2023 CALIFORNIA ELECTRIC AND GAS UTILITY COSTS REPORT

AB 67 Annual Report to the Governor and Legislature

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California Public Utilities Commission

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Table of Contents

List of Figures

List of Tables

Executive Summary

The California Public Utilities Commission (CPUC) issues the Assembly Bill (AB) 67 Annual Report (referred to as the 2023 California Electric and Gas Utility Costs Report) pursuant to California Public Utilities 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 2023 California Electric and Gas Utility Costs Report, published in 2024, provides a detailed narrative and transparency into factors driving electric and gas rates for 2023 activities.

Key highlights include:

- **Electric rates**: Pacific Gas & Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) saw their costs go up compared to last year, mainly because of higher costs for generating and delivering electricity. The CPUC has also been successful in negotiating lower transmission costs, saving Californian customers billions of dollars over the years.

- **Greenhouse Gas Cap-and-Trade Program**: Utilities paid around $299 million for emissions, but they also got credits from selling carbon allowances, which helped lower costs for customers.

- **Demand Side Management programs[2] and regulatory fees:** These programs and fees together make up more than 13% of what customers pay for electricity, showing the ongoing investment in saving energy and the payment of charges imposed by various levels of government.

- **Gas rates**: The total cost of natural gas went up by about 11.2% in 2023, mainly because of higher gas prices, extreme weather, and production challenges.

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[1] 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] Demand Side Management programs include programs such as Energy Efficiency, Energy Savings Assistance, California Alternative Rates for Energy (administrative costs only), Self Generation Incentive Program, Demand Response, and the Electric Program Investment Charge.

I. Introduction

Enacted pursuant to AB 67 (Levine, Chapter 562, Statutes of 2005), California Public Utilities 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 by April 1st of 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 2023 California Electric and Gas Utility Costs Report is submitted by the CPUC to fulfill these statutory requirements.

Background

This report provides a detailed narrative of various energy policies 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 since 2013. This report focuses on costs from 2023 only.

The report presents an analysis of 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). Using sales forecasts, rates are set to collect these authorized revenue requirements. For certain utility programs, discrepancies between authorized revenue requirements and actual revenues and expenses are captured through balancing account mechanisms, which true-up the actual revenue to the authorized revenue requirement in the following year. This mitigates the risk of the utilities collecting more than or less than their authorized revenue requirements, particularly if sales are lower than forecast due to conservation, behind-the-meter solar, efficiency programs, or other reasons.

Overview

Drivers Behind Electric Utility Cost Changes

- **Compared to 2022, the 2023 CPUC-authorized annual revenue requirements[3] for PG&E, SCE, and SDG&E increased by 19.2 percent, 16.6 percent, and 0.5 percent, respectively.** The 2023 revenue requirements for the three electric utilities are shown in **Table 1.1**. The total company revenue requirement (including transmission)[4] for the electric utilities in 2023 is as follows: PG&E $17.8 billion, SCE $17.5 billion, and SDG&E $4.4 billion for a total of $39.7 billion.

Table 1.1: Electric Utility Revenue Requirement Comparison ($000)[5]

Utility	2023 CPUC	2022 CPUC	Difference ($000)	Difference %	2023 Transmission	2023 Total Company
PG&E	14,487,493	12,156,984	2,330,510	19.2	3,272,496	17,759,989
SCE	16,177,659	13,880,415	2,297,244	16.6	1,354,762	17,532,420
SDG&E	3,515,287	3,498,824	16,463	0.5	860,184	4,375,471
Total	**34,180,439**	**29,536,222**	**4,644,217**	**15.7**	**5,487,441**	**39,667,880**

SDG&E's revenue requirement essentially remained flat because year-over-year increases and decreases in different categories offset each other; for example, a decrease in generation costs offset the addition of costs for various distribution-related programs. Most of the increase in SCE's revenue requirement is due to increases in energy procurement costs. Much of PG&E's increase is due to new costs related to wildfire mitigation.

- **Power procurement costs increased significantly for SCE, increased slightly for PG&E, and decreased slightly for SDG&E during 2023.** 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 2023 revenue requirement for the three electric utilities associated with generating and procuring electricity.

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[3] 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.

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

[5] PG&E Advice Letter 7009-E, SCE Advice Letter 5109-E, and SDG&E Advice Letter 4129-E, effective 9/01/2023, 10/01/2023, and 1/01/2023, respectively.

Table 1.2: Electric Generation Revenue Requirement Comparison ($000)

Utility	2023	2022	Difference	
			$000	%
PG&E	4,941,037	4,670,136	270,901	5.8
SCE	7,580,809	5,124,938	2,455,871	47.9
SDG&E	1,091,201	1,138,195	(46,994)	(4.1)
Total	**13,613,047**	**10,933,269**	**2,679,778**	**24.5**

The significant increase in SCE's generation revenue requirement is primarily due to large increases in fuel and purchased power costs in 2023. In particular, SCE's load procurement costs increased significantly due to power prices that rose by 45% and due to slightly higher load. To a lesser extent, collections for SCE's 2023 Energy Resource Recovery Account (ERRA) Trigger Mechanism also contributed to the increase.[6] PG&E's slight increase was mostly due to changes in the classification of generation costs;[7] aside from these classification changes, increases in certain generation cost categories were offset by decreases in other generation cost categories. SDG&E's slight decrease was mostly due to the decrease in ERRA Trigger collections; aside from this, increases in certain generation cost categories were offset by decreases in other generation cost categories.

There is also a growing percentage of the IOUs' load moving to service from Customer Choice Aggregators (CCAs), reducing the total load for which the IOUs must procure. For example, in 2022, 31 percent of total IOU system load was served by CCAs. However, due to high fixed costs and high prices per megawatt hour, generation rates rose on a per customer basis.

For additional analysis, see Chapter IV.

- **Electric distribution costs increased for PG&E and SDG&E and decreased for SCE.** Distribution costs include the costs of providing service below a certain voltage (60 kilovolt (kV), 200 kV, and 69 kV for PG&E, SCE, and SDG&E, respectively) that are regulated by the CPUC. **Table 1.3** shows the 2023 revenue requirement for the three electric utilities associated with distribution of energy through the electric grid.

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[6] The ERRA Balancing Account records the investor-owned utilities' fuel and purchased power revenues against actual recorded costs. A utility is required to file an expedited application to adjust rates when its ERRA BA balance exceeds, and is expected to continue to exceed, specified thresholds (the Trigger Mechanism). The Trigger Mechanism is meant to promote the timely recovery of a utility's procurement cost undercollections or facilitate reimbursement to ratepayers for overcollections. It is discussed later in this report.

[7] Changes in the way PG&E classified generation costs resulted in both the exclusion of items previously included the category and the inclusion of items previously included in other categories. Amounts for the cost items moved into generation in 2023 did not change year over year. Amounts for items moved out of generation in 2023 were mostly related to DWR power charge refunds, which went to zero in 2023.

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

Utility	2023	2022	Difference	
			$000	%
PG&E	8,148,501	6,928,792	1,219,709	17.6
SCE	7,251,843	8,225,321	(973,478)	(11.8)
SDG&E	1,923,385	1,624,992	298,393	18.4
Total	**17,323,729**	**16,779,105**	**544,624**	**3.2**

PG&E's increase can be attributed primarily to the addition of costs related to Wildfire Mitigation and Catastrophic Events applications. The increase represents costs approved for recovery in 2023 but that were incurred in previous years (2020 through 2022) and therefore were not yet included in the 2022 revenue requirement.

While most of SDG&E's increase is due to changes in the classification of 2023 distribution cost items,[8] a significant portion can also be attributed to the addition of costs for tree trimming, an electric vehicle charging station program, and the replacement of SDG&E's customer information system. The decrease in SCE's distribution costs is largely due to changes in cost classification;[9] these changes more than offset a small increase of roughly $500 million related to a new billing and customer service system and the recovery of wildfire insurance premiums. For additional analysis, see Chapter III.

- **Compared to 2022, the total electric transmission costs passed onto ratepayers moderately increased for PG&E, SCE, and SDG&E.** Transmission rates include the costs of providing service 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 2023 electric transmission costs compared to 2022 for the three investor-owned utilities.

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[8] A number of SDG&E cost items that were included in the Public Purpose Programs category in previous AB 67 reports are now classified as distribution costs. In comparison to their 2022 values, these reclassified costs decreased by 43% in 2023.

[9] Changes in the way SCE classified distribution costs resulted in both the exclusion of items previously included the category and the inclusion of items previously included in other categories. As a whole, costs that were moved into and out of the distribution category decreased from their 2022 levels or increased refunds to ratepayers.

Table 1.4: Electric Transmission Cost Comparison ($000)

Utility	2023	2022	Difference	
			$000	%
PG&E	3,272,496	2,948,943	323,552	11.0
SCE	1,354,762	1,390,045	(35,283)	(2.5)
SDG&E	860,184	772,822	87,362	11.3
Total	**5,487,441**	**5,111,810**	**375,632**	**7.3**

PG&E's 11 percent increase in transmission costs in 2023 maintains the historic upward trend of transmission costs. The revenue requirement in PG&E's transmission owner rate case at FERC increased by $109 million in 2023.[10] PG&E attributes this increase primarily to Operations and Maintenance (O&M) and Administrative & General (A&G) expenses, and specifically identifies wildfire prevention, mitigation, and repair, as well as other upgrades for grid operations such as work at the request of others (WRO) as significant cost drivers. The increase in WRO costs is a result of delays in projects that were previously forecasted to be operational before 2022 and new network upgrade project requests. In 2023, the Transmission Access Charge Balancing Account Adjustment included $492 million in costs related to under-collection at the CAISO for others' use of the PG&E transmission grid. SCE's increase in retail base transmission revenue requirement relates to a large upward cost adjustment to its 2017/2018 wildfires/mudslides reserve accrual and a year-over-year increase in depreciation expenses offset by decreases in O&M and A&G expenses [11]. However, a large credit in the Transmission Revenue Balancing Account Adjustment (TRBAA) more than offset the cost increases, resulting in an overall reduction in SCE's transmission costs. SDG&E's increase is related to higher O&M costs, depreciation expenses, property and payroll taxes, a six percent increase in the transmission rate base[12], and increase in the true-up adjustments and franchise fees and uncollectibles between rate year 2022 and rate year 2023. For additional analysis, see Chapter III.

- **Public Purpose Program costs increased for PG&E and SCE and decreased for SDG&E during 2023.** These Public Purpose Programs (PPPs) include Energy Efficiency, Energy Savings Assistance, and California Alternative Rates for Energy (CARE) among other programs like the Schools Energy Efficiency Program (SEEP), created pursuant to AB 841. Most of the apparent increase in PG&E's PPP costs from 2022-2023 is

[10] It is worth noting that as a result of the settlement in PG&E's TO20 transmission owner formula rate case in 2020, costs to PG&E's ratepayers, while high, are hundreds of millions of dollars less than they otherwise would have been if PG&E's as-filed formula were in effect.

[11] The SCE rate case is an annual update filing as required by the FERC settlement in SCE TO2019A, FERC Docket ER19-1553.

[12] SDG&E's TO5 Cycle 5 Formula Rate Filing, TO5-Cycle 5, Transmittal Letter, December 1, 2022.

attributable to changes in the way PG&E classified costs for 2023.[13] PG&E PPP cost categories that remained constant saw an increase of 14%, mostly due to costs associated with Energy Efficiency and the Electric Program Investment Charge (EPIC). SDG&E saw CARE administrative expenses more than double while Energy Efficiency costs increased by over 200%, as did Low-Income Energy Efficiency costs; however, SDG&E's PPP increases were more than offset by the effects of the reclassification as distribution costs of some PPP costs, as mentioned earlier. SCE's increase was primarily due to higher authorized funding for Energy Efficiency and the Energy Efficiency Market Access Program, offset by a return of the year-end 2022 overcollection in the CARE Balancing Account. **Table 1.5** shows the 2022 and 2023 revenue requirement for the three electric utilities associated with PPPs.

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

Utility	2023	2022	Difference	
			$000	%
PG&E	878,915	389,022	489,894	125.9
SCE	728,767	646,982	81,785	12.6
SDG&E	499,337	681,337	(182,000)	(26.7)
Total	**2,107,020**	**1,717,341**	**389,678**	**22.7**

- **Bonds and Regulatory Fees (including nuclear decommissioning revenue requirements) increased for PG&E, SCE, and SDG&E during 2023.** 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 have been substantively replaced by charges to support the AB 1054 Wildfire Fund. Fees include a variety of charges levied by federal, state, and local governments. Fees are included as specific components of other revenue requirements, except for nuclear decommissioning costs, which are recovered by the Nuclear Decommissioning Adjustment Mechanism (NDAM). **Table 1.6** shows the 2023 revenue requirements for the three electric utilities associated with bonds and nuclear decommissioning activities.

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[13] For 2023, a number of PG&E cost items previously classified as PPP were moved to the Distribution category. Because these moved costs summed to a refund to ratepayers in 2022, moving them out of the PPP category in 2023 resulted in a large year-over-year increase for the PPP category. In actuality, the moved costs decreased revenue requirement in 2023 by an additional 10% in comparison to their 2022 values.

Table 1.6: Bonds and Fees Revenue Requirement Comparison ($000)

Utility	2023	2022	Difference	
			$000	%
PG&E	1,144,768	574,144	570,624	99.4
SCE	509,995	410,758	99,237	24.2
SDG&E	78,272	54,300	23,972	44.1
Total	**1,733,035**	**1,039,201**	**693,834**	**66.8**

During 2023, much of the variation in the revenue requirements for bonds and assorted fees was due to the conclusion of refunds from old Energy Recovery Bonds and DWR bonds after 2022. The refunds had been off-setting costs for ratepayers in prior years. For additional analysis, see Chapter VI.

- **The revenue requirements for PG&E, SCE, and SDG&E increased in 2023 due to adjustments for amortizations of balances in balancing and/or memorandum accounts. Table 1.7** shows the effects of these adjustments on the revenue requirements for the electric utilities.

Table 1.7: Adjustments to the 2023 Revenue Requirement ($000)

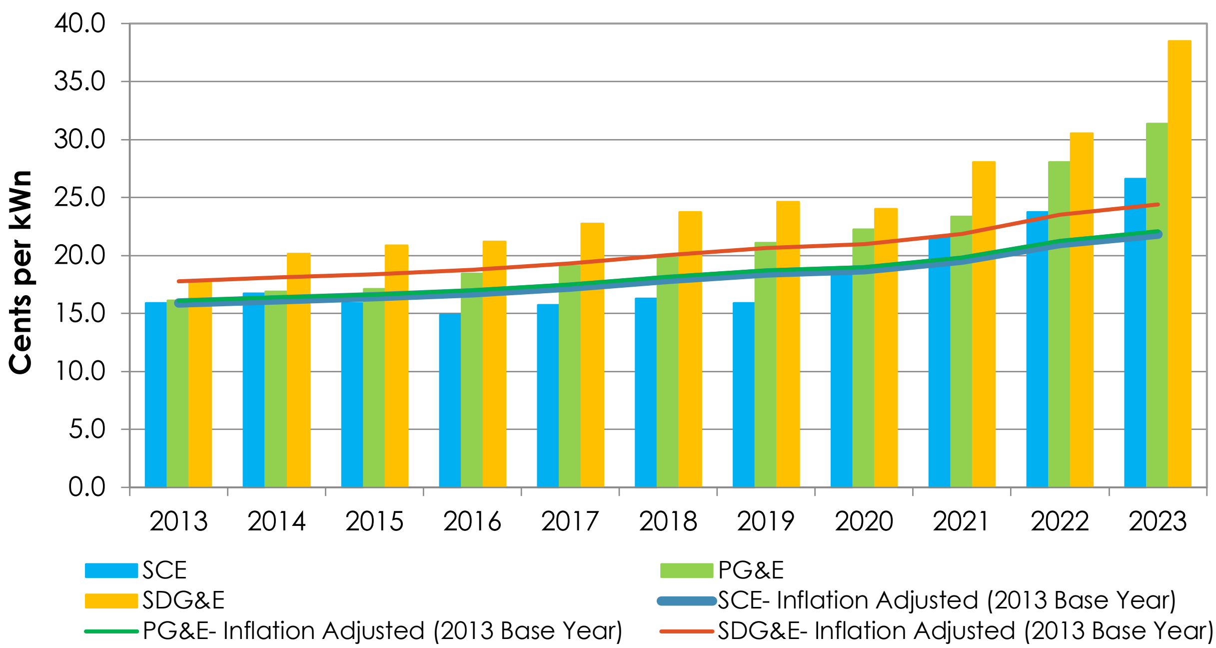
Utility	Forecasted 2023 Costs	Amortization Adjustments	Authorized 2023 Revenue Requirement	Difference %
PG&E	13,029,398	1,458,095	14,487,493	11.2%
SCE	15,022,006	1,155,652	16,177,659	7.7%
SDG&E	3,207,447	307,840	3,515,287	9.6%
Total	**31,258,852**	**2,921,587**	**34,180,439**	**9.3%**

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.

