CALIFORNIA ELECTRIC AND GAS UTILITY COST REPORT

Public Utilities Code Section 913 Annual Report to the Governor and Legislature

California Public Utilities Commission
Energy Division

April, 2018

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I. Introduction

Enacted as Assembly Bill (AB) 67 in 2005, Public Utilities Code 913 requires the California Public Utilities Commission (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 also 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 report is submitted by the CPUC to fulfill these statutory requirements.

Background

The State of California has been a national leader in energy policy, setting innovative mandates for renewable energy, demand-side management, and greenhouse gas (GHG) emissions regulation. With the implementation of these policies, the utilities' cost structures and the rate setting process have become increasingly complex. The funds that each utility is authorized to collect in rates to meet its expenses — commonly referred to as revenue requirements — are approved through several different regulatory proceedings corresponding to various mandates.

The California Legislature passed AB 67 in 2005 to establish an annual reporting requirement that would identify the costs to ratepayers of all utility programs and activities currently recovered in retail rates. As in previous years, 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 2005.

The report presents an analysis of the CPUC-authorized revenue requirements for the four major California investor-owned utilities (IOUs or utilities): Pacific Gas and Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E) and

Southern California Gas Company (SoCalGas). Using sales forecasts, rates are set to collect these authorized revenue requirements. Any 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 ensures that the utilities only collect their authorized revenue requirements and that they recover their costs despite the effect of conservation and efficiency programs on sales.

Overview

Electric Utility Costs

- **Compared to 2016, the CPUC-authorized annual revenue requirement[1] for SCE and SDG&E increased by 4.3% and 8.4%, respectively. The annual revenue requirement for PG&E decreased by 2.9%.** The 2017 revenue requirement for the three electric utilities are shown in **Table 1.1**. The total company revenue requirement (including transmission)[2] for the electric utilities in 2017 is as follows: PG&E $14.2 billion, SCE $12.1 billion, and SDG&E $4.3 billion for a total of $30.6 billion.

Table 1.1: Electric Utility Revenue Requirement Comparison ($000)[3]

Utility	2017 CPUC	2016 CPUC	Difference ($000)	Difference %	2017 Transmission	2017 Total Company
PG&E	12,295,566	12,657,290	(361,725)	(2.9%)	1,936,457	14,232,023
SCE	11,067,265	10,606,894	460,371	4.3%	1,011,823	12,079,088
SDG&E	3,726,975	3,437,561	289,414	8.4%	582,004	4,308,979
Total	**27,089,806**	**26,701,746**	**388,060**	**1.5%**	**3,530,285**	**30,620,091**

Much of the decrease in PG&E's revenue requirement is due to lower distribution-related general rate case (GRC)[4] costs. The revenue requirements for SCE and SDG&E increased mainly due to a higher forecast for generation costs.

- **Power procurement costs increased for SCE and SDG&E since 2016.** 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 2017 revenue requirement for the three electric utilities associated with generating electricity.

[1] 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.

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

[3] SCE Advice Letter 3515-E-A, PG&E Advice Letter 4902-E-B, and SDG&E Advice Letter 3028-E, all effective 1/1/2017, as updated in responses to data requests with as-of dates of 7/7/2017, 7/1/2017, and 12/1/2017, respectively.

[4] See Chapter II for a discussion on general rate cases revenue requirements.

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

Utility	2017	2016	Difference	
			$000	%
PG&E	6,481,928	6,754,687	(272,759)	(4.0%)
SCE	5,569,248	4,544,421	1,024,827	22.6%
SDG&E	1,846,702	1,586,656	260,046	16.4%
Total	**13,897,878**	**12,885,764**	**1,012,115**	**7.9%**

Much of the decrease in PG&E's generation revenue requirement is due to lower forecasts for bilateral contracts coupled with decreased load. PG&E also saw a decrease in generation-related operations and maintenance (O&M) costs approved in the 2017 GRC. The increase in SCE's generation revenue requirement is due to increases in forecasted qualifying facilities contract costs and other procurement costs caused by amortization of prior revenue requirements. SDG&E saw increases in similar generation costs in 2017.

- **Electric distribution costs increased for SDG&E.** Distribution costs include the costs of providing service below a certain voltage (60 kV, 69 kV, and 200kV for PG&E, SDG&E, and SCE, respectively) that are regulated by the CPUC. **Table 1.3** shows the 2017 revenue requirement for the three electric utilities associated with distribution of energy through the electric grid.

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

Utility	2017	2016	Difference	
			$000	%
PG&E	4,686,415	4,833,503	(147,088)	(3.0%)
SCE	4,470,818	4,912,420	(441,602)	(9.0%)
SDG&E	1,580,510	1,499,889	80,621	5.4%
Total	**10,737,743**	**11,245,812**	**(508,069)**	**(4.5%)**

SCE's distribution revenue requirement was reduced mainly by lower O&M costs approved in the 2015 GRC and by environmental enhancement refunds. SDG&E's increase can be attributed to amortizations of balancing accounts and increases in other GRC expenses.

- **Electric transmission costs increased for PG&E and SDG&E since 2016.** Transmission costs include the costs of providing service above a certain voltage (60 kV, 69 kV, and 200kV for PG&E, SDG&E, and SCE, respectively) that are regulated by the Federal Energy Regulatory Commission (FERC). **Table 1.4** shows the 2017 revenue requirement for the three electric utilities associated with distribution of energy through the electric grid.

Table 1.4: Electric Transmission Revenue Requirement Comparison ($000)

Utility	2017	2016	Difference	
			$000	%
PG&E	1,936,457	1,558,681	377,777	24.2%
SCE	1,011,823	1,058,025	(46,202)	(4.4%)
SDG&E	582,004	531,095	50,909	9.6%
Total	**3,530,285**	**3,147,801**	**382,483**	**12.2%**

Much of the variation since 2016 in the transmission revenue requirement is due to transmission access charge (TAC) and transmission owner rate case revenue requirements.[5]

- **Energy Efficiency and Low-Income program costs increased for PG&E since 2016.** These public purpose programs (PPPs) involve rate discounts and energy efficiency improvements for low-income customers. **Table 1.5** shows the 2017 revenue requirement for the three electric utilities associated with PPPs.

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

Utility	2017	2016	Difference	
			$000	%
PG&E	594,980	569,986	24,994	4.4%
SCE	611,601	807,196	(195,595)	(24.2%)
SDG&E	218,688	260,087	(41,399)	(15.9%)
Total	**1,425,270**	**1,637,269**	**(211,999)**	**(12.9%)**

Much of the change in the PPP revenue requirement is due to the revenue adjustment mechanisms for the electric program investment charge (EPIC) and other PPPs, which collect or refund the difference between the authorized revenue requirement and recorded revenue. SCE over-collected these funds in 2016 which led to a reduction in collections in 2017. SDG&E similarly over-collected in the California Alternate Rates for Energy (CARE) program.

- **Bonds and Regulatory Fees (including nuclear decommissioning revenue requirements) have increased since 2016 except for SDG&E.** During the era of electric restructuring, the State and the utilities issued a series of bonds in order to amortize the costs of energy restructuring and the energy crisis of 2000-2001. 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 2017

[5] See the discussion in Chapter III on transmission revenue requirements for more information.

revenue requirements for the three electric utilities associated with bonds and nuclear decommissioning activities.

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

Utility	2017	2016	Difference	
			$000	%
PG&E	532,242	499,114	33,128	6.6%
SCE	415,597	342,856	72,741	21.2%
SDG&E	81,075	90,930	(9,855)	(10.8%)
Total	**1,028,915**	**932,901**	**96,014**	**10.3%**

Much of the variation in the revenue requirements for bonds and assorted fees is driven by nuclear decommissioning costs. Revenue requirements for DWR bond charges and energy recovery bonds have decreased since 2016.

- **The revenue requirement for PG&E and SDG&E was increased in 2017 due to adjustments for amortizations of balances in balancing and/or memorandum accounts whereas the revenue requirement for SCE decreased. Table 1.7** shows the effect of these adjustments on the revenue requirements for the electric utilities.

