distributed Generation Certification Program	NA	NA	NA	N	N
10	CARB	Electricity Transmission and Distribution Greenhouse Gas Emissions	NA	NA	NA	N	N
11	CARB	Emergency Backup Generators	NA	NA	NA	N	N
12	CARB	Public Safety Power Shutoff (PSPS) Events	NA	NA	NA	N	N
13	CARB	Stationary Fuel Cell Net Energy Metering	NA	NA	NA	N	N
14	CARB	U.S. EPA Clean Power Plan	NA	NA	NA	N	N
15	CARB	SB 1075 Report: Hydrogen Development, Deployment, and Use	NA	NA	NA	N	N
16	CEC	Local Government Challenge	Local Government Energy Action Resources (LGEAR)	PGE	PGE2110051	Y	N
17	CEC	California Electric Homes Program - CalEHP	Savings by Design (SBD) SW New Construction NonRes Com - All Electric	PGE PGE	PGE211025; PGE_SW_NC_NonRes_Com_electric	Y	N
18	CEC	Appliance Efficiency Program: Outreach and Education	IND-Energy Advisor	SCG	SCG3713	Y	N
19	CEC	Inflation Reduction Act Residential Energy Rebate Programs in California	Energy Savings Performance Incentive	SCE	SCE-13-ESPI	Y	N

	Sister Agency	Sister Agency EE Program Name	Similar Program in CPUC	PA	PrgID	Possible Overlap? (Y/N)	Duplicative? (Y/N)
20	CEC	Equitable Building Decarbonization Program	Targeted Decarbonization Services, C&S Decarbonization Support Placeholder	PGE	PGE_CS_PortfolioSupport	Y	N
21	CEC	Building Initiative for Low-Emissions Development Program	Technology and Equipment for Clean Heating (TECH), to be administered by Southern California Edison	SCE	NA	N	N
22	CEC	Energy Partnership Program	NA	NA	NA	N	N
23	CEC	Energy Efficiency in Existing Buildings	NA	NA	NA	N	N
24	CEC	Bright Schools Programs	NA	NA	NA	N	N
25	CEC	California Clean Energy Jobs Act K-12 Program - Prop 39	NA	NA	NA	N	N
26	CEC	Energy Innovation Ecosystem	Emerging Technologies Program, Electric Emerging Technologies Program, Electric - SCE Costs SW Emerging Technologies - Electric SW Emerging Technologies - Electric (Utility)	SCE SCE SDGE SDGE	SCE_SW_ETP_Elec SCE_SW_ETP_Elec_PA SDGE_SW_ETP_Elec SDGE_SW_ETP_Elec_PA	Y	N
27	CEC	Gas Research and Development Program	ET-Technology Development Support ET-Technology Assessment Support ET-Technology Introduction Support	SCG	SCG3721 SCG3722 SCG3723 SCG_SW_ETP_Gas_PA	Y	N

	Sister Agency	Sister Agency EE Program Name	Similar Program in CPUC	PA	PrgID	Possible Overlap? (Y/N)	Duplicative? (Y/N)
			ET-SW-Emerging Technologies, Gas-PA				
28	CEC	Building Energy Benchmarking Program	NA	NA	NA	N	N
29	CEC	Building Energy Efficiency Standards - Title 24	NA	NA	NA	N	N
30	CEC	Enforcement Case Settlements	NA	NA	NA	N	N
31	CEC	Home Energy Rating System Program - HERS	NA	NA	NA	N	N

Appendix 2: Questions for the CEC

1.	Could you please confirm the information listed in the attachment regarding the CEC programs? This information may include the program name, program description, program goals, services provided, target customers, program sector, program category, program status, and so on.
2.	Is the program targeted at the IOU service territory, POU territory, or the entire state?
3.	What is the program's duration/timeline?
4.	Who is the program implementer?
5.	What are the major energy efficiency measures installed?
6.	What does the program financially provide to the target customer/audience (grants, technical assistance, financial incentives, rebates, etc.)
7.	What are the relevant building types in the program?
8.	What other important information could be helpful for CPUC staff's analysis of duplicative EE programs?