Electric Utility Rate Trends Over Time

- Increases in Bundled System Average Rates generally have been above inflation since 2019. **(Figure 1.1).** From 2019 to 2023, bundled system average rates across the three electric IOUs have increased at an annual average of approximately 12.5 percent (**Table 1.8**), which is above the average annual inflation rate of 4.02 percent over the same time period. In 2023, SCE's bundled system average rate was 26.6 cents per kilowatt hour (¢/kWh), PG&E's was 31.3 ¢/kWh, and SDG&E's was 38.5 ¢/kWh.[14]

Figure 1.1: Trends in Electric Bundled System Average Rates (2013-2023)[15]



Annual Inflation Rate Change (2014-2023)[16]										
2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Average (2019-2023)
1.83%	1.46%	2.28%	2.94%	3.7%	2.97%	1.67%	4.25%	7.36%	3.9%	**4.02%**

[14] PG&E Advice Letter 7009-E, SCE Advice Letter 5109-E , and SDG&E Advice Letter 4129-E, effective 9/01/2023 , 10/01/2023 , and 1/01/2023 , respectively.

[15] Total System Average Rates reflect total authorized revenue requirement and total forecasted sales for both bundled and unbundled customers.

[16] Source: California Department of Finance, November 2023 CPI.

Table 1.8: Annual Change in Electric Bundled System Average Rates (2019-2023)

Utility	2019	2020		2021		2022		2023		Average
	Rate	Rate	% Change	Rate	% Change	Rate	% Change	Rate	% Change	% Change
SCE	15.9	18.5	16.4%	21.6	16.8%	23.7	9.7%	26.6	12.2%	13.8%
PG&E	21.1	22.2	5.2%	23.4	5.4%	28.0	19.6%	31.3	11.8%	10.5%
SDG&E	24.46	24.0	(1.9)	28.1	16.7	30.5	8.9%	38.5	26.2%	12.5%

- **For SDG&E, bundled system average rates have generally trended above inflation since 2013.** From 2013 to 2020, SCE bundled system rates tracked inflation but PG&E and SDG&E rates did not. Starting in 2021, none of the large electric IOU rates tracked inflation.[17]

- **Electric generation and distribution are the largest components of electric rates.** As shown in **Figure 1.2** and **Table 1.9**, utility-owned generation and purchased power sources, plus distribution, collectively account for approximately 75 percent of the utilities' electric rates.

[17] All three utilities have experienced declines in bundled kWh sales, 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).

Figure 1.2: 2023 System Average Electric Rate Components

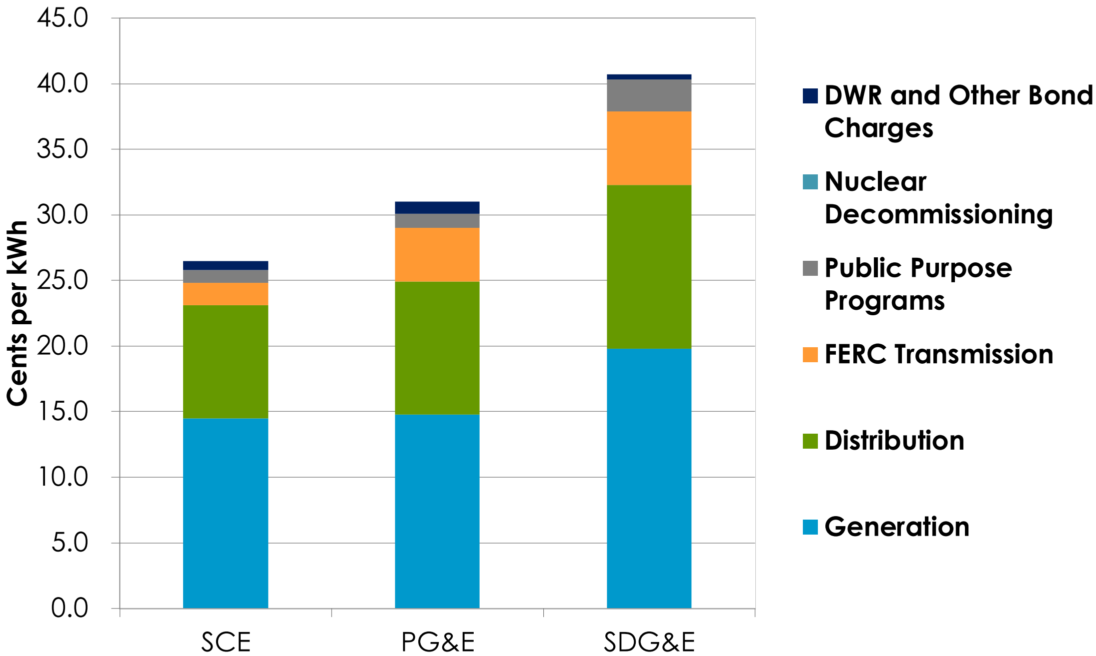


Table 1.9: 2023 System Average Electric Rate Component Values (¢/kWh)

Rate Component	SCE	PG&E	SDG&E[18]
Generation	14.5	14.8	19.8
Distribution	8.6	10.1	12.5
FERC Transmission	1.7	4.1	5.6
Public Purpose Program	1.0	1.1	2.4
Nuclear Decommissioning	0.0	0.1	0.0
DWR and Other Bond Charges	0.7	0.9	0.4
Total	**26.6**	**31.1**	**40.7**

[18] SDG&E's rate is an estimated bundled residential average rate.

Drivers Behind Gas Utility Cost Changes

- **In 2023, total natural gas revenue requirement increased by 11.2 percent from 2022, a lower increase than the 18.6 percent increase seen from 2021 to 2022.** The 2023 gas utility revenue requirement was primarily driven by high procurement costs in early 2023. However, the rate of increase declined as commodity prices fell after the 2022-2023 winter season. In addition, there were smaller increases in transportation and Public Purpose Program (PPP) costs that contributed to the revenue requirement.

The remainder of this report provides a breakdown of the various 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.

II. Determining Revenue Requirements

Due to the increasingly varied nature of utility costs and the multitude of energy policy programs, the determination of the funds needed for utility service and the rate-setting process at the CPUC have grown more complex over time. The following venues are used to determine the revenues that the utilities are authorized to collect through rates:

1. **General Rate Cases (GRCs):** GRCs for the large energy utilities occurred on a four-year cycle based on Decision (D.) 20-01-002. In GRCs, the CPUC evaluates the regulated operations of the utilities and determines the reasonableness of utility requests for changes in revenue needed to fund utility service. 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.

2. **Transmission rate cases at the Federal Energy Regulatory Commission (FERC):** The CPUC is required to allow recovery of all FERC-authorized costs. Because transmission rates are subject to oversight by FERC, the transmission revenue requirements of the various utilities that participate in the CAISO are determined in FERC proceedings, called Transmission Owner (TO) rate cases.

3. **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 without any profit or mark-up for the utility. Some public purpose charges are also authorized here.

4. **Program Budget allocations**: Specific program area proceedings in which program budgets are determined.

The utilities earn a rate of return (authorized profit from rate base) on utility-owned capitalized assets and equipment. For many cost categories, 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. For instance, some customers do not receive full service (also known as "bundled service") from the utility and may generate their own electricity on site or buy electricity from a non-utility source (e.g., an Electric Service Provider (ESP), or a Community Choice Aggregator (CCA)). Customers who receive electricity from a CCA or ESP only pay a portion of the generation costs for resources procured by IOUs for all customers in their service territories, when directed to do so by the CPUC, but they do pay transmission and distribution costs.[19] These customers are also 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** offers a breakdown of the major components of the electric IOUs' 2023 revenue requirements.

Table 2.1: 2023 Electric IOU Authorized Revenue Requirement Components ($000)

Revenue Component	SCE	PG&E	SDG&E
Generation / Energy Procurement	6,763,014	4,207,213	948,361
Purchased Power	5,439,522	1,905,283	734,656
Utility Owned Generation Fuel	569,335	724,881	260,883
General Rate Case	721,432	2,068,041	120,142
Other Regulatory	32,725	(490,991)	(167,320)
Distribution	7,359,386	6,671,844	1,674,791
Transmission	1,354,762	3,272,496	860,184
Public Purpose Programs	1,407,438	2,021,657	631,100
Bonds and Fees	509,995	1,144,768	78,272

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.

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 2013 and 2023, the utilities' rate bases increased in size from $46.3 billion to $88.7 billion, or a 91 percent increase in

[19] 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.

nominal dollars over the past decade, triggering corresponding increases in GRC revenue requirements.[20]

Figure 2.1: Trends in Electric Utility Rate Base

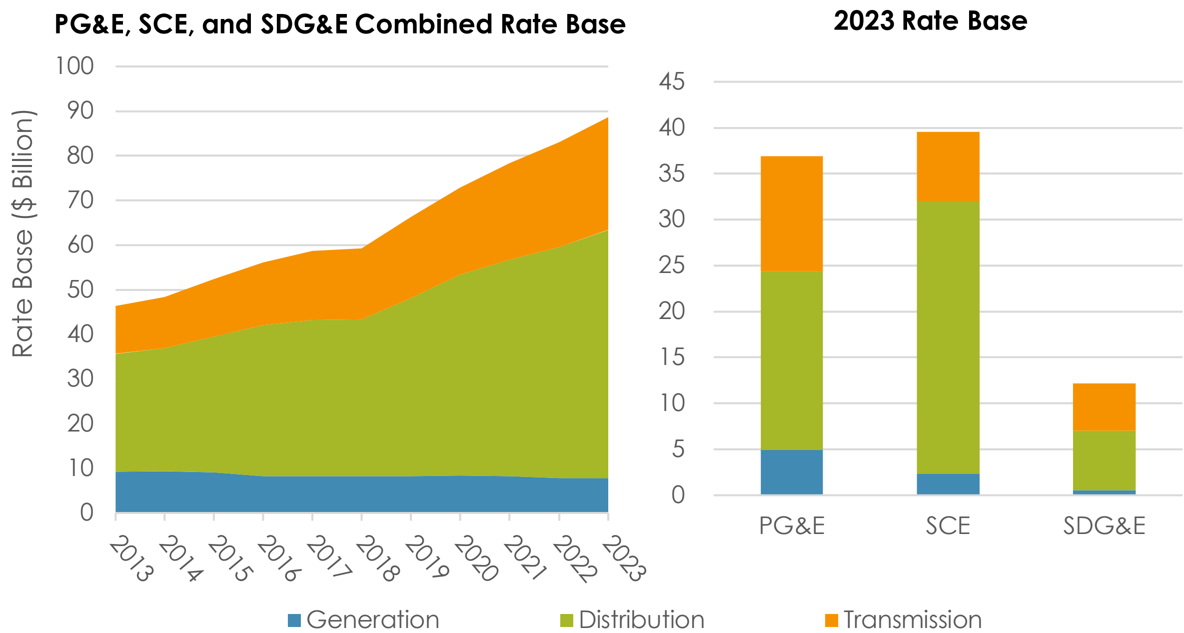


Table 2.2 shows the contributions of generation, transmission, and distribution components to the 2023 rate base.

Table 2.2: 2023 Utility Rate Base Components ($000)

Category	PG&E	SCE	SDG&E	Total
Generation	4,913,190	2,332,817	535,070	**7,781,076**
Distribution	19,419,668	29,687,778	6,467,555	**55,575,000**
Transmission	12,585,479	7,552,469	5,159,756	**25,297,704**
Total	**36,918,337**	**39,573,063**	**12,162,380**	**88,653,780**

[20] When adjusted for inflation, the 2013 rate base equals $60.2 billion. Therefore, an inflation-adjusted comparison of rate base from 2013 to 2023 indicates the rate base increased in size from $60.2 billion (adjusted for inflation from $46.3 billion) to $88.7 billion, or 47 percent.

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.[21] 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 62 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 38 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.

[21] 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 Decision 20-01-002, January 22, 2020, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M325/K471/325471063.PDF.

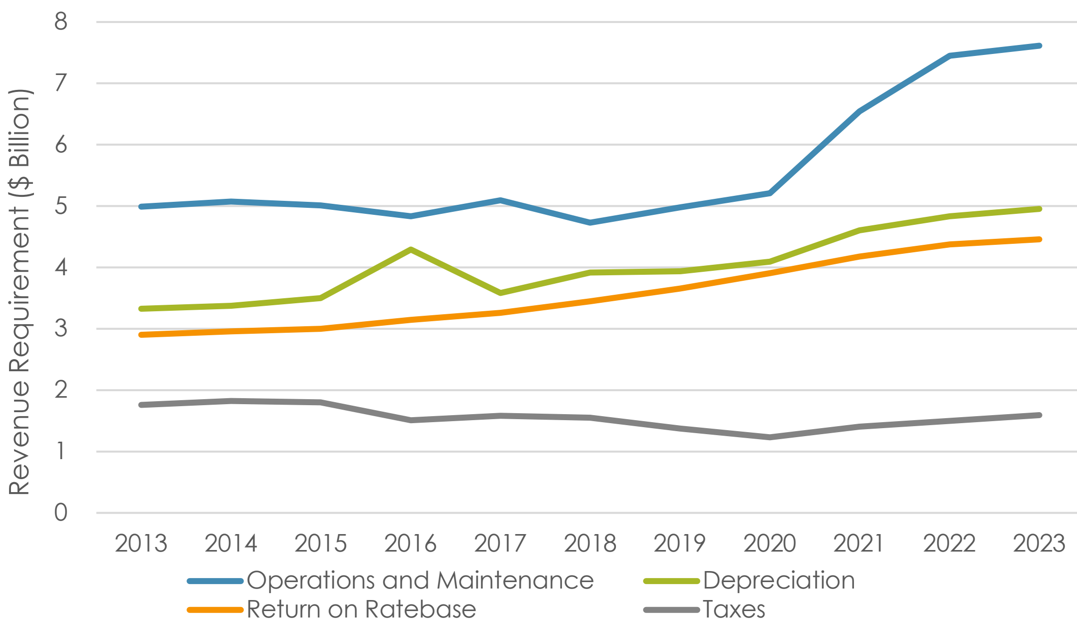
Table 3.1: 2023 General Rate Case Revenue Requirements ($000)[22]

	PG&E	SCE	SDG&E
Operation and Maintenance	4,044,811	2,736,330	832,693
Depreciation	2,400,960	2,132,791	420,323
Return on Rate Base	1,722,508	2,380,516	355,390
Taxes	571,605	831,180	186,527
Total	**8,739,885**	**8,080,818**	**1,794,932**

(Excludes FERC-determined transmission revenue requirements)

Figure 3.1 below shows a ten-year trend of 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[23]



- **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.

[22] Amounts shown include revenues adopted by the CPUC in the utilities' GRCs.

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

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. 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 determined in each utility's GRC, the CPUC now determines the ROR 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 2013, the total distribution revenue requirement has increased, from $9.3 billion to $15.7 billion (**Figure 3.2**).[24] Over the same time period, depreciation expenses have experienced an approximate 2.1 percent average annual growth rate.[25] 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 2023 also includes recovery of catastrophic event expenses.

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[24] When adjusted for inflation, the 2013 total distribution revenue requirement equals $12.1 billion, which indicates distribution revenue requirement has increased approximately 30 percent from 2013 to 2023 (in 2023 dollars).

[25] Adjusted for inflation.

Figure 3.2: Trends in Distribution Revenue Requirement

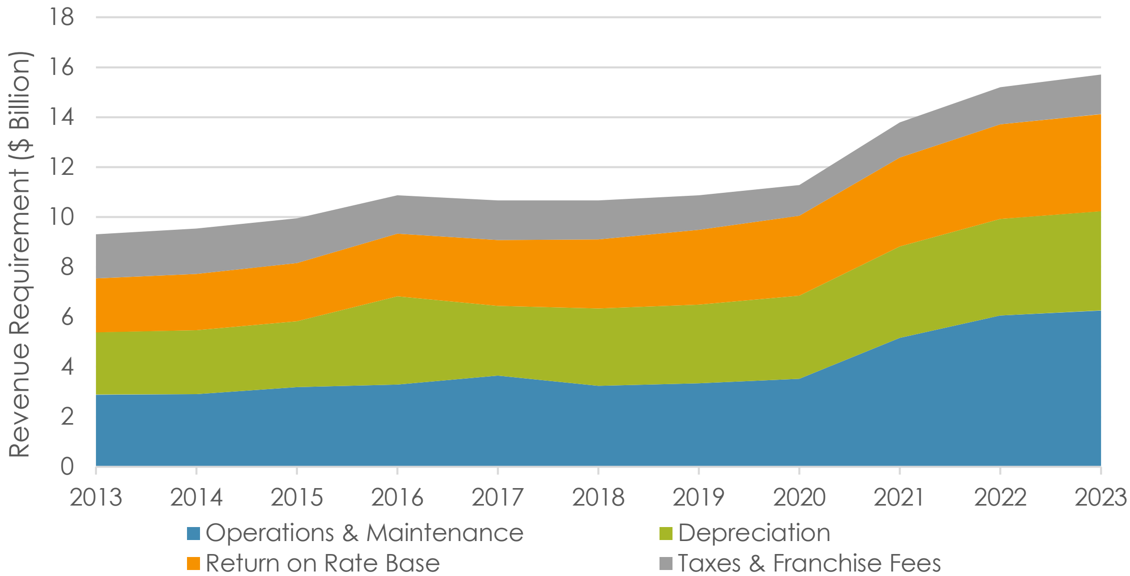


Table 3.2 below shows the contributions of distribution components to the 2023 revenue requirement.