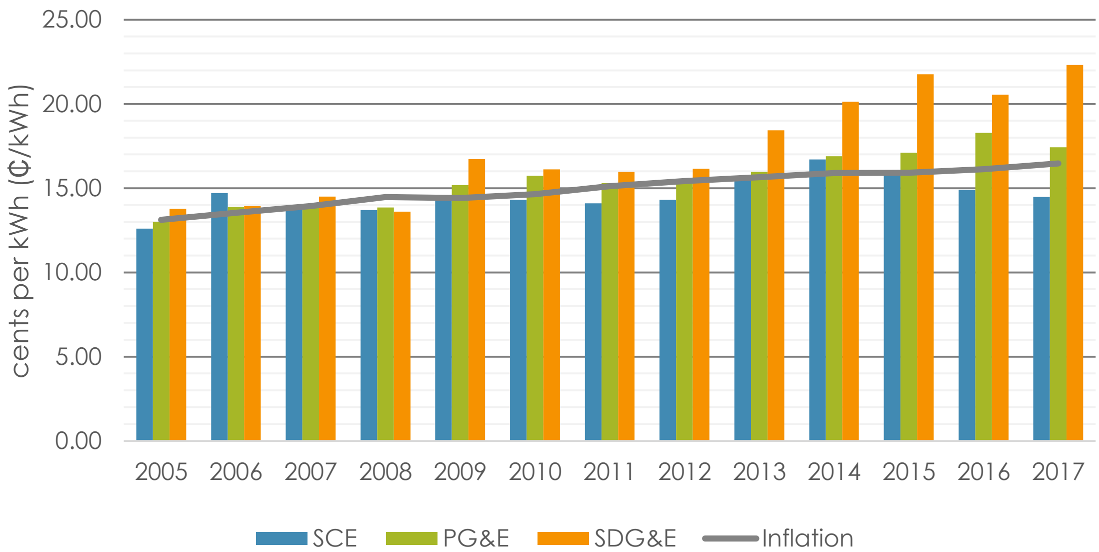
Table 1.7: Adjustments to the 2017 Revenue Requirement ($000)

Utility	Forecasted 2017 Costs	Amortization Adjustments	Authorized 2017 Revenue Requirement	Difference %
PG&E	12,071,249	224,316	12,295,566	1.9%
SCE	11,430,059	(362,794)	11,067,265	(3.2%)
SDG&E	3,396,293	330,682	3,726,975	9.7%
Total	**26,897,602**	**192,204**	**27,089,806**	**0.7%**

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 in order to show the annual cost to ratepayers.

- **System Average Rate (SAR) increases generally tracked inflation from 2005 through 2012. PG&E's and SDG&E's rates have been above the Consumer Price Index (CPI) since 2012, SCE's rates are now well below the inflation rate (Figure 1.1).** From 2013 to 2017, system average rates (SAR) across the three electric IOUs have increased at an annual average of approximately 2.0%, which is well above the average annual inflation rate of 1.3% over the same time period (**Table 1.8**), even though SCE and PG&E posted a decrease this year. In 2017, SCE's system average rate was 14.48¢/kWh, PG&E's was 17.42 ¢/kWh, and SDG&E's was 22.32 ¢/kWh. To show the effect of inflation from 2005 – 2017 for the purpose of comparison, the average SAR for the utilities in 2005 adjusted for inflation to 2017 nominal dollars is 16.47 ¢/kWh. The average 2017 SAR for the utilities is 18.07 ¢/kWh, which suggests that the cost of electricity to the ratepayer generally increased 1.60 ¢/kWh since 2005 when excluding the effects of inflation. The average rate of the utilities in 2005 adjusted for inflation to arrive at a 2017 CPI-adjusted average rate is 16.47 ¢/kWh.[6]

Figure 1.1: Trends in Electric System Average Rates (2005-2017)



Annual Inflation Rate (2005-2017)[7]													
2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2016	2016	2017	Average (2013-17)
3.4%	3.2%	2.8%	3.8%	-0.4%	1.6%	3.2%	2.1%	1.5%	1.6%	0.1%	1.3%	2.1%	**1.3%**

Table 1.8: Annual Change in Electric System Average Rates (2013-2017)

Utility	2013	2014		2015		2016		2017		Average
	Rate	Rate	% Change	Rate	% Change	Rate	% Change	Rate	% Change	% Change
SCE	15.46	16.70	8.0%	15.90	-4.8%	14.90	-6.3%	14.48	-2.8%	-1.5%
PG&E	15.96	16.90	5.9%	17.10	1.2%	18.28	6.9%	17.42	-4.7%	2.3%
SDG&E	18.43	20.12	9.2%	21.77	8.2%	20.54	-5.6%	22.32	8.7%	5.1%

- **SARs have been generally trending upward above inflationary adjustments in recent years for PG&E and SDG&E due to various factors.** For instance, in the case of SDG&E, increased costs of procuring power as well as a shortened cost-recovery period due to a delay in its 2012 GRC resulted in the cost increases reflected in the

[6] SCE Advice Letter 3515-E-A, PG&E Advice Letter 4902-E-B, and SDG&E Advice Letter 3028-E, all effective 1/1/2017, as updated in responses to data requests with as-of dates of 7/7/2017, 7/1/2017, and 12/1/2017, respectively.

[7] Source: Bureau of Labor Statistics, CPI-All Urban Consumers

SAR. All three utilities have experienced declines in kWh sales, which also lead to increased rates when revenue requirement remains flat or rises. Small incremental declines in SARs for PG&E and SCE in 2017 result from recent outcomes in GRCs, lower fuel costs, as well as the decommissioning of the San Onofre Nuclear Generating Station (SONGS) and refunds of the TAC.

- **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 80% of the utilities' electric rates**.**

Figure 1.2: 2017 Electric Rate Components

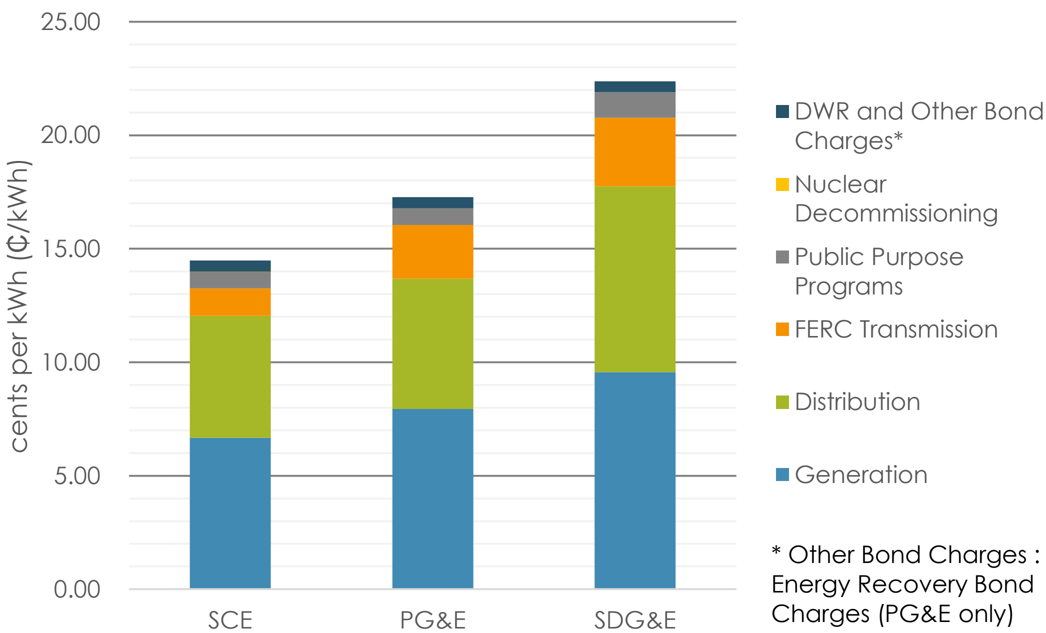


Table 1.9: 2017 Electric Rate Component Values (¢/kWh)[8]

Rate Component	SCE	PG&E	SDG&E
Generation	6.68	7.94	9.57
Distribution	5.36	5.74	8.19
FERC Transmission	1.21	2.37	3.01
Public Purpose Program	0.73	0.73	1.13
Nuclear Decommissioning	0.00	0.15	-0.05
DWR and Other Bond Charges	0.50	0.50	0.47
Total	**14.48**	**17.42**	**22.32**

<u>**Gas Utility Costs**</u>

- **For 2017, total natural gas utility costs decreased by 0.6% from 2016 compared to the 11.9% increase for 2015-2016 and the 0.2% increase from 2014 to 2015.** Please see Chapter VI for a discussion of gas utility costs.