Table 3.2: 2023 Distribution Revenue Requirements ($000)[26]

	PG&E	SCE	SDG&E
Operations and Maintenance	3,047,334	2,400,046	808,206
Depreciation	1,691,406	1,920,119	370,121
Return on Rate Base	1,361,499	2,208,041	309,936
Taxes and Franchise Fees	571,605	831,180	186,527
Total	**6,671,844**	**7,359,386**	**1,674,791**

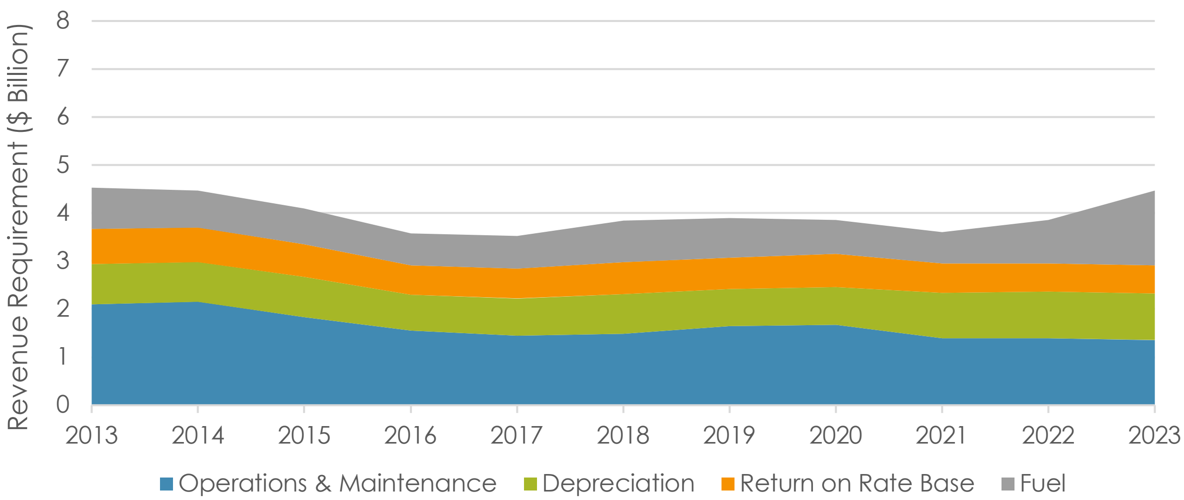
Utility Owned Generation Revenue Requirements

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

[26] Amounts shown include revenues adopted by the CPUC in the utilities' GRCs.

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. In 2023, fuel costs were higher due to the combination of rising natural gas prices and market purchases which drove an increase in the generation revenue requirement.

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 fossil-fueled generation, UOG now accounts for only 7 percent of their combined revenue requirements. The 2023 generation revenue requirement for the electric IOUs is shown in **Table 3.3**.

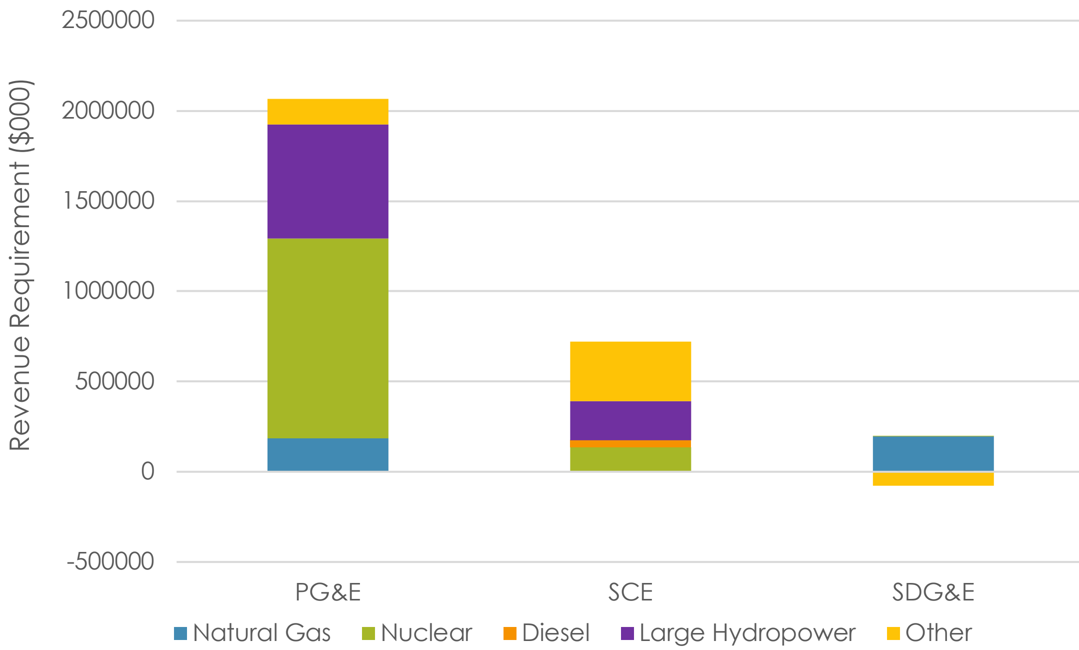
Table 3.3: 2023 Generation Revenue Requirements ($000)[27]

	PG&E	SCE	SDG&E
Operations and Maintenance	997,478	336,285	24,487
Depreciation	709,554	212,673	50,201
Return on Rate Base	361,009	172,475	45,454
Total	**2,068,041**	**721,432**	**120,142**

[27] Amounts shown include revenues adopted by the CPUC in the utilities' GRCs.

Figure 3.4 and **Table 3.4** show the components of 2023 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). In addition, PG&E's hydroelectric system has 67 powerhouses and produces roughly 3,900 megawatts (MW) of power.[28] 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.[29] 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.[30]

Figure 3.4: Generation Revenue Requirements by UOG Source



*Other includes fuel cells and renewables

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[26] Pacific Gas & Electric Company - PG&E. Hydroelectric System. pge.com. https://www.pge.com/en/about/pge-systems/hydroelectric-system.html

[29] 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.

[30] Desert Star Energy Center was purchased from Sempra Natural Gas in October 2011 and Cuyamaca Peak Energy Plant was purchased in January 2012.

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

	PG&E	SCE	SDG&E
Natural Gas	186,401	0	195,070
Diesel	0	38,759	0
Nuclear	1,104,915	136,183	1,522
Other	143,171	330,038	(76,451)
Large Hydropower	633,553	216,152	0
Total	**2,068,041**	**721,432**	**120,142**

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).[31] 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 power to alleviate the capacity shortfall. 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) and approved ratepayer funding of $241.2 million for employee retention and retraining ($222.6 million) and license renewal activities ($18.6 million). In September 2018, SB 1090 authorized an additional $225.8 million in funding for the shutdown of Diablo Canyon Nuclear Power Plant, with $140.8 million of that amount for employee retention programs and $85 million for a Community Impact Mitigation Program (see also D.18-11-024). In total, $467 million in ratepayer funding was approved. On September 2, 2022, SB 846 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 CPUC proceeding to assess and forecast costs for Diablo Canyon

[31] 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.

during its extension period.[32] On December 14, 2023, the CPUC approved D.23-12-036 authorizing a contingent five-year extension of Diablo Canyon operations and creating a Diablo Canyon Extended Operations Forecast proceeding which will be filed every March starting March 29, 2024. As approved in PG&E's most recent General Rate Case (D.23-11-069), Diablo Canyon's forecast 2023 Operating Costs (i.e., O&M) were $314 million while its forecast 2023 capital expenditures were $11 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 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 2023 operating costs (O&M) was approximately $76 million while its share of 2023 capital expenditures totaled approximately $36 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 Commission 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. In December 2021, the CPUC approved the 2018 NDCTP for SONGS, D.21-12-026, in which SCE and SDG&E requested no rate changes. The one ongoing NDCTP proceeding, A.22-02-016 for SCE and SDG&E, has not requested 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:[33]

- 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 (see

[32] 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.

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

D.23-09-004 and D.21-12-026).

- 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.

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 2013 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 2013.

Figure 3.5: Trends in Weighted Average Rate of Return (ROR)

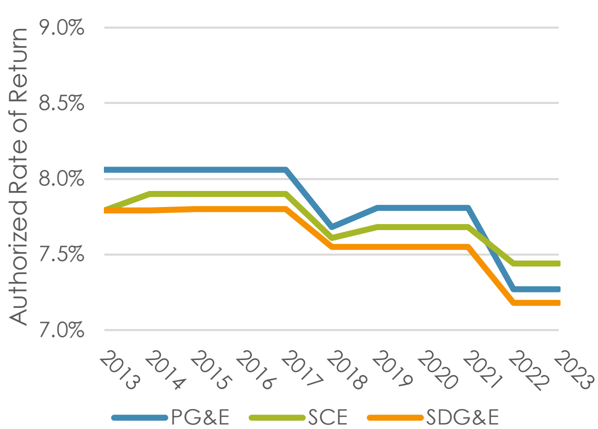


Figure 3.6: Trends in Return on Equity (ROE)

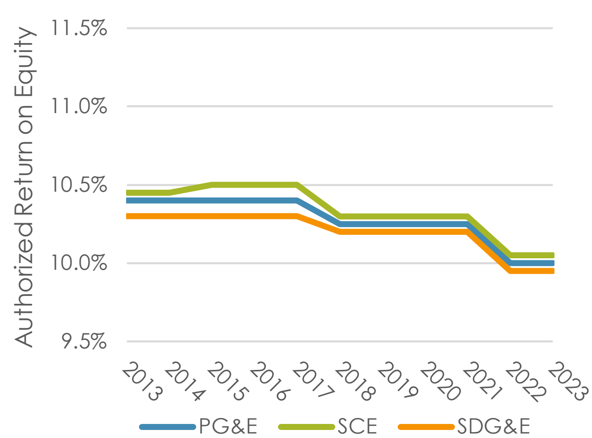
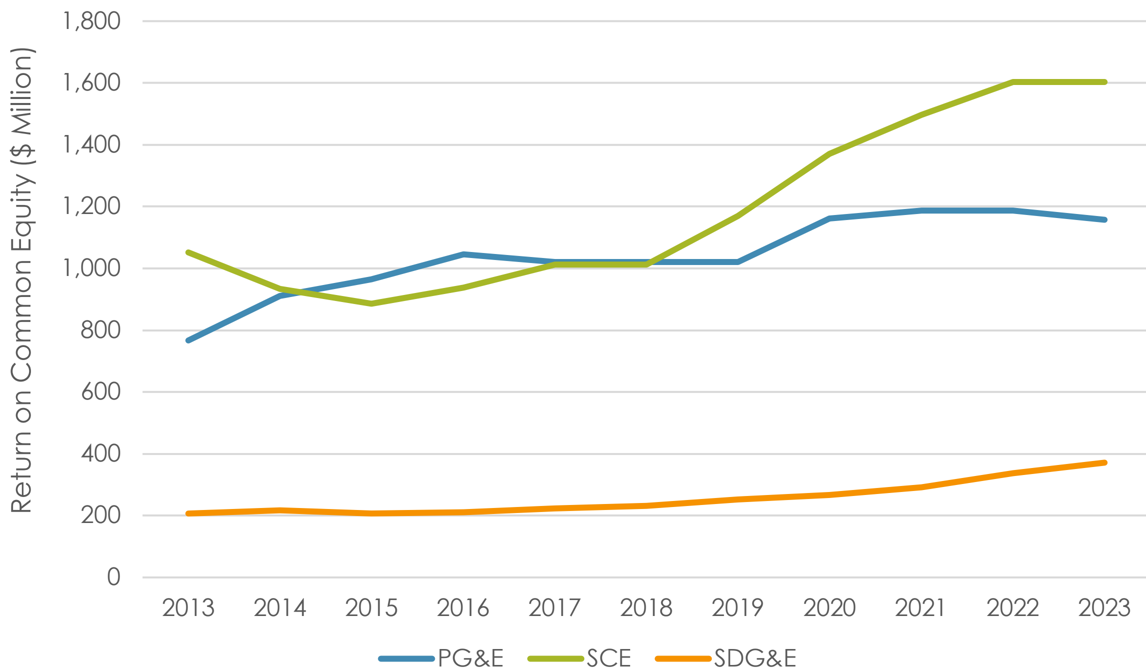


Figure 3.7 shows trends in dollars authorized for return on common equity for major energy utilities since 2013. The figure does not include return on common equity authorized by FERC for IOU transmission systems; it includes only the return on common equity authorized by the CPUC for UOG and distribution.

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.

Transmission Revenue Requirement

Background and Jurisdictional History

As part of energy restructuring, the CAISO was created by the legislature and given operational control[34] over the utilities' FERC jurisdictional transmission lines on March 31, 1998, and authority for determining transmission revenue requirements was transferred

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

to FERC.[35] 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 system and under FERC jurisdiction if they are at a higher voltage and meet FERC criteria for connectivity in the transmission system. 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, and if they meet the configuration requirements to make them part of the interstate transmission system, these transmission assets fall under CAISO's operational control and are regulated by FERC.[36] All other electric power lines and assets remain under CPUC regulatory control and jurisdiction.

The three major IOUs file Transmission Owner (TO) formula rate cases at FERC, establishing rates of depreciation, cost of capital, and other elements of their ratemaking framework that typically remain in effect for several years. A formula provides 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[37], advocating for just and reasonable rates for California consumers in TO rate cases. Due to the importance and complexity of these rate cases, CPUC Legal Division and Energy Division staff analyze a multitude of expenses and capital projects for cost effectiveness, reliability, safety, and overall prudence of expenditures. Specific transmission revenue requirement (TRR) components examined include return on equity, capital structure, taxes, depreciation, cost-of-service, and the forecast transmission capital project costs. 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.

[35] 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).

[36] 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.

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

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. While FERC issued its final order on TO18 in March 2022, requests for rehearing have delayed refunds being issued to ratepayers. With interest, it is expected that the total TO18 refunds to ratepayers will exceed $300 million. Further, the settled outcome of TO19 (for 2018 rates) is tied to a final non-appealable decision in TO18 and is expected to yield additional refunds approaching $400 million for ratepayers.

In October 2018, PG&E filed its Twentieth Transmission Owner Formula Rate Case (TO20) at FERC. Settlement of all issues was accepted by FERC on December 30, 2020, with the term of the formula rate effective through 2023. In addition to reaching settlement on the TRR, the CPUC had success negotiating the establishment of the Stakeholder Transmission Asset Review (STAR) Process. As over 82 percent of PG&E's transmission capital projects since 2020 (i.e., over $1 billion annually) received no formal review 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.

PG&E's Total TRR in 2023 was $3.27 billion, over $320 million more than the TRR in 2022 (i.e., $2.95 billion). The 2023 TRR in just the TO rate case was $109 million higher due in part to greater O&M expenses, including wildfire-related vegetation management, as well as other upgrades for grid operations to support external projects on work at the request of others (WRO).   Another contributing factor was an increase of over $180 million in PG&E's Transmission Access Charge Balancing Account Adjustment, which was a charge to ratepayers of $492 million to make PG&E whole for under-collection at the CAISO for others' use of the PG&E transmission grid.

FERC approved the settlement in SCE's most recent TO rate case on September 23, 2020. The settlement required annual informational filings to correct any under- or over-collection of approved expenses from the previous year. For 2023, SCE's increase in its rate case TRR was principally attributed to: a large cost adjustment due to an increase in administrative and general (A&G) expenses related to an upward adjustment to the 2017/2018 wildfire reserve, a net increase of FERC-jurisdictional rate base, and partial offsets due to reductions in True-Up adjustments and aerial inspections, vegetation management, and Covid-related expenses that impacted O&M costs. As mentioned in the Overview section, a large credit in the Transmission Revenue Balancing Account Adjustment offset these increases, resulting in an overall reduction in net transmission costs.

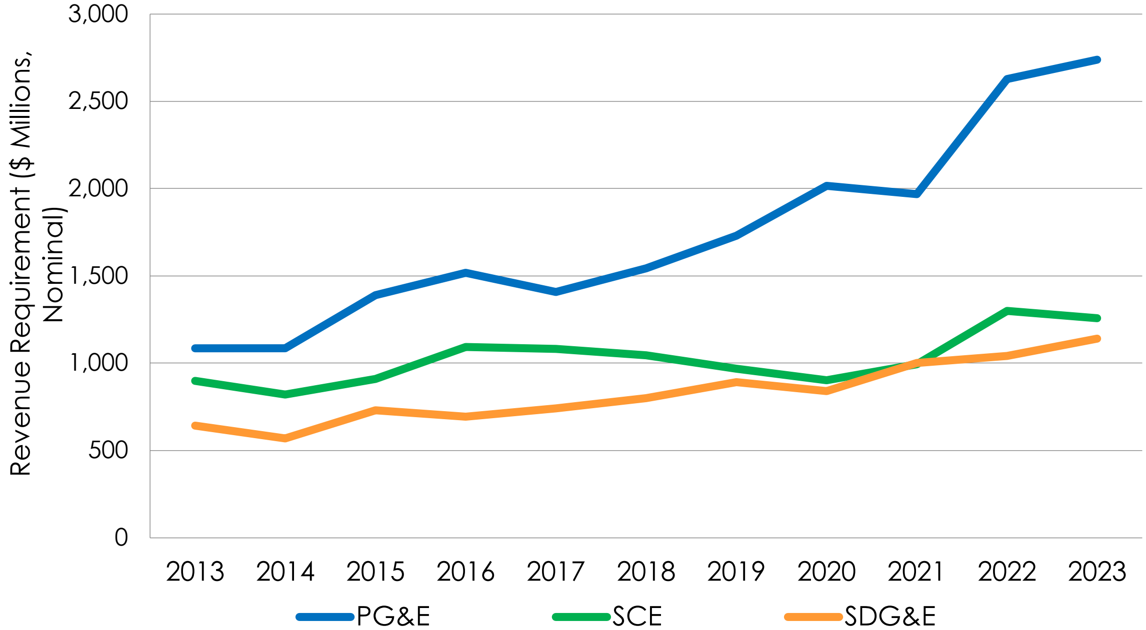
Further, as part of the FERC settlement, SCE committed to establish and implement the Stakeholder Review Process (SRP) for review of SCE's Five-Year Transmission Investment Plan for transmission projects and costs. SCE submitted its seventh and final semi-annual SRP dataset to stakeholders on December 1, 2023, and the SRP expired on December 31, 2023.