The remainder of this report provides a breakdown of the various electric and gas revenue requirement components and identifies the sources of the greatest increases in costs. Chapters II - V address electric revenue requirements and Chapter VI addresses gas revenue requirements. In addition to the detailed summary tables provided throughout the text, Appendix A and Appendix B provide summaries of the IOU authorized revenue requirements organized by the rate components typically shown on customer bills.

[8] The negative value for the nuclear decommissioning rate component for SDG&E is associated with the overcollection of revenue based on a reasonableness review of balancing account expenditures in the last Nuclear Decommissioning Trust triennial review. These overcollections were returned to ratepayers in 2017.

II. Determining Revenue Requirements

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

1. **General Rate Cases (GRCs):** GRCs occur on a three-year cycle at the CPUC and evaluate the regulated operations of the IOUs as well as determine the reasonableness of their requests for increases in revenue requirement.
2. **Transmission rate cases at the Federal Energy Regulatory Commission (FERC):** The CPUC is required to allow recovery of all FERC authorized costs.
3. **Energy Resource Recovery Account (ERRA) proceedings**: The CPUC reviews each utility's fuel and power purchase forecast and, to the extent deemed reasonable, passes through the revenue requirements 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, or profit, only on costs that are utility-owned and capitalized (e.g. 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 or 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 do not typically pay generation costs but do pay transmission and distribution costs. In some cases, these customers are also required to pay non-bypassable charges for 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' 2017 revenue requirements.

Table 2.1: 2017 Electric IOU Authorized Revenue Requirements ($000)

Revenue Component	PG&E	SCE	SDG&E
Generation / Energy Procurement	6,481,928	5,569,248	1,846,702
Purchased Power	4,249,640	4,569,903	1,456,911
Utility Owned Generation	280,754	238,939	167,147
General Rate Case	1,948,890	605,317	289,538
Other Regulatory	2,643	155,090	-66,893
Distribution	4,686,415	4,470,818	1,580,510
Transmission	1,936,457	1,011,823	582,004
Public Purpose Programs	594,980	611,601	218,688
Bonds and Fees	532,242	415,597	81,075
Total 2017 Revenue Requirement	**14,232,023**	**12,079,088**	**4,308,979**

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 return on rate base (ROR) commonly expressed as a rate. This ROR is the main source of income for regulated utilities. Other things being equal, a larger rate base results in higher net income for the utilities.

Depreciation causes the utilities' rate base for existing assets to decline over time, while building new plants or making capital improvements to existing plants causes their rate base to increase. Changes in rate base also result in changes in the depreciation 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 2005 and 2017, the utilities' rate base more than doubled in size from $23.7 billion to $58.6 billion, or a 147% increase over the past decade, triggering corresponding increases in GRC revenue requirements.[9]

[9] When adjusted for inflation, the 2005 rate base corresponds to $29.7 billion, resulting in an approximately 97% increase in 2017 dollars.

Figure 2.1: Trends in Electric Utility Rate Base

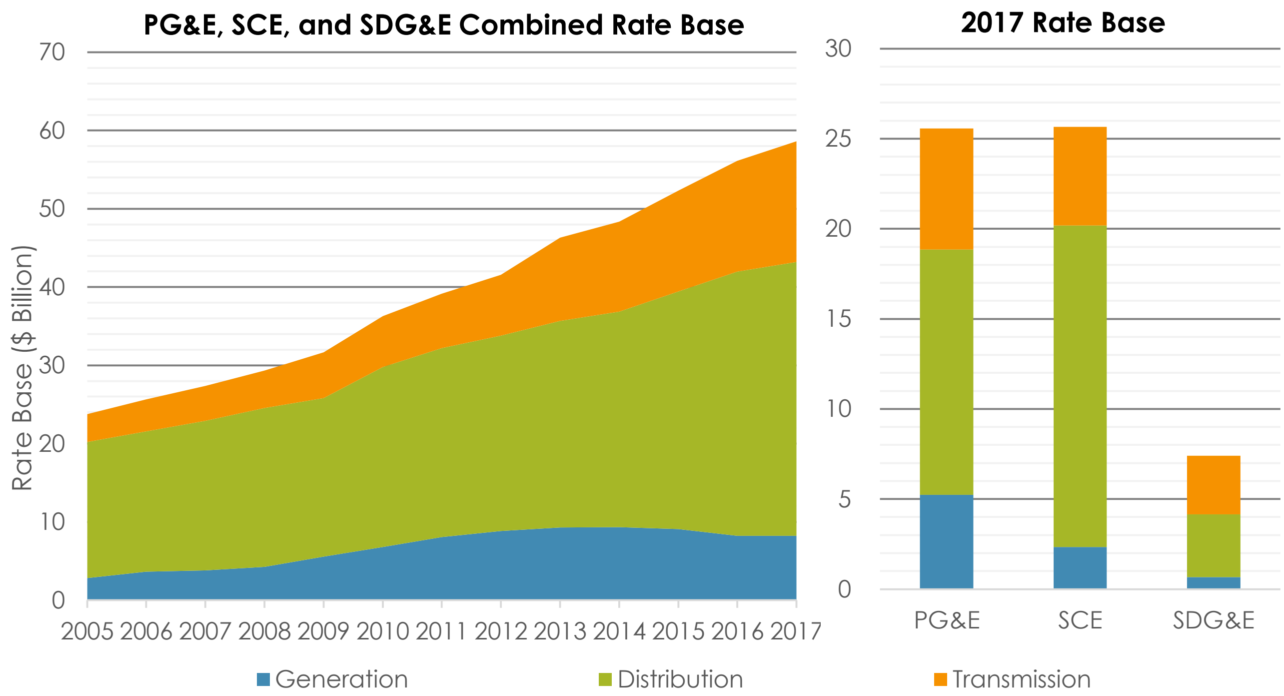


Table 2.2 shows the contributions of generation, transmission, and distribution components to the 2017 rate base.

Table 2.2: 2017 Utility Rate Base Components ($000)

Category	PG&E	SCE	SDG&E	Total
Generation	5,232,199	2,332,017	662,215	
Transmission	6,712,509	5,483,030	3,240,032	
Distribution	13,622,200	17,843,935	3,495,457	
Total All IOUs	**25,566,908**	**25,658,982**	**7,397,704**	**58,623,594**

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. These proceedings are usually on a three-year cycle for the major utilities, although this interval may be longer depending on the timing of the utility request or the scheduling needs of the CPUC. 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 Commission approval.

Approximately 55% of the utilities' electric revenue requirements are set in GRCs at the CPUC and the Federal Energy Regulatory Commission (FERC) (FERC sets the revenue requirement for transmission assets), while the remaining 45% consists of pass-through of the costs of power procurement, DWR power 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: Operations and Maintenance (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.

Table 3.1: 2017 General Rate Case Revenue Requirements ($000)[10]

	PG&E	SCE	SDG&E
Operation and Maintenance	2,925,764	1,503,403	665,017
Depreciation	1,610,151	1,575,482	393,186
Return on Ratebase	1,355,627	1,591,780	311,140
Taxes	774,355	602,410	205,145
Total	**6,665,896**	**5,273,075**	**1,574,488**

(Excludes FERC determined transmission revenue requirements)

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

- **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. While the utilities are required to maintain their systems in accordance with safety and reliability standards and industry best practices, the CPUC does not typically dictate how the utilities spend O&M funds. Depending on how the utilities manage various projects, they may spend more or less than the CPUC authorized O&M budget.

  In order 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 takes place in two new procedures: the filing of a Safety Model Assessment Proceeding (S-MAP) by each of the large energy utilities, and a subsequent Risk Assessment Mitigation Phase (RAMP).

  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. Each utility's RAMP proceeding utilizes the reporting format developed in its S-MAP proceeding, and describes how it 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. In the GRCs, 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 will incorporate the RAMP findings into the 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 provide the upfront financing for all capitalized expenditures, the CPUC authorizes a rate of return (ROR) on the invested capital. The ROR is the weighted average cost of debt and shareholder equity, and the CPUC allows a fair and reasonable return sufficient to allow the utilities to obtain financing. Formerly determined in each utility's GRC, the ROR is now determined 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.