FERC approved the settlement in SDG&E's fifth formula rate case (TO5) on January 24, 2020. SDG&E files annual updates with FERC to set transmission rates for the coming year and reconcile differences between the prior year's forecast and actual expenditures. SDG&E's 11.3 percent increase in total TRR in 2023 can be attributed to: higher O&M costs, depreciation expenses, property and payroll taxes, a 6 percent increase in the transmission rate base, and an increase in franchise fees and uncollectibles.

The estimated savings to California ratepayers from the CPUC's advocacy in FERC TO rate cases over the last decade exceeds $5 billion.

Even with the savings for ratepayers secured by the CPUC's efforts, rate case transmission revenue requirements for the IOUs have been trending upward since 2013, increasing at an average annual growth rate of 9.7 percent for PG&E, 3.4 percent for SCE, and 5.9 percent for SDG&E as shown in **Figure 3.8**.

Figure 3.8: Trends in TO Rate Case Transmission Revenue Requirement[38]



Historically, much of the increase in the utilities' revenue requirements was due to transmission infrastructure capital investments. Years ago, large additions to utilities' rate base included CAISO-approved reliability projects and those needed for meeting clean energy mandates. These projects expand capacity of the grid, enabling interconnection of new electric generation, as well as compliance with North American Electric Reliability Corporation (NERC) requirements.

The current trend in transmission capital investment shows that all three electric utilities continue to increase their spending 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. They include any projects that do not expand the capacity of the transmission grid and therefore do not go through the CAISO's Transmission Planning Process. These are repair and replacement projects that are needed for maintaining the grid, yet the lack of review does not make it clear to ratepayers that these are the most needed transmission projects, particularly as other work, particularly capacity expansion projects and upgrades, are subject to significant and costly delays. The three electric utilities report that from 2013 to 2022, these self-approved transmission projects accounted for 49.8 percent ($10.9 billion) of their collective transmission

[38] 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.

investment. However, in just the last three years for which the CPUC has actual data (i.e., 2020 to 2022), 64.8 percent ($4.4 billion) of the electric utilities' investments were on self-approved projects, as 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

	2013-2022 ($M)	2020-2022 ($M)
Total IOU Transmission Capital Projects	21,890	6,792
Self-Approved Capital Projects	10,897	4,398
Percentage of Self-Approved Projects	49.8%	64.8%

While FERC has found that these self-approved projects do not fall under the transparent planning requirements of existing FERC regulations, the CPUC and other stakeholders had success in 2020 negotiating PG&E's Stakeholder Transmission Asset Review (STAR) Process and SCE's Stakeholder Review Process (SRP) in their respective TO rate cases at FERC. These stakeholder processes improved transparency of the two utilities' transmission capital projects.

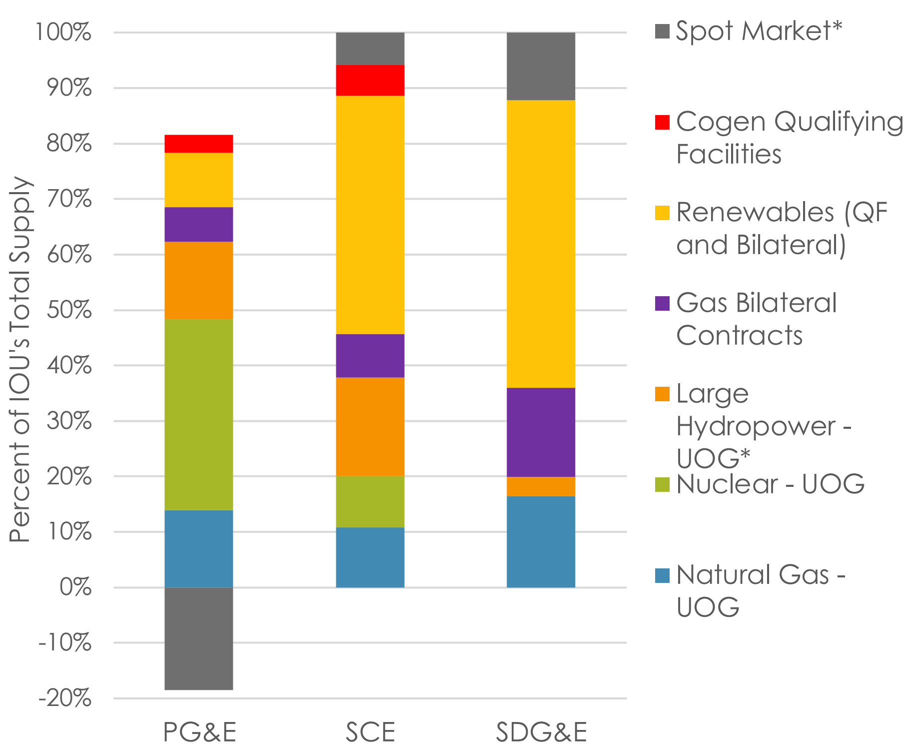
Anticipating the expiration of the STAR Process and SRP at the end of 2023, the CPUC established the Transmission Project Review (TPR) Process in Resolution E-5252 in April 2023. The TPR Process enhances the level of data included in the STAR Process and SRP, now includes SDG&E, and establishes uniformity 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. Energy Division's FERC Cost Recovery Section has been playing a significant role in FERC rulemakings, technical conferences, and advising CPUC Commissioners in their roles 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 2023, purchased power accounted for approximately 68 percent of the total generation revenue requirement (see **Figure 4.1**). Power purchase costs represented the largest component of forecasted generation costs and accounted for 21 percent of total revenue requirements. Recovery of these pass-through costs is authorized through the ERRA proceedings. The sale of purchased power is expensed, not capitalized.

Figure 4.1: 2023 Forecast Energy Supply for Electric Utilities



*Spot Market includes sales of surplus energy and interutility and other purchased power sources. Large Hydropower – UOG includes other UOG fuel sources.

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. To create a competitive electricity market in which non-utility suppliers would compete with the utilities in the wholesale generation market, 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. As a result, the utilities sold a substantial portion of their fossil-fueled generation.

During the 2000-01 energy crisis, the utilities were exposed to high market prices for electricity, due in large part to the divestiture of their generating plants. Authorized utility rates, which were frozen at pre-restructuring levels from June 1996, were no longer sufficient 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 1X, which authorized the DWR to enter into power purchase contracts to stabilize the severely disrupted energy markets.

In 2002, the Legislature enacted AB 57 to return energy procurement responsibilities to the utilities. The legislation required the CPUC to adopt a Long-Term Procurement Plan to ensure sufficient resource availability over time. 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[39] that the CPUC required the IOUs to create.

AB 380 (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 maintain a 15-17 percent planning reserve margin for generating capacity to ensure they have sufficient capacity available or under contract to serve their forecasted load.

In addition, SB 1078 (2002) established the RPS 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.

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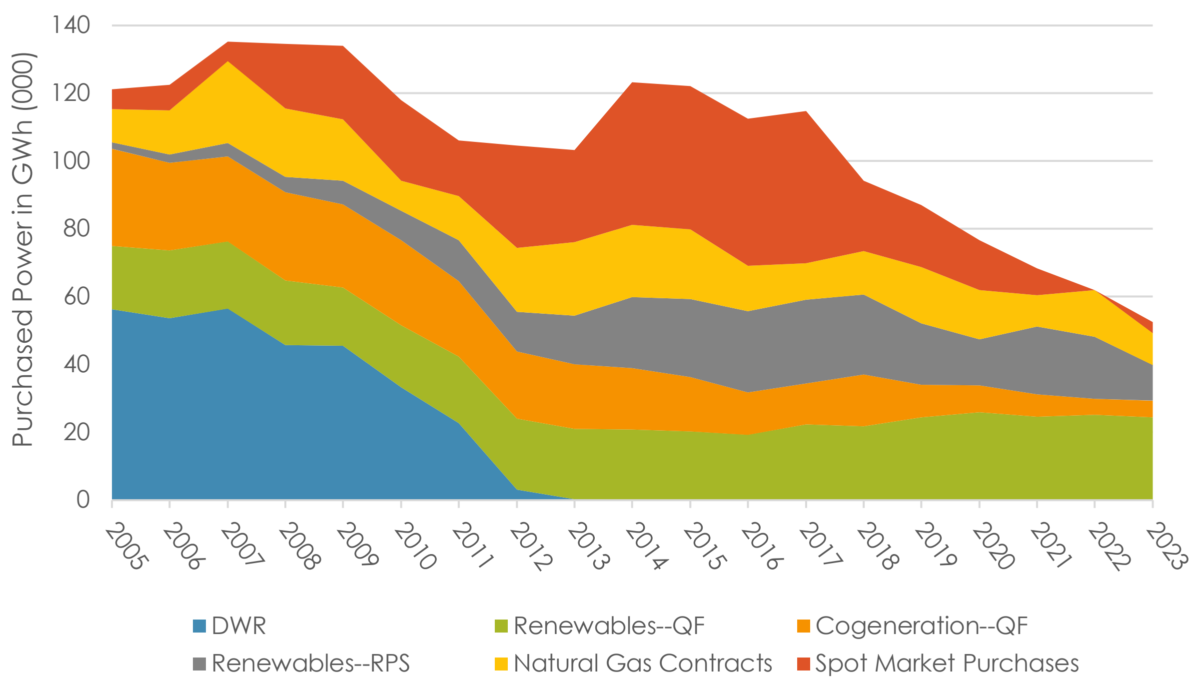
[39] A Commission authorized forum that reviews procurement activities including contracts and reasonableness criteria and offers assessments and recommendations to each utility. The Commission initially established Procurement Review Groups (PRG) in D.02-08-071 as an advisory group to assess the investor-owned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

SB 107 (2006) later increased the RPS obligation to 20 percent by 2010 and was updated by SB 2 (2011) when the RPS obligation was raised to 33 percent by 2020. SB 350 (2015) raised the RPS obligation to 50 percent by 2030. In 2018, SB 100 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 established a 90% clean energy standard in 2035, a 95% clean energy standard in 2040, and also clarified that eligible renewable energy resources and zero-carbon resources should supply 100% of all retail sales of electricity to California end-use customers by December 31, 2045, and 100% of electricity procured to serve all state agencies by December 31, 2035.

Purchased Power

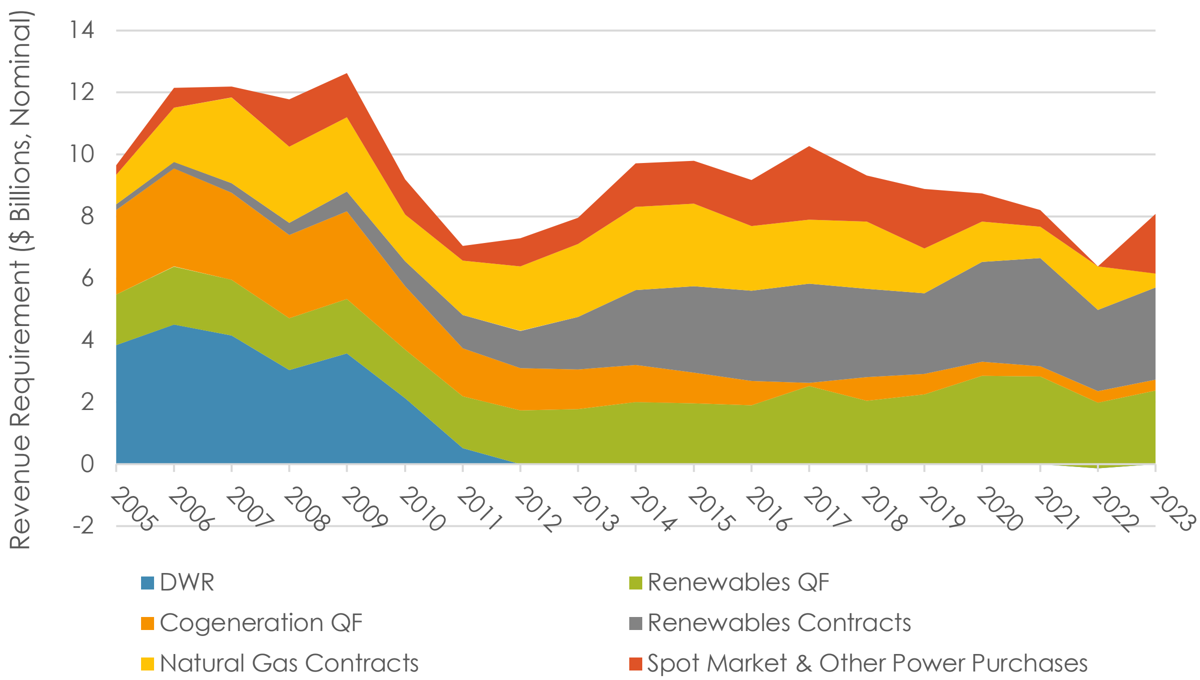
Since 2005, purchased power supply has decreased due to the migration of load from the IOUs to Community Choice Aggregators, which reduced the IOUs' demand. Since the first CCA, Marin Clean Energy, formed in 2009, 38% of total load has departed the IOU to be served by CCAs. As a result, the revenue requirement 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. Since 2018, the IOUs have decreasingly relied on procurement of energy through the CAISO energy market, with only 6% of the total load supplied by spot market purchases in 2023.

Figure 4.2: Trends in Purchased Power Supply (GWh)



While total purchased power supply has decreased by 56% since 2005, the revenue requirement for purchased power has only decreased by 16%. 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

<u>Department of Water Resources (DWR) Contracts</u>

The California Department of Water Resources (DWR) entered into long-term contracts on behalf of IOU customers during the energy crisis. Each year, DWR had 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. Proceeds from litigation related to these contracts is possible in the coming years and will result in future refunds to customers if realized.

<u>Qualifying Facilities (QFs)</u>

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.[40] 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.[41] The Settlement ended in 2020, with SDG&E required to do an additional CHP solicitation in 2022 to meet its obligations under the Settlement.[42] 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.[43] In 2022, the CPUC modified the SOC to allow for storage-paired QFs.[44]

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 IOUs are currently on track to meet their 60 percent by 2030 RPS target requirements through their procurement of renewables generation and use of their prior excess procurement of renewable energy or "banked" renewable energy credits, or RECs. In addition to banking excess RECs, for the past several years the IOUs have sold small quantities of their excess REC supply and returned the revenue of these sales to ratepayers and allocated or sold portions of their RPS portfolios through the Voluntary Allocation and Market Offer (VAMO) process. After accounting for the sale of excess RECs and voluntary allocations, the IOUs forecast having served 48.4 percent of their electricity demand with RPS eligible resources in 2023. The IOUs have forecasted RPS percentages over 41 percent in 2024 and beyond. The weighted average RPS procurement expenditures for the IOUs decreased from 12.4 ¢/kWh in 2021 to 10.5 ¢/kWh in 2022, in real dollars.

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[40] QF costs include Competition Transition Charges (CTC). For a breakout, see table in Appendix A.

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

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

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

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

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 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:** 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.

Utilities accrue costs for the Cap-and-Trade Program as both direct and indirect costs. In 2023, the electric utilities collectively included approximately $298 million in direct GHG costs into rates to bundled customers and returned approximately $896 million in allowance proceeds to bundled customers in the form of customer credits (see **Table 4.1**). The electric utilities returned another approximately $555M 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 (2023 Electric IOU Authorized Revenue Requirements) but are not reported separately in this section.

Table 4.1: 2023 Summary of Greenhouse Gas Costs and Allowance Proceeds[45]

Utility	2023 Electric GHG Direct Costs Revenue Requirement[46]	2023 Electric Proceeds Distributed to Bundled Customers	2023 Electric Proceeds Distributed to Unbundled Customers
PG&E		($233,430,085)	($244,288,930)
SCE		($497,195,898)	($225,384,956)
SDG&E		($96,846,341)	($85,278,765)
Total	**$298,516,089**	**($896,497,128)**	**($554,952,651)**

Each year, CARB allocates allowances to electric utilities on behalf of their ratepayers. The Cap-and-Trade Program requires the investor-owned electric utilities 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 (2006), CARB regulations, and as directed by the CPUC. Consistent with the direction in

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[45] Proceeds recorded through September 30, 2023 and estimated through December 31, 2023. Costs recorded through July 31, 2023 and estimated through December 31, 2023 for SCE; forecast for PG&E and SDG&E. Costs for bundled customers only.

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

SB 1018 (2012), the CPUC has determined the methodologies the utilities should use to return proceeds to industrial customers[47], 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 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, 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 third consecutive year, in 2023 SOMAH was funded at the full $100 million ceiling. 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.[48] DAC-GT and CSGT above-market generation costs are funded with allowance proceeds and the 20 percent customer discount, program administration, and marketing, education, and outreach costs are funded through public purpose programs (PPP) funds. Additionally, in 2019 the CPUC also approved use of $20.4 million by SCE for a Clean Energy Optimization Pilot, of which the final $0.4 million was appropriated from Cap-and-Trade funds in 2023. An inventory of demand side management programs funded out of the IOUs' GHG auction proceeds can be found in section V.

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 over time. Natural gas prices and capacity prices are other factors that can have a significant effect on the cost of many types of generation.

> **Natural Gas Prices:** Natural gas prices cause generation costs to be more volatile than other forms of generation. Electric spot market purchases and cogeneration QFs costs fluctuate and track with gas prices. Natural gas bilateral contracts do not track as closely with gas prices, as most of the costs of those contracts are associated with capacity and not energy. Renewables contracts generally exhibit more cost stability because they are not reliant on gas prices.
>
> **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

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

[48] 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.

increase. Capacity prices for new resources are also sensitive to supply chains, changes to tax laws (i.e. Inflation Reduction Act tax credit), and interconnection delays which can also have significant impacts on costs. If generation costs are significantly higher or lower than forecasted,[49] the affected utility must file an ERRA Trigger notification with the CPUC's Energy Division. If the utility does not believe that the difference will be within the authorized threshold amount within 120 days, it files an expedited ERRA application (Trigger) that corrects rates to be in line with the costs the utility is experiencing. The Trigger application maintains rate stability if the costs associated with fuel and purchased power vary greatly from forecasted amounts.

The CPUC conducts annual Compliance ERRA reviews that true-up any difference from the utility's forecasted revenue requirement to the actual costs incurred regardless of whether or not a Trigger application was filed.

The price of natural gas in California reached record 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 have been modest due to higher storage inventories, no major pipeline outages, and milder weather.

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. 2021 was also a major drought year. Drought years in the western states mean less hydroelectric generation available and thus more reliance on natural gas-fired generation; all else equal, this tends to increase electricity prices. Additionally, there was particularly cold and wet weather in winter 2022-2023 that contributed to an increase in natural gas and electricity prices during that time. 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.

[49] The utility must alert the CPUC if a balance grows to greater than 4 percent more or less than revenue requirement per D. 02-10-062; if the balance is expected to cross 5 percent the utility must file an expedited application known as an "ERRA Trigger Application".

V. Demand-Side Management and Customer Programs

The Demand-Side Management (DSM) work that the CPUC oversees is characterized by a mix of energy efficiency (EE), demand response (DR), and distributed generation (DG) programs, serving all sectors of the California economy. For nearly half a century, the CPUC has overseen policies to encourage energy conservation, efficiency and load management. In 2003, the CPUC and the California Energy Commission adopted the Energy Action Plan to establish goals for the state's energy strategy.[50] The plan established that cost-effective energy efficiency and demand response are at the top of the loading order and are therefore the preferred means for meeting the state's growing energy needs, followed by renewable energy and distributed generation.

In addition, California has led the nation in customer-side solar and other DG technology market growth, supported by net energy metering (NEM) and net billing tariffs first established in 1996 and 2023 respectively,[51] the Self-Generation Incentive Program (SGIP) enacted in 2000, and, later in 2006, the landmark California Solar Incentive (CSI) program, both overseen by the CPUC. For decades the CPUC has administered low-income EE programs (now called Energy Savings Assistance or ESA) to assist vulnerable populations in managing their energy bills,[52] and takes input on these and other programs from the Low-Income Oversight Board (LIOB) established by the Legislature in 2001.[53]

[50] The Energy Action Plan was updated in 2005 and 2008.

[51] Most of the NEM tariffs were closed to new enrollment in 2023-2024 and were succeeded by net billing tariffs. The new tariffs reduce greenhouse gas emissions by increasing the proportion of customer-side solar that is consumed onsite by the customer, especially at hours of peak electricity demand.

[52] PU Code Section 2790.

[53] SBX 2 (2001, Alarcon).

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

Table 5.1: 2023 Demand Side Management and Customer Programs Costs ($000)[54]

	PG&E	SCE	SDG&E	Total
Energy Efficiency	337,492	405,006	117,574	**860,072**
Demand Response	75,060	39,005	10,852	**124,917**
California Solar Initiative	0	0	0	**0**
Self-Generation Incentive Program	59,895	56,626	20,069	**136,591**
Electric Program Investment Charge	96,716	76,885	16,280	**189,881**
California Alternative Rates for Energy Admin	189,668	(74,272)	79,000	**194,396**
Energy Savings Assistance	(34,850)	61,811	14,728	**41,690**
Other PPP Programs[1]	229,295	237,357	232,960	**699,612**
Other Regulatory[2]	1,068,379	543,209	139,637	**1,751,224**
Total	**2,021,657**	**1,345,627**	**631,100**	**3,998,384**

1. 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 Schools Energy Efficiency Stimulus Program for SCE, and CARE for SDG&E (distinct from CARE administrative costs shown elsewhere in the table).
2. Other Regulatory costs are comprised mostly of Wildfire Mitigation and Catastrophic Events charges for PG&E, the Wildfire Fund Non-Bypassable Charge for SCE, and costs related to the Liability Insurance Premium Account for SDG&E.

Energy Efficiency

In 2003, the California Energy Action Plan set energy efficiency at the top of the loading order, determining that the state should maximize all cost-effective energy efficiency investment over 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, which are updated periodically as provided for in that decision. The CPUC-adopted energy savings goals are expressed in terms of annual and cumulative gigawatt hours (GWh), million-therms (MMtherms), and peak megawatt (MW) load reductions. It is worth noting that in D.21-05-031, the CPUC adopted a new single metric, the Total System Benefit (TSB), which expresses the lifecycle energy, capacity, and GHG benefits in dollar terms on an annual basis.

[54] Revenue requirement for Demand Side Management, California Solar Initiative, Self-Generation Incentive Program, and other regulatory is collected through the distribution rate component.

Starting in 2024, the TSB metric will replace kWh, kW, and Therm savings as the primary goal for the energy efficiency portfolios.

The gas portion of the energy efficiency portfolios is funded through the gas Public Purpose Program (PPP) component of rates. The electric portion is funded through the Procurement Energy Efficiency Balancing Account (PEEBA) to reflect the avoided generation and transmission and distribution upgrades that result from reduced electricity demand. The aggregated annual expenditures are approximately $405 million for 2022 and 2023 together (see **Table 5.2**).

Programmatic efforts in 2022 and the first three quarters of 2023 resulted in reported program savings of 2,052 GWh, 349 MW, and 72 MMtherms.[55] According to the EPA,[56] that is enough electricity savings to power about 172,721 homes for one year, and enough gas savings to avoid the need for about one-tenth of a coal power plant.

These programs support residential, public, commercial, industrial, and agricultural sectors to overcome barriers to improving energy efficiency and realize savings for the ratepayer. In addition to the directly quantifiable savings and benefits, the CPUC also supported programmatic activities targeted at the long-term transformation of consumer energy markets through 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 done so.

[55] Reported savings estimates are net and are available from CEDARS (https://cedars.sound-data.com/).

[56] Equivalencies estimated using the EPA Greenhouse Gas Equivalencies Calculator (https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator).

Table 5.2: Energy Efficiency Savings and Expenditures from Non-Codes and Standards IOU Program[57]

Year	2023	2022	Grand Total[58]
All Investor-Owned Utilities			
Electric (GWh)	**320**	**2052**	**2372**
Demand (MW)	**55**	**349**	**404**
Natural Gas (MMTh)	**20**	**72**	**92**
Carbon (1000 Tons CO2)	**1044**	**448**	**1492**
Total Expenditures ($M)	**206**	**405**	**611**
PGE			
Electric (GWh)	231	1797	**2028**
Demand (MW)	51	300	**351**
Natural Gas (MMTh)	9	44	**53**
Carbon (1000 Tons CO2)	505	219	**724**
Total Expenditures ($M)	79	192	**271**
SCE			
Electric (GWh)	80	199	**279**
Demand (MW)	3	36	**39**
Natural Gas (MMTh)	0	0	**0**
Carbon (1000 Tons CO2)	262	53	**315**
Total Expenditures ($M)	52	92	**144**
SoCalGas			
Electric (GWh)	2	4	**6**
Demand (MW)	1	3	**4**
Natural Gas (MMTh)	11	26	**37**
Carbon (1000 Tons CO2)	160	152	**312**
Total Expenditures ($M)	50	86	**136**
SDGE			
Electric (GWh)	7	52	**59**
Demand (MW)	1	10	**11**
Natural Gas (MMTh)	1	2	**3**
Carbon (1000 Tons CO2)	117	24	**141**
Total Expenditures ($M)	25	35	**60**

[57] 2023 data does not include fourth quarter data which will be available May 1st, 2024; 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 total IOUs EE filing budget for 2023 was $807 million.

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

Demand Response

Per D.17-12-003, Demand response is defined as "reductions, increases, or shifts in electricity consumption by customers in response to either economic signals or reliability signals." Effective demand response programs provide California ratepayers with various economic and environmental benefits, such as:

- Saving ratepayer money by deferring capital expenditures to build power plants and transmission infrastructure that would otherwise be necessary to meet peak demand.
- Decreasing the price of wholesale energy and avoiding the purchase of high-priced energy.
- Providing greater reliability to the grid, which helps prevent blackouts.
- Avoiding the consumption of fossil fuels which can reduce GHG emissions.

Evolution of Demand Response Programs

When the Commission established the first generation of Demand Response (DR) programs in the 1980s the DR programs were initially aimed at large commercial and industrial customers that can shed significant amounts of load as response to grid emergencies. With the advent of smart meters, smart thermostats, batteries, and other smart devices, DR programs for residential customers were introduced and residential customer participation in DR has grown over time.

There are currently two categories of DR programs.

A) Load-Modifying DR (LMDR) are those that operate outside the CAISO market, including 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 their daily peak and off-peak periods, are reflected in the California Energy Commission's load forecast, and so indirectly provide resource adequacy credit to load serving entities. In the 2022 Demand Flexibility Rulemaking discussed below, the Commission is moving to dynamic rates that reflect actual CAISO market prices, and grid conditions on an hourly basis.

B) Supply-side DR (SSDR) are event-based programs integrated into the CAISO electricity markets. Utility-managed SSDR include the Base Interruptible Program (BIP), Capacity Bidding Program (CBP), and Air Conditioning Cycling (A/C Cycling) are bid as a capacity resource into CAISO energy markets, enabling them to compete against generation bids and to be dispatched as needed by the CAISO. DRAM (discussed below) allows third party resources to provide capacity to the IOUs while they participate in the CAISO. Finally, all LSEs including

(IOUs and CCAs) can procure Supply-side DR resources through bilateral RA contracts.

The Demand Response Auction Mechanism (DRAM) pilot provides a pathway for third-party DR providers and their customers to receive resource adequacy (RA)-eligible capacity payments for providing load reduction services during periods of peak electricity demand or high energy market prices. Under the DRAM pilot, utilities procure RA capacity through competitive bids offered by third party DRPs in an annual auction process.

Pursuant to CPUC decisions, the IOUs were authorized to conduct annual DRAM auctions starting in 2016, with the most recent DRAM procurement resulting in 157MW (August capacity) of DR resources for delivery in 2024. From 2016-2024 August capacity contracted from DRAM averaged 171 MW a summer. However, one internal study[59] and one independent third-party study[60] found that the DRAM resources did not reliably make themselves available or show up when called, especially during times of critical grid need. The future course of DRAM beyond 2024 is expected to be decided by the CPUC in the currently open A.22-05-002 proceeding.

In addition to DRAM the third party DRPs establish bi-lateral DR contracts with LSEs (IOUs and CCAs). In August 2023, there were 142 MW of 3rd-party DR procured by LSEs through the LIP process. In 2024, seven DR providers completed the review process and were authorized by the Commission to deliver 235 MW of RA-eligible DR capacity in August 2024. The actual amount of 2024 contracted MWs depends on LSE RA contracts and is reported to the Commission on a monthly basis.

In December 2023, the Commission approved the IOUs' 2024-2027 DR programs and authorized $1.55 billion in total DR funding.[61] SCE was authorized $812.02 million, PG&E was authorized $616.01 million, and SDG&E was authorized $120.65 million.

Summer Reliability

Recently, the Commission has expanded the role of demand response resources to help address reliability concerns due to extreme weather in summer months.

- D.21-03-056 in Phase I of the Summer Reliability proceeding established the Emergency Load Reduction Program (ELRP) as a pay-for-performance demand

[59] Energy Division Report: Evaluation of the Demand Response Auction Mechanism (as an Attachment to Administrative Law Judge's Ruling Issuing Evaluation Report of the Demand Response Auction Mechanism Pilot, Noticing January 16, 2019 Workshop, and Denying Motion to Require Audit Reports in the Evaluation Reports - https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M254/K771/254771618.PDF

[60] Demand Response Auction Mechanism Evaluation, Nexant - https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M502/K977/502977264.PDF

[61] D.23-12-005 Decision Directing Certain Investor-Owned Utilities' Demand Response Programs, Pilots, and Budgets for the Years 2024-2027.

response program that compensates voluntary load reduction provided by a participating customer during a program event triggered in response to CAISO-declared grid emergencies. Customers eligible to participate in ELRP included directly enrolled non-residential customers, virtual power plant (VPP) aggregators, and customers with Electric Tariff Rule 21 exporting Distributed Energy Resources (DERs).

- D.21-12-015 in Phase II of the Summer Reliability proceeding increased the ELRP compensation rate to $2 per kWh of incremental load reduction achieved by the customer. Eligibility for participation in ELRP was expanded to non-residential aggregators, electric vehicle/charging station aggregators (including both V1G - vehicle charging and V2G - vehicle discharging into the grid), and nearly four million residential customers automatically enrolled in Power Saver Rewards. Program event triggers for residential customers were expanded to include Flex Alerts.

  D.23-12-005 in the DR Application proceeding (A.22-05-002) reduced the dispatch window for virtual power plant and vehicle-grid-integration aggregators to ensure load reduction at most critical hours. It also extended the sunset date for nonresidential and market-integrated resources from 2025 to 2027 to ensure midterm reliability. The Residential Power Saver Rewards Program will sunset at the end of 2025. To increase the cost-effectiveness of the program, the compensation rate for residential Power Saver Rewards was reduced to $1/kWh. The compensation for all other sub-groups will remain at $2/kWh.

- Additionally, the CPUC adopted several enhancements to IOU DR programs, expanded the smart thermostat program to fund about 300,000 new thermostats in hot climate zones, with the customer required to participate in a supply-side DR program, and directed PG&E and SCE to implement hourly dynamic rate pilots for agricultural water pumping and other end uses.

2024-2027 Demand Response Budget Applications

In December 2023, the Commission approved IOU Demand Response Budgets for program years 2024 through 2027. Beyond the ELRP improvements described above, this Decision also strengthened incentive signals for two long-running DR programs.

- The Base Interruptible Program (BIP) offers monthly incentives to commercial and industrial customers who commit to rapidly shed load upon dispatch during grid emergencies.
  - The Decision authorized an increase of $2/kW in PG&E's monthly BIP customer incentives between May and October.
  - The Decision authorized SCE to submit increased BIP incentive levels through the Advice Letter process, subject to certain guidelines. ED staff is currently working with SCE to implement substantially increased incentive levels, especially for the large industrial customers that make up the bulk of BIP's interruptible capacity.

- CBP incentives were increased for both PG&E and SCE in the Decision to levels requested in each's original Applications. PG&E increased its incentive levels from $11.10/kw to $12.71 kW on average for the May-October period of the program's operation. Every month saw an increase with the largest increases coming in May and June. SCE's CBP was reduced from year-round to May-October. The average incentive rose from $11.39/kw to $13.21/kw. SDG&E did not request an increase in incentives and their incentive levels will remain unchanged.

Future Demand Response

Future DR programs are expected to help integrate increasing amounts of renewable power onto the grid by shifting electric loads to periods of high renewable generation. There may also be a significant role for DR to alleviate electricity supply shortages in certain local areas of the state with constraints on transmission capacity. To facilitate this, the Commission in July 2022 opened a new rulemaking to establish demand flexibility policies and introduce hourly marginal-cost based electric rates to help enhance system reliability, reduce curtailment of renewable energy, and reduce electricity costs of service among other objectives. Two working groups in the rulemaking produced reports in September 2023 drawing on hourly cost-based rate design and related ideas from the June 2022 Energy Division staff whitepaper: Advanced Strategies for Demand Flexibility Management and Customer DER Compensation.[62] This 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 Commission 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. Decision 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 Community Choice Aggregators. 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 for the expansion, between SCE and PG&E, is 150 MW.

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[62] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/demand-response-workshops/advanced-der---demand-flexibility-management/ed-white-paper---advanced-strategies-for-demand-flexibility-management.pdf

Customer Generation

The CPUC has taken actions that support the development of customer-sited distributed energy resources and related technologies by providing financial incentives to customers and project developers. Its Distributed Generation (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 new net billing tariff (NBT) provide customer-generators with bill credits for power generated by their onsite systems that is fed back into the grid.

Table 5.3: 2023 GHG Auction Proceeds Funded Demand Side Management and Customer Programs ($000)[63]

	PG&E	SCE	SDG&E	Total
Disadvantaged Communities Single-Family Solar Homes, Green Tariff & Community Solar Green Tariff	35,346	7,539	1,735	**44,620**
Solar on Multifamily Affordable Housing[64]	42,667	47,048	15,130	**104,845**
Total	**78,013**	**54,587**	**16,856**	**149,465**

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

AB 327 (Perea, Chapter 822, Statutes of 2013) required the Commission to develop "specific alternatives designed for growth [in adoption of renewable generation] among residential customers in disadvantaged communities." The Commission determined that installations under the Solar on Multifamily Affordable Housing (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 in accessing renewable energy. Thus, D.18-06-027, adopted in June 2018, established three

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

[64] Solar On Multifamily Affordable Housing (SOMAH) program includes current year funding and prior year true-up amounts. A SOMAH funding year cannot exceed $100M per D.17-12-022 and Public Utilities Code 2870. The amounts in in this table are more than $100M since it includes prior-year true-up amounts which are not subject to a given year's $100M cap.