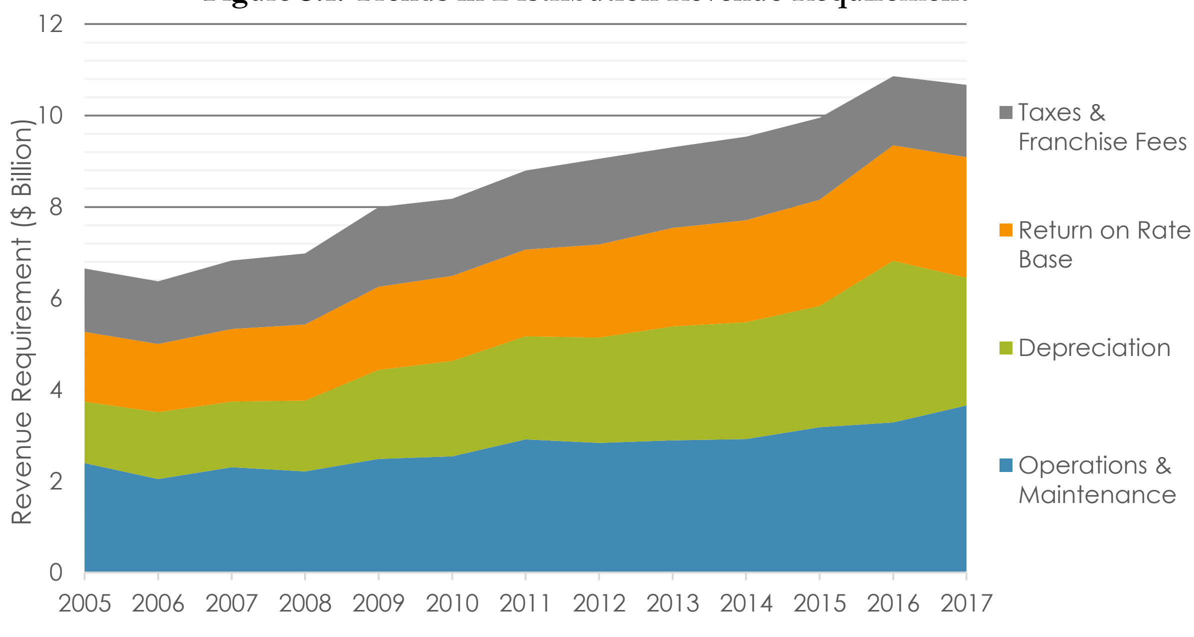
In addition to the authorized ROR, the CPUC has instituted incentive programs, such as the Efficiency Savings and Performance Incentive mechanism, whereby utility shareholders are eligible to receive payments for achieving good energy savings performance. The utilities do not earn a return on purchased 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. One-way balancing accounts are mainly used for spending related to safety such that the utility should not be able to profit from underspending in those areas.

Distribution Revenue Requirement

Since 2005, the total distribution revenue requirement has nearly doubled, from $5.3 billion to $10.7 billion (**Figure 3.1**).[11] Over the same time period, depreciation expenses have experienced the greatest increase, with an approximate 6.0% average annual growth rate.[12] The increases in distribution costs are primarily due to capital additions and ongoing infrastructure modernization and improvements to the distribution system, which have increased rate base, as discussed on page 9-10.

Figure 3.1: Trends in Distribution Revenue Requirement



[11] When adjusted for inflation, the 2005 total distribution revenue requirement corresponds to $6.6 billion, resulting in an approximately 62% increase in 2017 dollars.

[12] Adjusted for inflation.

Table 3.2 shows the contributions of distribution components to the 2017 revenue requirement.

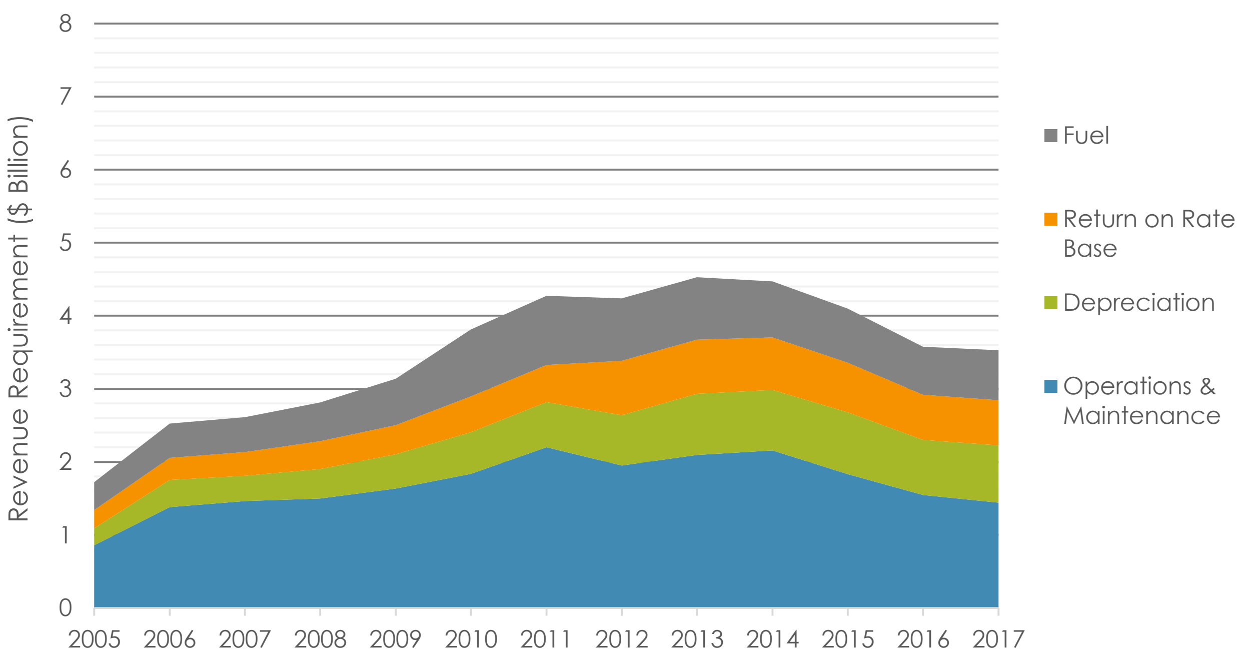
Table 3.2: 2017 Distribution Revenue Requirements ($000)

	PG&E	SCE	SDG&E
Operations and Maintenance	1,890,979	1,258,962	502,271
Depreciation	1,076,793	1,398,836	319,872
Return on Ratebase	974,879	1,407,551	257,662
Taxes and Franchise Fees	774,355	602,410	205,145
Total	**4,717,006**	**4,667,759**	**1,284,950**

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 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. As a result, the generation rate base tends to increase over time as shown in **Figure 3.2**.

Figure 3.2: Trends in Generation Revenue Requirement



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

Spikes in UOG revenue requirement in 2011 and 2013 were mainly the result of amortization of large under-collections recorded in the utilities' balancing accounts.

These accounts compare authorized generation revenue requirements to actual revenues collected through rates. Any amounts collected above or below authorized revenues are returned to, or collected from, ratepayers. The UOG revenue requirement decreased in 2015 and again in 2016 because costs related to the San Onofre Nuclear Generation Station owned by SCE and SDG&E have been categorized as regulatory costs.

Following electric industry restructuring in the late 1990s and the utilities' divestiture of fossil-fueled generation, UOG (including fuel costs) now accounts for 10% of their combined revenue requirements. The 2017 generation revenue requirement for the electric IOUs is shown in **Table 3.3**.