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 Single-family Solar Homes (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 Commission 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 2023, DAC-SASH had helped install 2,309 rooftop solar systems, totaling 8.96 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 available to customers who meet the income eligibility requirements for the CARE and FERA programs. As of October 2023, approximately 24,000 customers have been enrolled using interim Renewable Portfolio Standard (RPS) resources and 73.89 MW of new solar projects were approved, the first of which is scheduled to become operational in 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. As of October 2023, 357 customers were enrolled and 18.37 MW of new solar projects were approved, the first of which is expected to become operational in 2024.

Proceeding A.22-05-022 et al. is currently evaluating whether to retain, modify or terminate existing customer renewable energy subscription programs including DAC-GT, CSGT and the Green Tariff Shared Renewables (GTSR) programs in accordance with AB 2316 (Ward, 2022) and AB 2838 (O'Donnell, 2022). The proceeding is also considering whether it would be beneficial to ratepayers to establish a new community renewable energy program with a focus on the California Building Standards Code, low-income participation, minimizing impacts to non-participating customers, prevailing wages, bill credits based on avoided costs, and utilizing state and federal incentives.

Solar on Multifamily Affordable Housing (SOMAH) Program

AB 693 (2015) 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 that 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 (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.[65]

- 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.[66] The evaluator also determined that SOMAH will remain on track to reach its 300 MW installation goal if new strategies for outreach and reducing participation barriers are realized. The CPUC had previously recognized that the program needed adjustment and approved a higher incentive rate in March of 2023 (Decision 23-03-007). Now properties can receive up to $3.50/watt for solar capacity supporting tenants and up to $1.19/watt for solar capacity support common areas.[67] A ruling was issued on May 5, 2023, asking parties to provide further input on program modifications, with a focus on increasing participation in disadvantaged communities.

As of January 2024, the program has 527 active applications, with 30 percent of these in disadvantaged communities. There are 109 completed projects with 36 percent in disadvantaged communities, and these projects in total received approximately $33.7 million in incentives. For completed projects, the average system size was 160 kW and were given an average incentive of $309,000. Active applications and completed projects together equaled 73.72 MW, or 25 percent of the way to the program's 300 MW goal.

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

[66] 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)

[67] SOMAH resources available at: www.calsomah.org/incentives-finance

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. Since the program's inception, over $1.6 billion in SGIP incentives have been paid out or reserved to over 48,000 projects comprising almost 1.4 gigawatts of capacity. In 2023, almost $148 million was paid out or reserved to over 9,200 projects comprising 140 MW of capacity; all but $124 million went to energy storage systems.

- AB 209 (2022) authorized $900 million in legislatively appropriated state General Fund monies for the first time to SGIP. $630 million was proposed in the Governor's January 2023 budget 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. $270 million for general market incentives may be included in a future budget.
- The original AB 209 $900 million budget was reduced to $630 million and spread over three fiscal budget years. AB 102, Stat., of 2023, Ch. 38 amended the Budget Act of 2023 and was passed by the California Legislature on June 27, 2023, and signed into law by the Governor on July 10, 2023. AB 102 allocated $280 million to the Commission in Fiscal Year (FY) 2023-24.
- The $280 million provided in the 2023 Budget were appropriated from the Greenhouse Gas Reduction Fund (GGRF), which is where the State's portion of the Cap-and-Trade auction proceeds are deposited.
- On February 2, 2024, The Proposed Decision for AB 209 mailed, the $280 million funds added to SGIP can be used by all eligible low-income California residential customers who install either new behind the meter solar PV systems paired with energy storage or new standalone energy storage systems.

Additional SGIP Program History

- The program was reauthorized by SB 700 (2018) to continue ratepayer collections through 2024 and program administration through 2026. Pursuant to SB 700, the CPUC authorized ratepayer collections of $166 million annually for the years 2020 to 2024 in D.20-01-021 for a total of $830 million. The program funds are collected from PG&E, SCE, SDG&E, and SoCalGas.

- CPUC D.20-01-021 allocated the $830 million authorized in new 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 created in D.19-09-027. This budget provides the highest incentive level to vulnerable households and facilities to enhance their resiliency in the face of wildfire risks and related de-energization events.

- CPUC D.21-12-031 allocated almost $67 million of unused accumulated funds to fund the waitlists of impacted budget categories in the respective SGIP Program Administrator service territories. Priority was given to Equity Resiliency

Budget projects.

- Qualifying technologies include wind turbines, waste heat to power technologies, pressure reduction turbines, internal combustion engines, microturbines, gas turbines, fuel cells 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 net energy metering (NEM) tariffs and net billing tariff (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 intra-rate class 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 reduced 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).[68]

Pursuant to AB 327 (2013), in January 2016, the CPUC approved Decision (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.[69] They also take service on a time-of-use rate plan. In its 2016 decision, the CPUC stated its intention to later revisit the NEM successor tariff.

In 2019, the CPUC commissioned an independent evaluation of NEM 2.0.[70] The evaluation found that the tariff is cost-effective for NEM 2.0 participants, but not cost-effective for non-participating ratepayers.[71] The study also found that after NEM 2.0 system installation, the average residential customer-generator pays much less than the estimated cost to serve them.[72] In August 2020, the CPUC opened Rulemaking (R.) 20-08-020 to revisit the NEM successor tariff.

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[68] See the evaluation of NEM 2.0 available at https://www.cpuc.ca.gov/nem2evaluation.

[69] 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.

[70] The draft and final reports are available at https://www.cpuc.ca.gov/nem2evaluation.

[71] The draft report found that NEM 2.0 is cost-effective from a combined participant/utility perspective due to a modeling error, but we report the final report's findings above for clarity on the conclusions that should be taken away.

[72] 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.

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 NEM 2.0, thus improving the equity of the tariff and helping to facilitate the state's building electrification goals.

The NBT accomplishes this 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 or leasing solar paired with battery energy storage than by purchasing or leasing only solar. These tariff changes are increasing the percentage of solar installations paired with storage, which supports grid reliability.

In November 2023, the CPUC adopted another decision in this proceeding, D.23-12-068. This decision 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. Also, it 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 Public Utilities Code Section 769.2. The VNBT and aggregation subtariff are in effect for customers submitting interconnection applications after February 14, 2024.

Income-Qualified Programs

In addition to programs serving income-qualified customers and customers residing in DACs mentioned previously, the IOUs provide three ratepayer-funded energy assistance programs for income-qualified customers. The California Alternate Rates for Energy program (CARE) provides bill discounts off energy bills for income-qualified customers. The Family Electric Rate Assistance (FERA) program provides families of three or more, whose household income slightly exceeds the CARE income-eligibility maximum, with a discount on their electricity bill. The Energy Savings Assistance program (ESA) provides no-cost direct-install in-home weatherization services, energy efficiency measures, and energy education to help eligible income-qualified households conserve and reduce energy, reduce energy costs and improve their health, comfort, and safety. The new ESA Multifamily Energy Savings Program provides no-cost energy efficiency measures within tenant units, in common areas (e.g. hallways, lobbies), and for whole buildings (such as central heating and cooling systems) for deed restricted and qualifying market rate multifamily properties.

In 2023, the ESA program also launched deeper energy savings and building electrification pilot programs. The deeper energy savings pilot program seeks to achieve up to 50 percent energy savings per household. The building electrification pilots include programs to retrofit existing homes with electric heat pumps and heat pump water heaters, and incentives to housing developers for all-electric construction.

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 is funded by non-exempt customers (exempt customers include 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.

The CARE program was established in 1989 by Public Utilities Code Sections 739.1 and 739.2, which authorizes a 15 percent rate discount for income-qualified customers off their energy bills. In 2001, the minimum CARE rate discount was increased from 15 percent to 20 percent by CPUC D.01--06--010. However, due to a number of factors on how rate increases and new charges were allocated to customers, the effective discounts grew to over 40 percent for some CARE customers.

In October 2013, AB 327 (Perea, Chapter 61, Statutes of 2013) was passed requiring 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 remain at 32.5 percent for SCE. These reductions occurred gradually to prevent rate shock. The gas rate discount has remained at 20 percent.

In 2023, the program provided an estimated $2.2 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.[73] A 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 these customers though, the CARE program surcharge has long been a small percentage of their energy bill. For example, in 2022, the CARE surcharge on a non-CARE residential monthly electric bill ranged from 2.6 to 4.4 percent of the total bill, which translates to around $4 to $5 a month on average. Similarly for residential gas bills, the CARE surcharge on a non-CARE residential monthly gas bill was about 2 to 3 percent of the total bill, which equals around $1.50 a month.[74]

[73] Some customers are enrolled in more than one program, for example SCE for electricity and SoCalGas for natural gas. Source: 2023 Investor-Owned Utility ESA-CARE Monthly Reports, posted to Docket A.19-11-003.

[74] Source: 2022 Investor-Owned Utility ESA-CARE Annual Reports, posted to Docket A.19-11-003.

PG&E’s CARE subsidy in 2023 was approximately $998 million (electric and gas combined), compared to $710 million for SCE, $254 million for SDG&E (electric and gas combined), and $266 million for SoCalGas (see **Table 5.4**).

Table 5.4 2023 CARE Program Costs ($000)[75]

Utility	Operations	Subsidy	Administrative Costs	Total
PG&E	Electric	$805,137	$7,628	$812,765
	Gas	$192,849	$1,907	$194,756
SCE	Electric	$710,612	$7,063	$717,675
SDG&E	Electric	$223,862	$5,475	$229,337
	Gas	$30,193	$671	$30,863
SoCalGas	Gas	$266,305	$9,062	$275,368
Total		**$2,228,958**	**$31,806**	**$2,260,764**

Energy Savings Assistance Program (ESA)[76]

The ESA program is a no-cost 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 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 Senate Bill 756, the program expanded to a greater number of California low-income households at or below 250 percent of the Federal Poverty Guidelines.

The program’s original 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.

[75] Source: 2023 Investor-Owned Utility ESA-CARE Monthly Reports, posted to Docket A.19-11-003.
[76] Formerly known as the Low-Income Energy Efficiency (LIEE) Program.

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 Public Utilities Code Section 2790 requiring the 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 (Public Utilities 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 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 Multifamily sector, and pilots.

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.

In 2023, per Decision directive, the IOUs launched a new multifamily component within the ESA program – the Multifamily Energy Savings 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 Multifamily 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, per Decision directive, 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.

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 programs with similar criteria.[77] **Table 5.5** shows the 2023 ESA program costs. In 2023, ESA served nearly 132,000 households, achieved 36 GWh and 2.2 MMtherms of annual energy savings.[78] About 90 percent of the total ESA expenses goes towards the ESA Main program; this percentage may decline over time as the MFES and pilot programs ramp up and these program budgets are expended.

[77] 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)

[78] Final household treatment numbers will be available in IOU Annual Reports for Program Year 2022 on May 1, 2023.

Table 5.5: 2023 ESA Program Costs ($000) [79]

Utility	Operations	ESA Total Year-To-Date Expenses 2023 *	ESA Main Year-To-Date Expenses 2023
PG&E	Electric and Gas	$132,504	$119,882
SCE	Electric	$28,130	$23,354
SDG&E	Electric and Gas	$72,213	$67,177
SoCalGas	Gas	$17,007	$14,061
Total		**$249,854**	**$224,473**

*ESA Total expenses include the ESA Main program, pilots, administrative expenses, and other costs as outlined in the IOUs' monthly reports.

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. 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.

The income limits of the FERA program range from 200 percent plus $1 to 250 percent of the Federal Poverty Guidelines. Public Utilities 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.

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, Chapter 412, Statutes of 2018) and Public Utilities 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

[79] Source: 2022 Investor-Owned Utility ESA-CARE Monthly Reports, posted to Docket A.19-11-003.

eligibility for the ESA program as of July 2022 allows for some cross-program marketing and enrollment between ESA and FERA.

PG&E's FERA subsidy in 2023 was approximately $17.2 million, compared to $12.1 million for SCE, and $4.7 million for SDG&E. At the end of 2023, approximately 79,160 households were enrolled in FERA out of an estimated 430,450 eligible households.[80] IOUs did not meet the 50 percent enrollment goal by 2023 and are exploring ways to increase program enrollment and meet the 2026 enrollment goal. **Table 5.6** shows the 2023 FERA program costs.

Table 5.6: 2023 FERA Program Costs ($000)[81]

Utility	Operations	Subsidy	Administrative Costs	Total
PG&E	Electric	$17,148	$2,686	$19,834
SCE	Electric	$12,085	$476	$12,561
SDG&E	Electric	$4,670	$537	$5,207
Total		**$33,903**	**$3,699**	**$37,602**

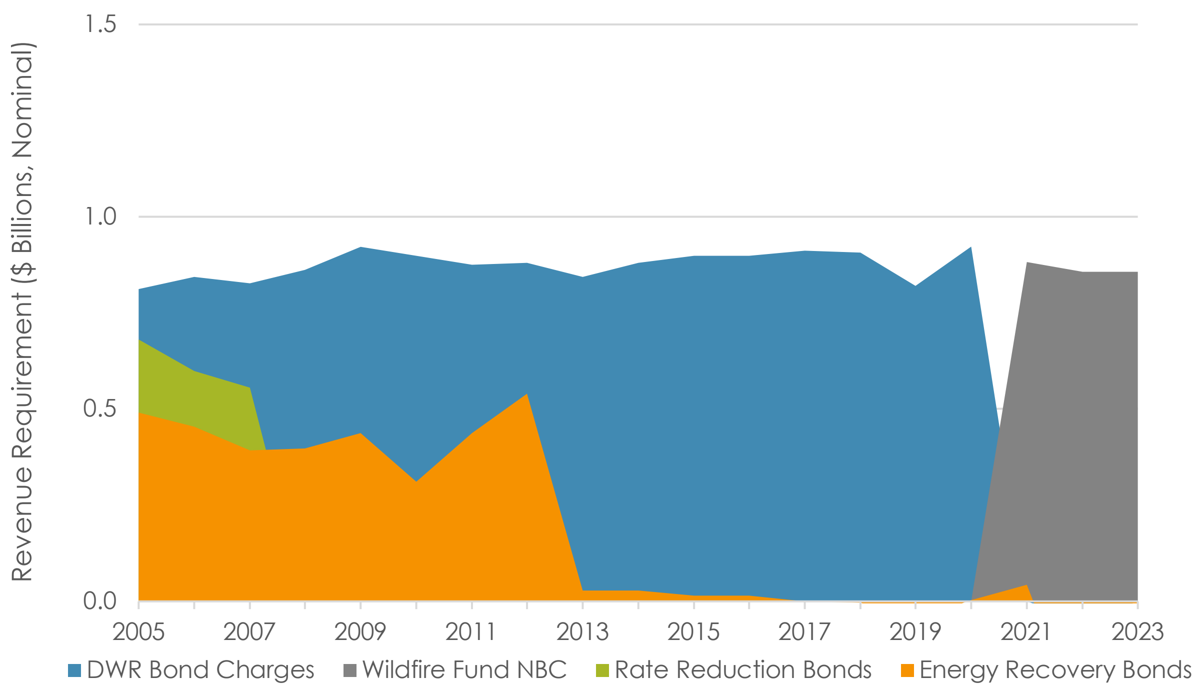
80 Source: 2023 Investor-Owned Utility ESA-CARE-FERA Monthly Reports, posted to Docket A.19-11-003. Final program costs will be available in IOU Annual Reports for Program Year 2023 on May 1, 2024.

81 Source: 2023 Investor-Owned Utility ESA-CARE-FERA Monthly 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)



Rate Reduction Bonds were issued in 1998 and paid back in full in 2007. AB 1890, the legislation that established the terms of energy restructuring, authorized these bonds to provide an immediate reduction in electric rates. Among other things, the legislation froze electric rates at June 1996 levels and reduced rates for residential and small commercial customers by 10 percent.

DWR bonds were issued in 2003 to recover the 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. The 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 (Holden, Chapter 79, Statutes of 2019) and CPUC Decision (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.[82] 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. The Wildfire Fund NBC supports the participation of large electrical utilities in the AB 1054 Wildfire Fund.

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 (PUC section 8386.3(e)). This program effectively saves ratepayers money by allowing lower cost financing compared to traditional utility financing mechanisms. The CPUC has thus far issued six financing orders under PUC Sec. 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 2023 appear in Table 6.1 under the category Other Regulatory.

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. The resulting AB 1054 bond charges for PG&E in 2023 appear in Table 6.1 under the category Other Regulatory. D.24-02-011

[82] CPUC D.19-10-056, October 24, 2019, available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M318/K549/318549782.pdf.

granted PG&E's request for a final recovery bond issuance under AB 1054 which should be completed in 2024. The related fixed recovery charges will be reported next year.

Table 6.1 shows the Bond Expenses and Other Regulatory components of the 2023 revenue requirement for each of the large electric IOUs.

Table 6.1: 2023 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	(56,973)	0	0	(56,973)
Wildfire Fund NBC	378,336	402,302	75,465	856,102
Other Regulatory	86,229	106,244	0	192,473
Total Net Amount	**407,592**	**508,546**	**75,465**	**991,603**

Fees

Fees include a variety of charges levied by federal, 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 2023 revenue requirement for regulatory fees. In total, this entire category of expenses accounted for roughly three percent of the 2023 revenue requirement. Some fees are included in the other revenue components. Only nuclear decommissioning costs are recovered separately through the Nuclear Decommissioning Adjustment Mechanism.