Table 3.3: 2017 Generation Revenue Requirements ($000)

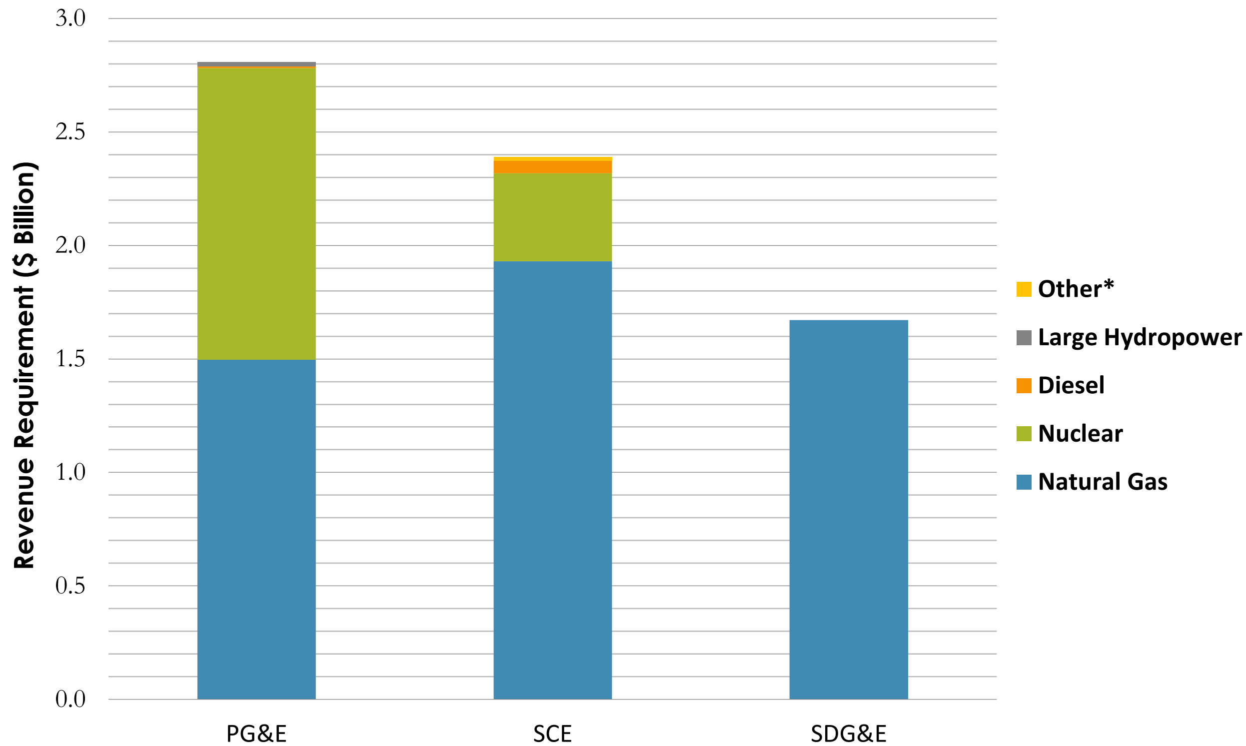
	PG&E	SCE	SDG&E
Operations and Maintenance	1,034,785	244,441	162,746
Depreciation	533,357	176,646	73,314
Return on Rate Base	380,748	184,229	53,478
Total	**1,948,890**	**605,317**	**289,538**

Figure 3.3 shows the components of the 2017 UOG revenue requirement by sources. PG&E's UOG consists primarily of hydro-electric, nuclear power (Diablo Canyon) and a number of natural gas plants (e.g., the 660 MW Colusa Generation Station, 580MW Gateway Generating Station, and 163 MW Humboldt Bay Generating Station). SCE's UOG portfolio consists primarily of nuclear (Palo Verde Nuclear Generating Station) and natural gas power plants, including the 1,035 MW Mountain View Power Plant and peaker plants. SCE no longer relies on coal since the Mohave Generating Station was taken out of service and SCE sold its share of the Four Corners plant.[13] 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.[14]

[13] The CPUC approved SCE's sale of its stake in the Four Corners plant in March 2012, and the sale was closed in December 2013.

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

Figure 3.3: 2017 Revenue Requirements of UOG Sources



*Other (SCE only) includes fuel cells and renewables

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 the Arizona Public Service.[15] 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 decided in a 2014 decision in the SONGS Investigation (OII), but are presently being reexamined to determine a fair and equitable balance between ratepayer and shareholder recovery.

PG&E owns and operates the Diablo Canyon Nuclear Power Plant. In January 2018, the Commission approved a joint request by PG&E and other parties to shutter the plant's two generators in 2024 and 2025.

[15] 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.

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:[16]

- Fees for disposal and storage of spent nuclear fuel are required by the US Department of Energy for temporary and permanent storage facilities.
- Nuclear decommissioning of generating plants at the end of their operating lives. To pay for these eventual decommissioning efforts, the utilities are required to establish decommissioning funds, whose amounts are estimated in triennial proceedings, and which are funded through rates during the operating lives of the nuclear plants.

Authorized Rate of Return

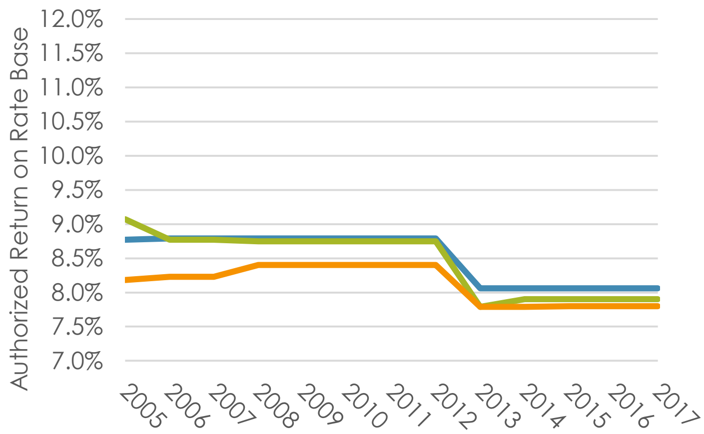
The authorized rate of return on rate base (ROR) is the weighted average of the cost of capital provided to fund company operations. The cost of capital consists of debt obligations and dividend payments and other company earnings to shareholders. The cost of debt is based on the portion of the utility's capital structure financed by long-term debt (maturation periods greater than one year) and the estimated debt interest rate. The return on equity (ROE) is based on the equity portion of the capital structure (preferred stock and common equity) and the estimated payments to shareholders. The ROE is a prospective calculation that considers the returns on investments in other industries having similar risks. The CPUC authorizes a structure to maintain reasonable credit ratings and to attract additional capital investment.

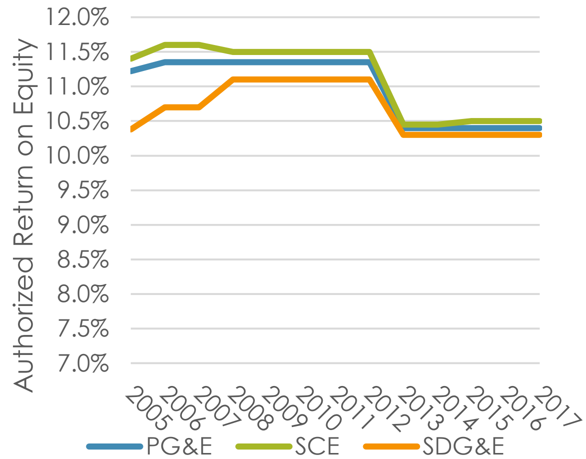
Figure 3.4 illustrates the ROR expressed as a rate authorized by the CPUC since 2005 for major energy utilities. The figure does not include ROR authorized by FERC for IOU transmission systems; it includes only the ROR authorized by the CPUC for UOG and distribution. **Figure 3.5** shows trends in the return on equity (ROE) component of ROR authorized by the CPUC since 2005.

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

Figure 3.4: Trends in Weighted Average Rate of Return (ROR)

Figure 3.5: Trends in Return on Equity (ROE)





The utilities are currently required to file a complete cost of capital application every three years, although this review cycle can be, and has sometimes been, extended. SCE, SDG&E and PG&E will file their next joint cost of capital application in 2019.

Transmission Revenue Requirement

Background and Jurisdictional Separation History

As part of energy restructuring, the California Independent System Operator (CAISO) was created and given operational control[17] over the utilities' high voltage transmission lines on January 1, 1998, and authority for determining transmission revenue requirements was transferred to FERC.[18] The transmission revenue requirements authorized by FERC include the same core components (O&M, depreciation, and return on rate base) as the general rate cases at the CPUC. However, typically transmission revenue requirements at FERC are determined through settlements and adopted as "black box" numbers without a breakdown of specific components. Therefore, the Commission does not have the same level of information for transmission costs that it does for generation and distribution costs. The CPUC is the constitutionally designated agency to represent the interests of California ratepayers in utility Transmission Owner (TO) rate cases at FERC proceedings, where utilities request changes in their transmission revenue requirements.

Each utility defines its high voltage transmission lines differently. PG&E, SDG&E and SCE respectively define all power lines at and above 60kV, 69kV and 200kV as transmission-

[17] The Restructuring Decision (1996) functionally created the implementation of the CAISO through the acceptance of AB1890 (Sept. 24, 1996).

[18] 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).

level assets that are regulated by the FERC. All other electric power lines and assets remain under CPUC regulatory control and jurisdiction.

Transmission Revenue Requirements and Trends

The fundamental basis of the CPUC's advocacy role in FERC proceedings is one of containing ratepayer costs in the Transmission Owner (TO) rate case decision-making process.[19] To this end, the CPUC actively participates in TO rate cases before FERC to advocate for just and reasonable rates in wholesale electric market proceedings. Due to the importance and complexity of these rate cases, CPUC Legal and Energy Division staff examine a multitude of cost of service and capitalization issues for Trends in Transmission Revenue Requirements adequacy, cost effectiveness, safety, and prudence.

FERC determines the appropriate amount of transmission revenue requirement for the Investor Owned Utilities (IOUs).[20] When the IOUs file their transmission revenue requirement requests, the CPUC team, other joint interveners and FERC staff review, analyze and critique the filings while also conducting discovery on the utilities' filings to collect evidence and develop a fact-based recommendation on *fair and reasonable* revenue requirement to protect ratepayers. Generally, a FERC Administrative Law Judge facilitates a settlement, unless an impasse in the settlement process necessitates litigation.

In 2017, CPUC's representation in electric FERC-related work consisted of TO rate cases for the electric IOUs and merchant transmission owners. In the aggregate, FERC ordered a reduction totaling $200.86 million[21] for 2016 to the cost recovery requests filed by the IOUs in these rate cases. The results of cost reductions for 2017 are incomplete because a major transmission rate case was not resolved and is currently in litigation proceedings. These savings are reflected in lower rate increases of electricity charges for ratepayers. Thus far, CPUC representation in FERC rate cases from 2007-2017 has resulted in a cumulative savings of over $1.508 billion for ratepayers.

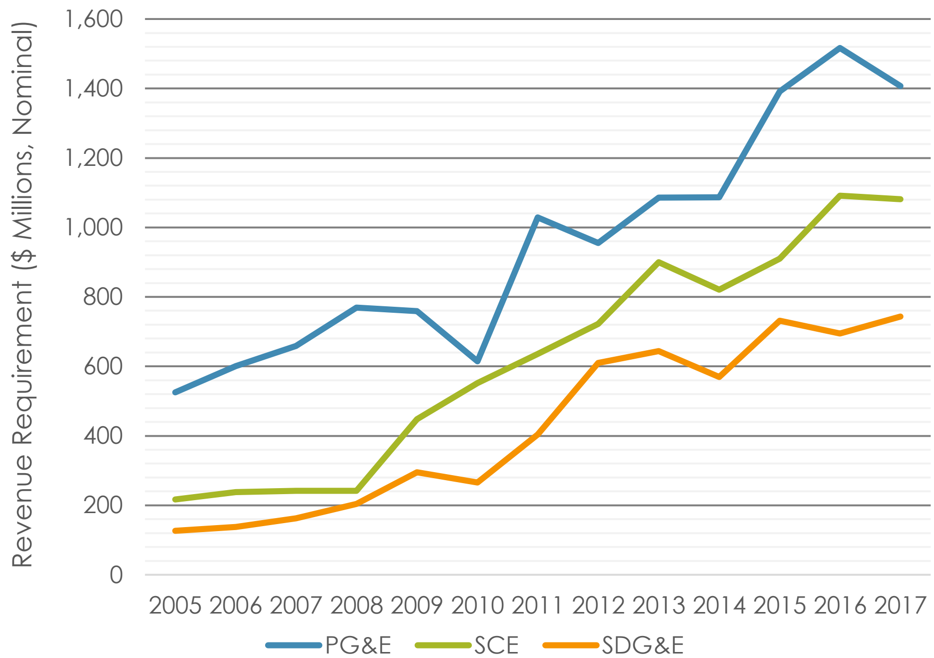
Transmission revenue requirements for the electric IOUs have been trending sharply up since 2003. Historically, much of the increase in the revenue requirements is due to additional transmission plant capital additions. Recently, these increases are driven primarily by CAISO reliability and RPS mandates, such as replacing and modernizing aging transmission infrastructure, interconnecting new electric generation to the electric grid, and compliance with updated North American Electric Reliability Corporation (NERC) requirements. From 2007-2017, PG&E's filed transmission revenue requirement has increased at a 10.52% annual average rate; SCE's at a 15.63% annual average rate; and SDG&E's at a 16.65% annual average rate as shown in **Figure 3.6**.

[19] The CPUC has a statutory duty to represent the interests of California electric and gas consumers before the FERC (CPUC Code, Section 307(b)).

[20] Although the CPUC generally has jurisdiction over the environmental review and citing of transmission projects, the FERC determines the revenue requirement of projects approved by the CPUC.

[21] Revenue requirement reductions for the PG&E TO17 case were $184.0 million (October, 2016); SDG&E TO4 C3 case were $16.66 million (August, 2016); and NextEra LLC TO1 case were $0.20 million (October, 2016).

Figure 3.6: Trends in Transmission Revenue Requirement[22]



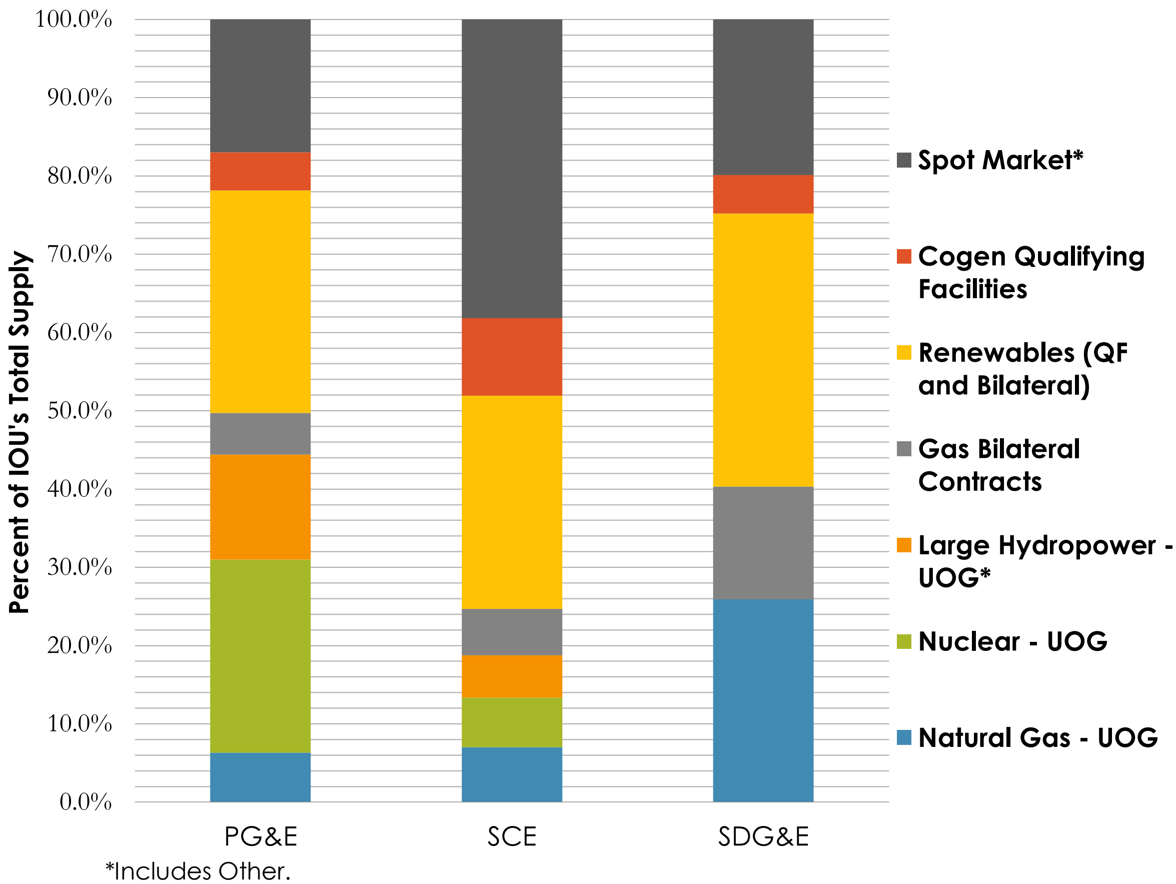
[22] Does not include costs related to Reliability Services or Transmission Access Charge.