Table 6.2: 2023 Regulatory Fees ($000)

	PG&E	SCE	SDG&E	Total
Fees				
CPUC Reimbursement Fee[1]	104,842	100,183	0	205,025
Franchise Fee & Uncollectible Surcharge[2]	0	0	1,315	1,315
Catastrophic Events Memo Account	524,787	0	0	524,787
Hazardous Substance Mechanism	33,349	0	128	33,477
Nuclear Decommissioning[3]	170,381	2,771	37	173,189
Spent Nuclear Fuel	0	4,740	1,327	6,067
Major Emergency Balancing Account[4]	(10,377)	0	0	(10,377)
Wildfire Mitigation Plan Memo Account[5]	424	0	0	424
Fire Risk Mitigation Memo Account[6]	0	0	0	0
Total	**823,406**	**107,693**	**2,807**	**933,906**

1. 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 2023 electric CPUC reimbursement fees for PG&E, SCE, and SDG&E were $0.0013/kWh.
2. Not reported elsewhere.
3. Includes Nuclear Decommission franchise fees and uncollectible expense as applicable.
4. For SCE and SDG&E, forecasts for emergency preparedness and response are approved as part of the GRC budget and not in a segregated balancing account.
5. SDG&E has not collected revenue for Wildfire Mitigation Plan Memo Account.
6. SDG&E has not collected revenue for Fire Risk Mitigation Memo Account.

Definition of Fees

- **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.
- **Franchise Fees:** Fees paid by a privately-owned utility to cities and counties for the right to use or occupy public streets and roads, and for permission to provide service in their jurisdictions. These fees are then redistributed to the cities and counties. In some cases, these fees are included in other cost categories and not separately determined in this report, as appears to be the case with PG&E.[83]
- **Uncollectibles:** Includes accounts receivable that have defaulted or cannot be collected. There are large pending, uncollectible balances from COVID-19 related accounts that were not in rates in 2021. These will be partially offset with

[83] PG&E reported $0 for franchise fees in 2021 and in several other year's past, suggesting that they may have been reported in other cost categories after recovery in surcharges, and not recorded here.

California Arrearage Payment Program (CAPP) from the State and will be reported in next year's AB 67 Annual Report.

- **Catastrophic Events Memorandum Account (CEMA)**: An account established to enable a utility to recover the costs associated with the restoration of service and utility facilities affected by a catastrophic event (e.g., an earthquake) or state of emergency declared by federal or state authorities.
- **Hazardous Substance Mechanism:** An account established to allow certain costs of investigating and remediating hazardous waste sites identified by the utilities.
- **Nuclear Decommissioning:** Nuclear decommissioning funds are established for the safe removal of nuclear facilities from service and the reduction of residual radioactivity to a level that permits termination of the NRC license and release of the property for unrestricted use. Spent nuclear fuel is shown as a separate item.
- **Major Emergency Balancing Account:** Specific to PG&E, the MEBA recovers actual costs resulting from responding to major emergencies and catastrophic events not eligible for recovery through the CEMA. In some cases, costs relating to major emergencies that are found by the CPUC not to be eligible for recovery through the CEMA process may be recoverable through the MEBA.
- **Wildfire Mitigation Plan Memorandum Account:** In 2019, pursuant to SB 901 (2018), each electric utility opened an account to track its costs incurred to implement its annual wildfire mitigation plan and seek recovery at a later date. PG&E[84], SCE[85], and SDG&E[86] have submitted applications to recover the costs recorded in this account. WMP memorandum accounts have essentially been converted into balancing accounts for WMP-related activities since WMPs are recurring and not one-time expenses. This took place for each utility in its first general rate case after 2019.
- **Fire Risk Mitigation Memorandum Account:** In 2019, pursuant to SB 901 (2018), each electric utility was allowed to establish an account to enable it to track its costs incurred for fire risk mitigations, if any, that are not otherwise covered anywhere else, and seek recovery at a later date. The IOUs have requested to recover these costs in the same applications as their requests to recover Wildfire Mitigation Plan Memorandum Accounts discussed above.

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[84] In CPUC D.20-10-026 and D.23-07-017, PG&E was authorized to recover partial revenue for its Wildfire Mitigation Plan Memorandum Account costs recorded in 2019. In A.23-06-008 PG&E sought to recover 2020-2022 costs recorded in its Wildfire Mitigation Plan Memorandum Account. A decision is forthcoming in that proceeding.

[85] In CPUC D.21-01-012 and D.21-10-025, SCE was authorized to recover partial revenue for its Wildfire Mitigation Plan Memorandum Account costs recorded in 2019. In D.22-06-032 the Commission authorized partial recovery for Wildfire Mitigation Plan Memorandum Account costs recorded in 2020. SCE filed applications A.22-06-003 and A.23-10-001to recover Wildfire Mitigation Plan Memorandum Account costs recorded in 2021 and 2022, respectively.

86 In October 2023 SDG&E filed a Track 2 as part of its GRC A.22-05-016 to request recovery of costs booked between 2019-2022 in its Wildfire Mitigation Plan Memorandum Account.

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 2022 electric revenue requirement for the legislative mandates.

Table 6.3: 2023 California Mandated Programs Revenue Requirement ($000)

Program Name	Legislation	PG&E	SCE	SDG&E	Total
Aliso Canyon Energy Storage	AB 2514	0	9,076	0	**9,076**
Bioenergy Market Adjusting Tariff Non-Bypassable Charge	SB 860, SB 1122	4,655	1,125	0	**5,780**
California Energy Systems for 21st Century	SB 96	0	0	0	**0**
California Hub for Energy Efficiency Financing (CHEEF)	Cal. Public Utilities (Pub. Util.) Code § 454.5(b)(9)(C)	17,693	0	0	**17,693**
California Solar Initiative - Multifamily Affordable Solar Housing/Single-Family Affordable Solar Homes	SB 1, AB 217, AB 2723	0	0	0	**0**
Demand Response [87]	SB 73, SB 1414, AB 793 & AB 719	76,779	39,005	11,196	**126,980**
Department of Water Resources Bond	AB 1X and D. 01-03-081	0	0	0	**0**
Disadvantaged Communities - Single-Family Affordable Solar Homes, Green-Tariff, Community Solar Green Tariff	AB 327	35,346	7,539	1,735	**44,620**
Economic Development Rate Balancing Account (EDRBA)	Public Utilities Code § 740.4(a) and 740.4(c)	0	0	332	**332**

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

Program Name	Legislation	PG&E	SCE	SDG&E	Total
Electric Program Investment Charge/New Solar Homes Partnership Program	Public Utilities Code § 399.8, SB 1, SB 32, SB 350 & SB 854, AB X1 15, AB 66, AB 523, AB 802, AB 1890, AB 2140, AB 2218	96,716	76,885	16,280	**189,881**
Energy Efficiency	SB 350, AB 1330, AB 802, AB 32, AB 1890, AB 841	267,556	405,006	132,302	**804,864**
Energy Savings Assistance Program/California Alternate Rates for Energy Program Administrative Expense	Public Utilities Code § 2790, § 382, SB 580, SB 691, AB 327, AB 793, AB 2140, AB 2857	23,285	15,717	10,317	**49,320**
Family Electric Rate Assistance Administrative Expense	SB 987, SB 1135	2,686	476	537	**3,699**
Green Tariff Shared Renewables	SB 43	0	0	0	**0**
Greenhouse Gas Cost[88]	AB 32 (SB 43, SB 854, AB 57)	104,066	457,376	45,261	**606,703**
Greenhouse Gas Revenue Return	AB 32 (SB 43 & AB 57)	(491,405)	(773,198)	(182,489)	**(1,447,092)**
Grid Safety and Resiliency Program	AB 1054	0	0	0	**0**
Hazardous Substance Memorandum Account	AB X1 6	33,349	2,202	128	**35,679**
Mobile Home Park Program	Public Utilities Code § 2791-2799	24,625	14,301	18,198	**57,124**
Net Energy Metering[89]	AB 1070	0	0	0	**0**
New Home Energy Storage Pilot	AB 2514, AB 2868	0	5,056	0	**5,056**
New Solar Homes Partnership Program	SB 1, AB X1 14, AB X1 15	0	0	0	**0**
Officer Compensation	SB 901	0	0	0	**0**

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

89 Net Energy Metering includes solar system contracts and disclosures, as applicable.

Program Name	Legislation	PG&E	SCE	SDG&E	Total
Renewable Portfolio Standard[90]	AB 32, SB 1078, SB 350, SB 100	1,940,325	2,437,778	570,318	**4,948,421**
Residential Uncollectible Balancing Account (RUBA)	SB 598	0	0	6,700	**6,700**
San Diego Unified Port District	AB 628	0	0	(985)	**(985)**
San Joaquin Valley Disadvantaged Communities Pilot and Data Gathering	AB 2672	0	0	0	**0**
School Energy Efficiency Stimulus Program	AB 841	56,080	75,509	18,884	**150,473**
Self-Generation Incentive Program	SB 700, AB 970, AB 1144	59,895	56,626	20,069	**136,590**
Smart Grid	SB 17, AB 32	882	0	0	**882**
Solar on Multifamily Affordable Housing	SB 92AB 693	42,667	47,048	15,130	**104,845**
Statewide Marketing Program	AB 793, SB 350	0	0	0	**0**
Summer Reliability OIR	July 31, 2021 Proclamation of Emergency from Governor Newsom	49,358	0	0	**49,358**
Total Rate Adjustment Component	AB 1X	0	0	1,000	**1,000**
Transportation Electrification Programs[91]	SB 350, AB 1082, AB 1083, AB 628	(25,410)	45,932	44,832	**65,354**
Tree Mortality Non-Bypassable Charge	SB 43, SB 859	4,052	(50,043)	18,725	**(27,266)**
Wildfire and Natural Disaster Resiliency Rebuild (WNDRR)	SB 1477	1,143	0	300	**1,443**
Wildfire Fund Non-Bypassable Charge	AB 1054, AB 1X	378,336	402,302	75,465	**856,103**
Wildfire Hardening Fixed Recovery Charge	AB 1054	142,939	0	0	**142,939**
Total		**2,845,617**	**3,350,568**	**824,234**	**7,020,421**

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

[91] Transportation Electrification includes pilots, as applicable.

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 a sharing incentive under which utilities receive a reward if they procure gas at costs below certain benchmarks and incur a penalty if procured at costs above the benchmarks. The mechanism provides utilities with a financial incentive to purchase gas for core ratepayers at costs that are beneficial to the utility, with part of the savings being shared with ratepayers. Procurement costs shown in this report pertain to these core customers. Large volume noncore customers, such as industrial or electric generation, procure their own gas supplies and, therefore, procurement costs of their gas usage are not included herein. Core gas procurement costs are recovered in utility gas procurement rates, which are adjusted monthly. The commodity gas price is the cost component with the greatest variability. Monthly changes in gas commodity prices on customer bills provide consumers with price signals that they can use to adjust their gas usage. The tables below show costs for 2023 and a comparison of 2023 to prior years.

Table 7.1 shows the 2023 natural gas revenue requirement by components.

Table 7.1: 2023 Gas Revenue Requirement by Key Components ($000)

	PG&E	SDG&E	SoCalGas	Total
Core Procurement	986,787	474,126	3,408,039	4,868,952
Transportation	3,986,325	704,014	4,550,164	9,240,503
Public Purpose Programs	381,259	47,240	460,187	888,686
TOTAL	**5,354,371**	**1,225,380**	**8,418,390**	**14,998,141**

Table 7.2 shows historical revenue requirement for 2017-2023 for the key components.

Table 7.2: Historical Gas Utility Revenue Requirement ($000) (2017-2023)

	2017	2018	2019	2020	2021	2022	2023
Core Procurement	2,465,182	2,067,169	2,226,842	1,822,180	2,475,283	3,804,455	4,868,952
Transportation	6,275,397	6,458,407	7,418,647	7,869,039	8,264,942	8,964,845	9,240,503
Public Purpose Programs	647,260	604,622	650,968	575,600	630,382	715,570	888,686
Total	**9,387,839**	**9,130,198**	**10,296,457**	**10,266,819**	**11,370,607**	**13,484,870**	**14,998,141**

As **Table 7.2** shows, the 2023 total natural gas utility costs increased by 11.2 percent from 2022 compared to the 18.7 percent increase from 2021 to 2022.

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

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

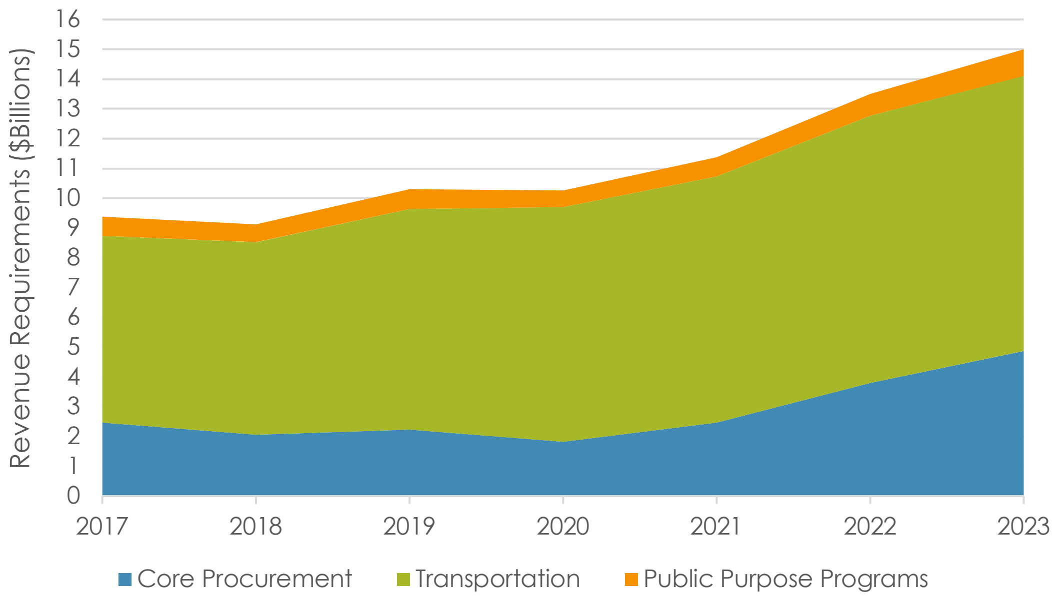


Table 7.3 shows the natural gas revenue requirement for each of the utilities from 2017-2023.

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

	2017	2018	2019	2020	2021	2022	2023
PG&E	4,610,816	4,470,985	4,587,569	4,484,635	4,926,879	5,655,409	5,354,371
SoCalGas	4,191,353	4,113,388	5,042,690	5,009,906	5,637,250	6,832,542	8,418,390
SDG&E	585,670	545,825	666,198	772,278	806,478	996,919	1,225,380
Total	**9,387,839**	**9,130,198**	**10,296,457**	**10,266,819**	**11,370,607**	**13,484,870**	**14,998,141**

From 2022 to 2023, revenue requirements decreased for PG&E but increased for SoCalGas and SDG&E. PG&E's revenue requirement decreased by 5.3 percent, while SoCalGas' and SDG&E's increased by 23.2 percent and 22.1 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 increased by 28 percent from 2022 to 2023. PG&E saw an 11.2 percent decrease in core procurement costs, while SoCalGas saw a 44.1 percent increase and SDG&E saw a 44.7 percent increase.

Total transportation and distribution costs increased by 3.1 percent from 2022 to 2023. PG&E's transportation costs decreased by 5.6 percent, while SoCalGas SDG&E saw a 10.5 percent increase and SDG&E saw a 12.9 percent increase.

A third component of costs is the natural gas PPP costs, which increased by 23 percent from 2022 to 2023. PPP costs include expenditures for CARE and low-income energy-efficiency programs, which are designed to subsidize low-income households' utility bills. PG&E and SoCalGas saw increases of 19 percent and 31.7 percent. SDG&E's PPP costs decreased by 10.3 percent.

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.

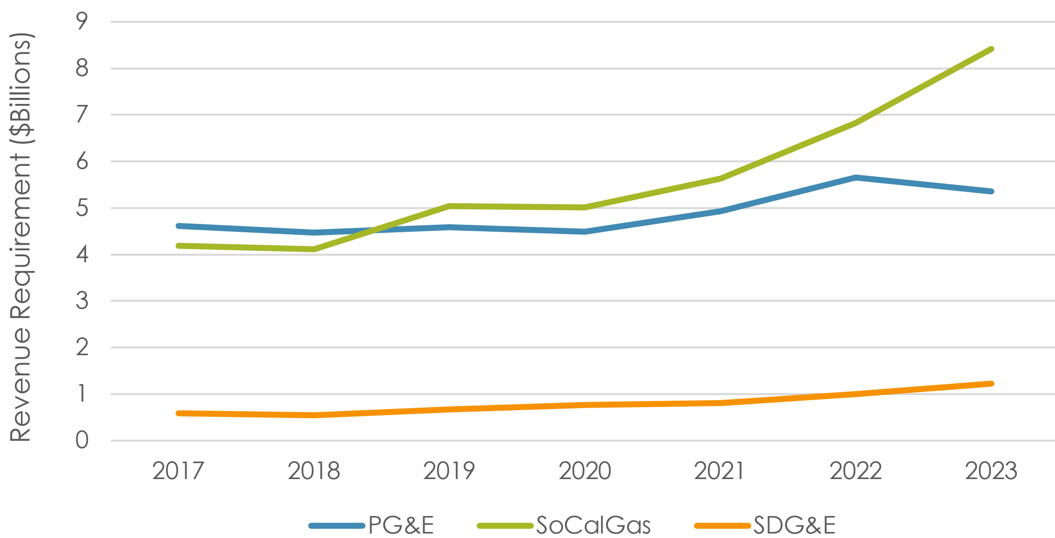
FERC possesses broad powers under NGA Section 4A, added by the Energy Policy Act of 2005 (EPAct), to investigate and penalize anticompetitive behavior of the interstate natural gas transmission under its jurisdiction. FERC's enforcement powers also encompass broad market investigations into events with 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, almost 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 2023-24.