IV. Power Procurement Costs

The generation revenue requirement includes utility owned (or retained) generation (UOG) costs (as discussed in Chapter II), 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 2017, purchased power accounted for 93% of the total generation revenue requirement, while UOG comprised about 7% (see **Figure 4.1**). Power purchase costs represent the largest component of forecasted generation costs and accounted for 34% of total revenue requirements. Recovery of these pass-through costs is authorized through the energy resource recovery account (ERRA) proceedings. There is no mark-up or profit for the utilities on purchased power expenses.

Figure 4.1: 2017 Forecast Energy Supply Costs for Electric Utilities



Background

Heavy reliance on power purchases rather than utility owned power plants 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% 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 June 1996 levels) 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 Department of Water Resources (DWR) to enter into power purchase contracts to stabilize the 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 integrating renewable resources into long term planning. The contracts resulting from these solicitations are reviewed by Procurement Review Groups 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% 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 Renewable Portfolio Standard (RPS) and required the utilities to procure 20% of their electricity demand from renewable resources by 2010. The statute also required each IOU to hold an annual solicitation to procure renewable power. SB 2 (2011) raised the RPS obligation to 33% by 2020. SB 350 (2015) again raised the RPS obligation to 50% by 2030.

Types of Purchased Power

DWR Contracts

DWR contracts were long-term contracts that the Department of Water Resources entered into on behalf of IOU customers during the energy crisis. Each year, DWR submits its revenue requirement to the CPUC for adoption and subsequent collection from ratepayers through the DWR Power Charge. The total energy provided by DWR has been declining since 2003 as contracts expire. Due to the expiration and/or novation of these contracts, DWR's revenue requirement for all three utilities was either negative or zero in 2017 and resulted in a refund of operating reserves to PG&E, SCE and SDG&E customers. As discussed further below, there is also a DWR bond charge that is collected separately in electric rates.

Qualifying Facilities (QFs)

Qualifying Facilities (QFs) are co-generation and renewable generation facilities that qualify to sell power to the utilities under the Federal Public Utility Regulatory Policies Act (PURPA). These facilities must meet FERC's requirements for ownership, size and efficiency to qualify as QFs. PURPA requires IOUs to interconnect with and purchase power from QFs at rates that reflect costs the utility avoids by buying QF power instead of procuring power from other sources. In 2011, the CPUC approved the QF/Combined Heat and Power (CHP) Program Settlement which suspends the "must take" obligation for QFs over 20 MW and establishes new energy prices for QFs.[23] In 2015, the CPUC adopted an Emissions Reduction Target associated with CHP procurement of 2.72 million metric tons of GHG Emissions Reductions by 2020.[24]

Figure 4.2 and **Figure 4.3** break out QF supply and revenue requirements for cogeneration and renewable energy. Since 2005 the total energy supply provided by all QFs, cogeneration and renewable has decreased as older contracts expire, and the QF revenue requirement has decreased by approximately $1.56 billion.

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

[24] D. 15-06-028

Figure 4.2: Trends in Purchased Power Supply (GWh)

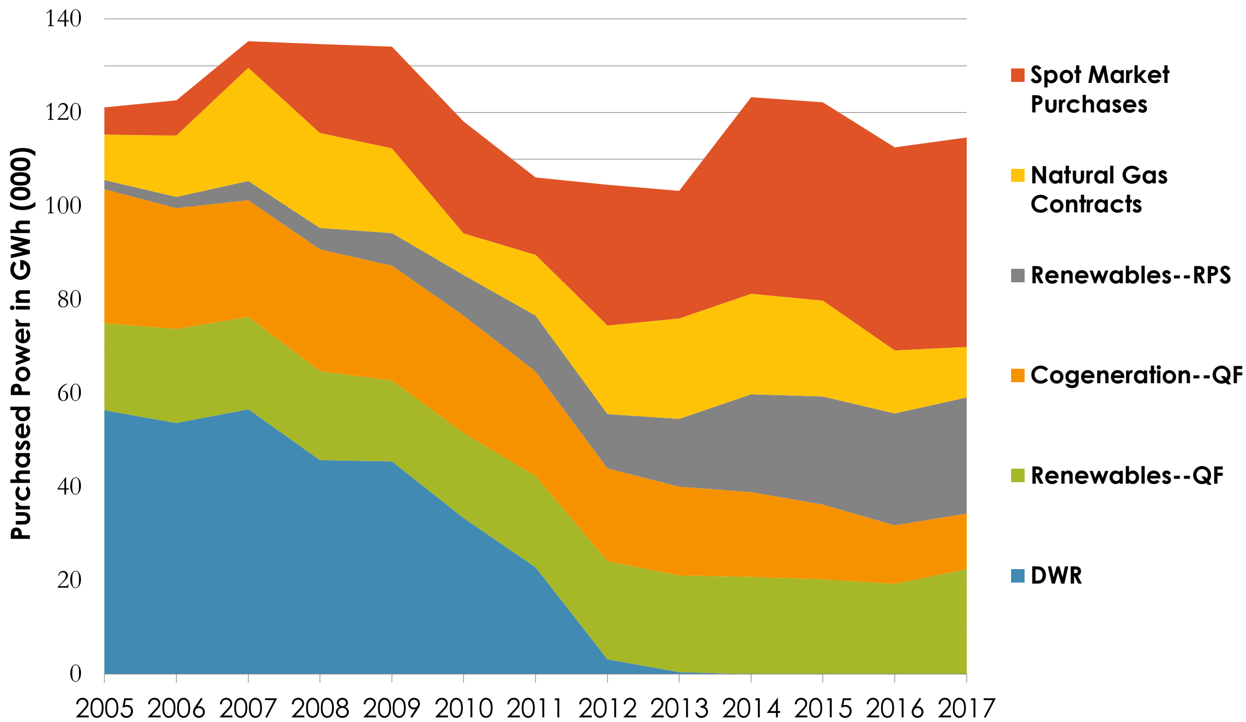
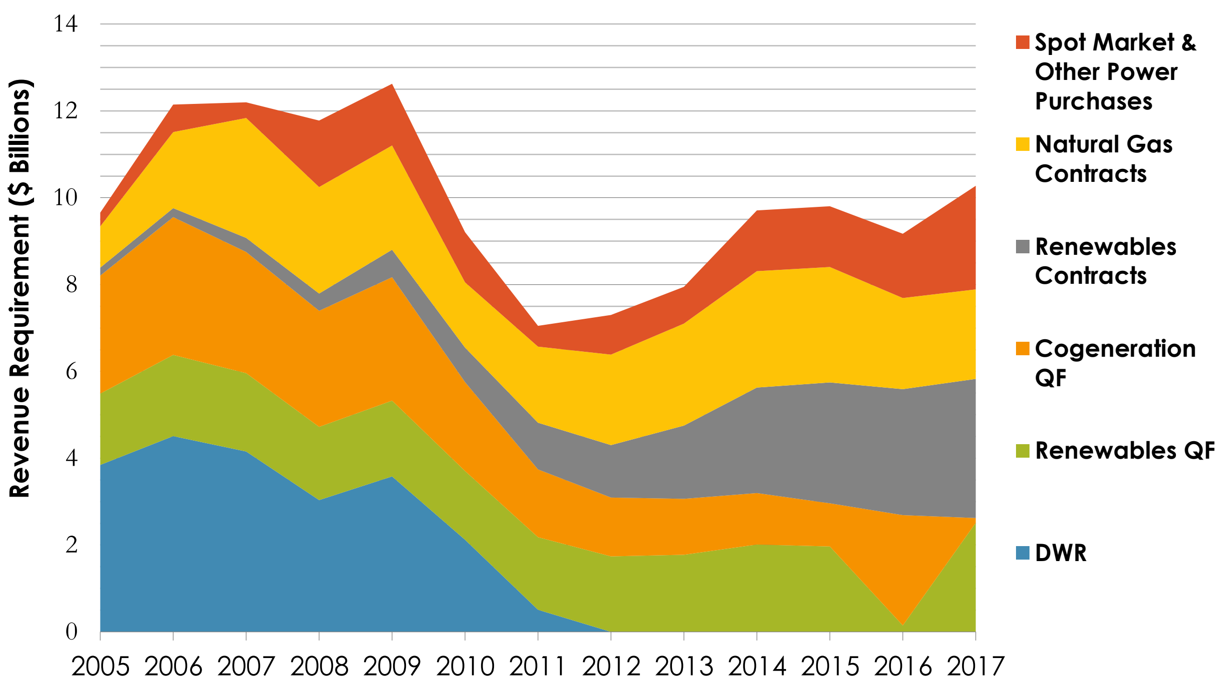