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)



SoCalGas' average procurement rate to bundled core customers for the period January through March 2023 was $17.18/MMBtu,[92] compared to $6.67/MMBtu for the same period in 2022. In particular, SoCalGas' procurement rate in January 2023 was $34.49 per MMBtu, significantly higher than $10.53/MMBtu in December 2022 and $8.36/MMBtu in January 2022.

These elevated procurement costs resulted in a total core procurement increase of 28 percent across all three IOUs. This increase is lower than the increase of 53.7 percent experienced from 2021 to 2022.

Table 7.4 and **Figure 7.3** show the historical revenue requirement for natural gas core procurement.

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

Table 7.4: Historical Core Procurement Revenue Requirement ($000)

	2017	2018	2019	2020	2021	2022	2023
PG&E	1,158,601	879,270	935,782	770,337	865,924	1,110,950	986,787
SoCalGas	1,154,731	1,048,393	1,134,044	923,497	1,417,147	2,365,840	3,408,039
SDG&E	151,850	139,506	157,016	128,346	192,212	327,665	474,126
Total	**2,465,182**	**2,067,169**	**2,226,842**	**1,822,180**	**2,475,283**	**3,804,455**	**4,868,952**

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

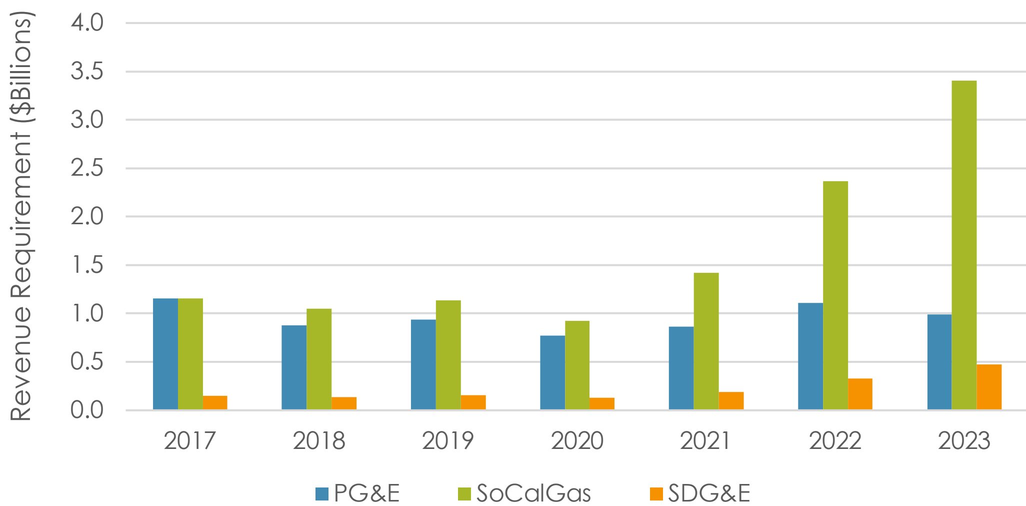

Table 7.5 shows the change in revenue requirement for core procurement.

Table 7.5: Percentage Change in Revenue Requirement for Core Procurement (2017-2023)

	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
PG&E	(24.1%)	6.4%	(17.7%)	12.4%	28.3%	(11.2%)
SoCalGas	(9.2%)	8.2%	(18.6%)	53.5%	66.9%	44.1%
SDG&E	(8.1%)	12.6%	(18.3%)	49.8%	70.5%	44.7%
Total	**(16.1%)**	**7.7%**	**(18.2%)**	**35.8%**	**53.7%**	**28%**

In 2023, core gas procurement costs accounted for 32.5 percent of total revenue requirement. **Table 7.5** shows an overcall core procurement increase for all three IOUs, with an aggregate increase of 28 percent. Like the previous year, the increase is driven largely by commodity costs. PG&E saw a decrease of 11.2 percent, while SoCalGas and SDG&E saw increases of 44.1 percent, and 44.7 percent, respectively.

The increase in aggregate core procurement cost across all three IOUs from 2022 to 2023 is notably lower than the increase seen from 2021 to 2022, in part due to lower procurement costs for PG&E. 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, Decision Authorizing Pacific Gas and Electric Company's 2019-2022 Revenue Requirement for Gas Transmission and Storage Service, 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 18.17 percent. For PG&E, core procurement costs decreased due to reduced gas sales forecast 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 7.72 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.

From 2017 to 2018, overall gas procurement costs decreased by 16.1 percent. This decrease was reflected in the large reduction in core procurement costs (24 percent) for PG&E in 2017-2018. Procurement costs decreased by smaller margins for SDG&E (8 percent) and SoCalGas (9 percent) due to constraints on the SoCalGas system.

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 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 7.6 shows historical revenue requirement for transportation for 2017-2023. 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"[93] category, have increased by 47.2 percent from 2017 to 2023. Over the same time period, transportation costs increased by 25.2 percent for PG&E, 68.9 percent for SoCalGas, and 77 percent for SDG&E.

Table 7.6: Historical Transportation Revenue Requirement ($000)

	2017	2018	2019	2020	2021	2022	2023
PG&E	3,184,277	3,343,689	3,389,751	3,531,809	3,783,288	4,224,068	3,986,325
SoCalGas	2,693,301	2,741,585	3,550,769	3,723,109	3,896,051	4,117,214	4,550,164
SDG&E	397,819	373,133	478,127	614,121	806,478	623,563	704,014
Total	**6,275,397**	**6,458,407**	**7,418,647**	**7,869,039**	**8,264,942**	**8,964,845**	**9,240,503**

Table 7.7 shows the change in revenue requirement for transportation.

Table 7.7: Percentage Change in Revenue Requirement for Transportation (2017-2023)

	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
PG&E	5.0%	1.4%	4.2%	7.1%	11.7%	(5.6%)
SoCalGas	1.8%	29.5%	4.9%	4.6%	5.7%	10.5%
SDG&E	(6.2%)	28.1%	28.4%	(4.6%)	6.5%	12.9%
Total	**2.9%**	**14.9%**	**6.1%**	**5.0%**	**8.5%**	**3.1%**

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

Transportation costs represented 61.6 percent of total utility gas costs in 2023. **Table 7.7** shows that aggregate gas transportation costs increased by 3.1 percent from 2022, driven by SoCalGas' and SDG&E's increases. PG&E's transportation costs decreased by 5.6 percent, while SoCalGas' and SDG&E's increased by 10.5 percent and 12.9 percent, respectively. 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.[94] 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.[95] SoCalGas saw increases in Distribution costs primarily due to 2023 approved revenue requirement per the 2019 Sempra General Rate Case[96] and an adjustment to SoCalGas' revenue requirement in accordance with the Internal Revenue Service Private Letter Ruling.[97] 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, 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

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[94] Approved in D.21-10-022 and AL 4529-G

[95] See PG&E's 2023 Annual Gas True-Up AL 4693-G

[96] D.19-09-051

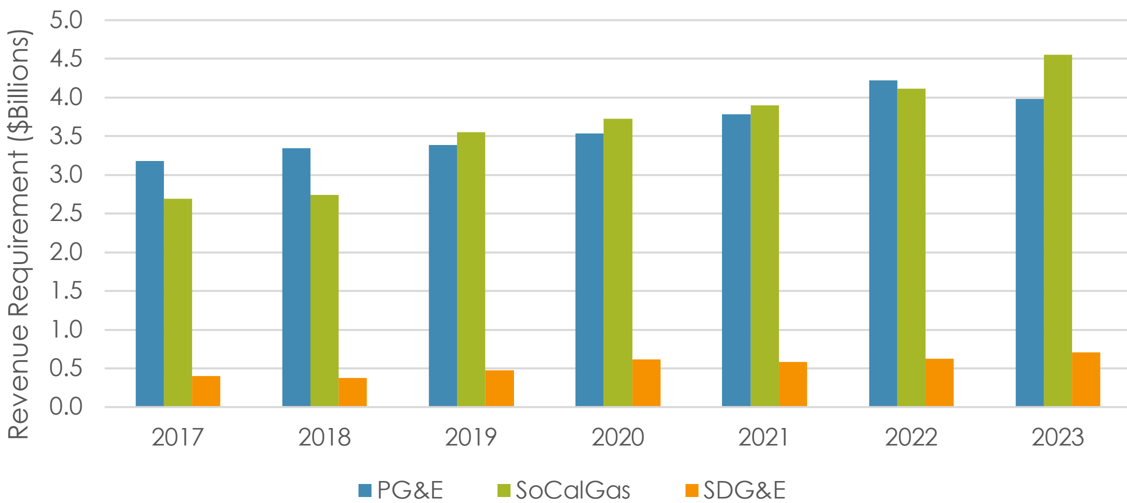
[97] SoCalGas AL 6018.

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 2019 total transportation costs 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 7.8 shows the 2023 revenue requirement for State-Mandated natural gas programs.

Table 7.8: 2023 State Mandated Programs Revenue Requirement ($000)

	PG&E	SoCalGas	SDG&E	Total
Self Generation Incentive Program (SGIP)	12,990	16,265	1,545	**30,800**
California Solar Initiative (CSI)	5,592	1,114	334	**7,040**
CPUC Fee[98]	15,130	N/A	N/A	**15,130**
Franchise Fee Surcharge (G-SUR)	12,721	57,777	4,981	**75,479**
Greenhouse Gas (GHG) Program	111,558	444,958	57,519	**614,035**
Energy Efficiency (EE) Programs	84,605	166,907	9,991	**261,503**
Low Income Energy Efficiency (LIFE)	83,931	80,174	10,316	**174,421**
Public Interest RD&D and State Board of Equalization (BOE) Administrative Fees	11,848	12,265	2,278	**26,391**
California Alternate Rates for Energy (CARE) Program	200,875	200,841	22,557	**424,273**
School Energy Efficiency Stimulus (SEES) Program	N/A	N/A	2,098	**2,098**
Total	**539,250**	**980,301**	**111,619**	**1,631,170**

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 investor-owned natural gas utilities 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 25 percent of their allocated allowances in 2015 and increasing at a rate of 5 percent per year through 2030 (when

[98] 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)

100 percent will be sold for ratepayer benefit). For 2023, natural gas utilities were required to sell 65 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. In D.23-02-014, the Commission advanced the return of the April 2023 electric and gas climate credits to February and March in order to help alleviate unexpectedly large customer gas bills resulting from unusually high natural gas prices.

In addition to customer credits, pursuant to SB 1477 (Stern, Chapter 378, Statutes of 2018), starting in Fiscal Year 2019-20, $50 million of allowance proceeds will be used for building decarbonization pilot projects each year through Fiscal Year 2022-23.[99] In addition, for 2022 and 2023, D.20-12-031 directs the collective gas IOUs to allocate $20M annually to incentivize in-state biomethane production.

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.[100] 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 investor-owned natural gas utilities now typically distribute the natural gas California Climate Credit annually in April, absent other direction from the Commission.

In 2021, the natural gas utilities collectively introduced approximately $901 million in GHG costs into rates and returned approximately $645 million in allowance proceeds to customers (see **Table 7.9**).

[99] Fiscal Year begins July 1. Funds for FY2019 were collected out of 2020 allowance proceeds, alongside FY2020 funding.

[100] 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 7.9: 2023 Greenhouse Gas Costs and Allowance Proceeds[101]

	2023 Natural Gas GHG Revenue Requirement	2023 Natural Gas Proceeds Distributed to Customers
PG&E	$398,315,713	($270,504,888)
SDG&E	$57,566,626	($48,983,757)
SoCalGas	$444,936,120	($325,061,169)
Total	**$900,818,459**	**($644,549,814)**

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 California Energy Commission. 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 23 percent from 2022 to 2023. These costs made up 5.9 percent of total revenue requirement in 2023. PG&E saw a 19 percent increase driven by increases in its Electric Efficiency portfolio budget[102] and CARE program[103]. SoCalGas saw a 31.7 percent increase primarily due to increases in its EE program[104] and LIEE programs[105]. SDG&E saw a 10.3 percent decrease primarily due to reductions in CARE program costs.

Gas PPP costs are recovered through the gas PPP surcharge on core and non-exempt noncore customers.[106] Only non-CARE customers pay for the CARE subsidy portion of the gas PPP surcharge. The gas PPP surcharges are changed annually through advice

[101] Revenue requirement and proceeds based on 2023 forecasted amounts. Proceeds excludes $84 million set aside for the SB1477/Building Initiative for Low-Emissions Development program and Technology and Equipment for Clean Heating program and biomethane incentives (D.20-12-031).

[102] See PG&E AL 4521-G-A and AL 6385-E-A. The increase in PG&E's EE budget request in 2023 relative to 2022 was mainly driven by third-party programs that were either ramping up or newly added to PG&E's EE portfolio in 2023. In addition, the Regional Energy Network (REN) and Community Choice Aggregator (CCA) EE portfolio administrators (PA) authorized budgets increased.

[103] The increase in the CARE program is driven by the CARE balancing account increase of $33 million. The CARE balancing account tracks the CARE discount given to low-income customers as well as the CARE administrative costs offset by the CARE revenues collected from Non-CARE customers.

[104] SoCalGas' Energy Efficiency Program increased by $59.8 million in 2023 due to higher funding for the program and a true-up adjustment. See SoCalGas AL 6052.

[105] As addressed Advice No. 5891, SoCalGas used its unspent and uncommitted funds from prior cycles to offset the authorized budget of $122 million for its LIEE program for 2022. For 2023, SoCalGas included the LIEE program funding as authorized in Decision 21-06-015.

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

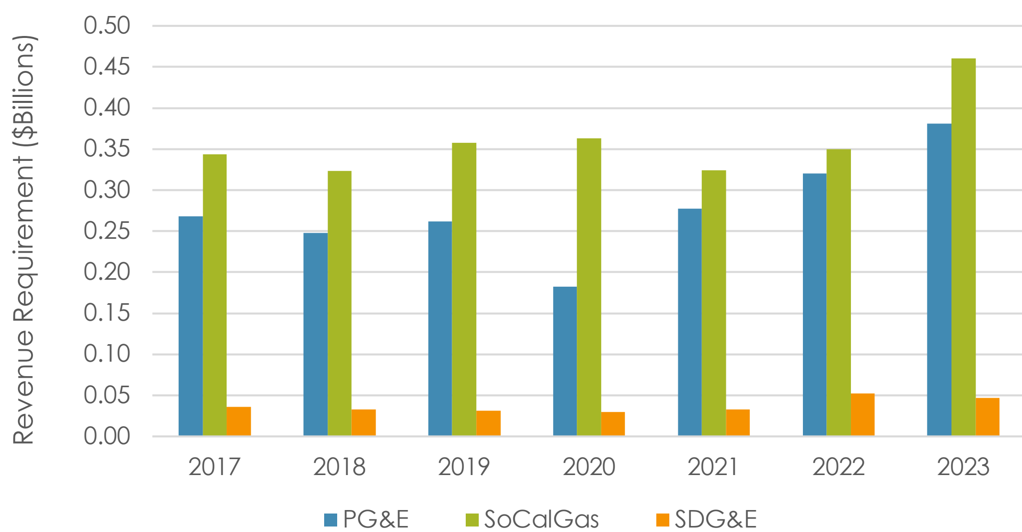
letter filings, incorporating the revenue requirements for the gas PPPs adopted in CPUC proceedings.

Table 7.10 and **Figure 7.5** show the historical revenue requirement for public purpose programs.

Table 7.10: Historical Public Purpose Programs Revenue Requirement ($000)

	2017	2018	2019	2020	2021	2022	2023
PG&E	267,938	248,026	262,036	182,489	277,667	320,391	381,259
SoCalGas	343,321	323,410	357,877	363,300	324,052	349,488	460,187
SDG&E	36,001	33,186	31,055	29,811	33,204	52,680	47,240
Total	**647,260**	**604,622**	**650,968**	**575,600**	**634,923**	**722,559**	**888,686**

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



Appendices

A digital copy of the appendices can be found at:

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

Appendix A: Historical Electric Revenue Requirements 2023-2018

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 399.8)			216,755	0	0
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**
Franchise Fee Surcharge**	PUC Sections 6350-6354, 6231	CPUC Decisions	**0**	**0**	**23,151**
Electric Total			**14,931,196**	**11,954,500**	**3,407,247**

*Recovered in distribution rate component

**Not reported elsewhere.

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**
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 Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**(135,009)**	**0**	**0**
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**
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
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**
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
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)**
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
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)**
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
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 2023-2018

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 & 740.8	CPUC Decisions	0	146,497	0
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 (CARE) Program	PUC Section 739.1		200,875	200,841	22,557
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 & 740.8	CPUC Decisions	0	136,377	0
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 (CARE) Program	PUC Section 739.1		171,727	229,388	27,340
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 & 740.8	CPUC Decisions	0	68,598	0
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 (CARE) Program	PUC 739.1		165,477	201,561	25,756
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 & 740.8	CPUC Decisions	0	38,678	0
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
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
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
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**