Figure 4.3: Trends in Purchased Power Revenue Requirement



Bilateral Contracts and Capacity Contracts

Bilateral contracts are a standard method for new energy procurement. These contracts are entered into directly between the utility and an independent power supplier, which may be a generator or a trader. The utilities typically select new contracts through a Request for Offers (RFO) open solicitation process. These bilateral contracts include capacity contracts, which are necessary for the utilities to maintain a minimum 15-17% planning reserve margin for generating capacity. Capacity contracts pay generators to be available to produce power and ensure that sufficient capacity is available to meet load. Reserve margins in excess of forecasts are necessary to address unplanned outages or unexpected increases in peak loads.

Bilateral contracts represent a larger portion of the utility power procurement portfolio as the utilities replace expiring DWR contracts. Because they include both long-term and capacity contracts, bilateral contracts typically cost more than spot market purchases or short-term contracts. In comparison, under current market conditions with excess supply, spot and short term purchases are frequently less expensive because the supplier has an existing resource and is willing to sell at variable cost. With the lessons learned from the energy crisis, the CPUC and the Legislature have determined that the IOUs should not rely heavily on spot market purchases, and instead should have a more diversified portfolio. As a result, the CPUC requires long term resource planning and resource adequacy. The price of long term contracts can be thought of as a "hedging cost" or "hedging premium" over spot market prices to ensure certainty and stability of prices in the future. Since 2005, the revenue requirements from bilateral contracts have increased approximately 10.8% annually.[25]

There are a few factors that help to explain this trend. First, in 2004, CPUC Decisions 04-10-035 and 04-01-050 required load-serving entities to maintain a planning reserve margin of 15% above peak load for all months of the year. These requirements are primarily met through contracts with natural gas fueled generators. Because resources held in reserve are over and above expected load, they may operate infrequently, making them more expensive on a per kWh basis. Second, natural gas prices spiked in 2005 as a result of Hurricane Katrina and again in 2008, which increased the cost of the natural gas resources in those and subsequent years. However, natural gas prices have fallen considerably in recent years. Finally, many bilateral contracts are for new natural gas facilities, which are more expensive than the older, depreciated plants because of the up-front capital costs.

In addition, because approximately 10 percent of electric demand occurs for less than 150 hours per year, a significant amount of electric capacity is only needed for a few peak hours each year. Natural gas fueled generation can supply peaking and firming capacity because these units can start and ramp-up quickly. Peaking capacity generally costs more per kWh because it is used in only a few peak hours per year and thus capital costs are spread over fewer hours. Recently, the utilities have added new

[25] Bilateral contracts represent natural gas contracts only.

peaking capacity to meet overall capacity requirements, particularly in transmission-constrained areas. As a result, UOG and contracted natural gas-fired generation costs are higher than would otherwise be expected in light of recent low gas prices.

Renewable Energy Procurement

SB 1078 established the Renewable Portfolio Standard (RPS) in 2002, requiring the state to meet 20% of its electricity demand from eligible renewable energy resources by 2010 and to maintain 20% renewables thereafter. Eligible resources include wind, solar photovoltaics, solar thermal, tidal wave, small hydroelectric, geothermal, biodiesel, biomass and biogas. In 2011, SB 2 increased targets to 33% by 2020.

On October 7, 2015, Governor Brown approved SB 350 (De León) or the "Clean Energy and Pollution Reduction Act of 2015." The bill revises the current RPS target to obtain 50% of total retail electricity sales from renewable resources by December 31, 2030, with interim targets of 40% by December 31, 2024, and 45% by December 31, 2027. Among other things, this bill also establishes into law: an integrated resource planning process for electric load-serving entities.

As of 2017, the IOUs were serving an estimated 36.3% of their generation from renewable resources but that generation accounts for an average of 21.4% of their total revenue requirement. From 2003 to 2016, the average time-of-delivery adjusted price of contracts approved by the CPUC has decreased from 9.4 cents to 6.2 cents/kWh in real dollars (it increased from 6.2 cents to 6.9 cents/kWh in nominal dollars).[26]

Other Power Purchases

Additional power purchase and sale mechanisms exist to ensure that the utilities have secured 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. 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

[26] The CPUC used the Handy- Whitman Index of Public Utility Construction Costs – Transmission Production Plant - Pacific region to calculate the real dollar amounts for year 2017.

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

Electric utilities have been regulated under California's Greenhouse Gas (GHG) Cap-and-Trade Program since January 1, 2013. As covered entities under the program, the electric utilities must buy and surrender compliance instruments - offsets and allowances - to the California Air Resources Board (ARB) to account for each unit of GHG emissions. ARB holds quarterly allowance auctions where entities can buy and sell allowances.

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

ARB allocates some allowances to electric utilities on behalf of their ratepayers. The Cap-and-Trade regulation requires the investor-owned electric utilities to sell all of these allowances at ARB's quarterly allowance auctions. The proceeds the utilities receive from the sale of GHG allowances must be used exclusively for ratepayer benefit, consistent with the goals of AB 32, and as directed by the CPUC. Consistent with the direction in SB 1018 (2012), the CPUC has determined the methodologies the utilities should use to return revenues to industrial ("emissions-intensive and trade-exposed"), small business, and residential customers. AB 693 (2015) directed $100 million of allowance proceeds, annually, be allocated to solar energy systems in disadvantaged communities. In response, the CPUC established the Solar on Multifamily Affordable Housing (SOMAH) Program in December 2017.

Beginning in 2014, the electric utilities began introducing Cap-and-Trade-related costs into electricity rates and distributing allowance proceeds to customers. In 2016, the electric IOUs collectively introduced approximately $631 million in GHG costs into rates and returned approximately $902 million in allowance proceeds to customers.

In 2017, the electric IOUs collectively introduced approximately $485 million in GHG costs into rates and returned approximately $741 million in allowance proceeds to customers (see **Table 4.1**).

Table 4.1: 2017 Summary of Greenhouse Gas Costs and Allowance Proceeds ($000)

Utility	2017 Electric GHG Costs	2017 Electric Proceeds Distributed to Customers
PG&E	181,239,936	(310,890,000)
SCE	272,216,116	(340,221,507)
SDG&E	31,480,301	(89,768,213)
Total	**484,936,353**	**(740,879,720)**

Other Factors Affecting 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 price has a significant effect on the cost of many types of generation:

> **Natural Gas Prices:** Gas prices cause natural gas generation costs to be more volatile than other forms of generation. Spot market purchases, DWR contracts, cogeneration QFs and spot market purchase power costs fluctuate and track with gas prices, which fell precipitously in 2008. 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. Gas prices spiked after Hurricane Katrina in 2005 and have since returned to steady levels. Renewables contracts generally exhibit more cost stability because they are reliant on gas prices.

V. Demand-Side Management and Customer Programs

Demand-Side Management (DSM) involves various programs and activities on the customer side of the meter to reduce, curtail, or shift demand for electricity through energy efficiency, demand response, or self-supply through distributed generation. In 2003, the CPUC and the CEC adopted the Energy Action Plan to establish goals for the state's energy strategy.[27] The plan established that cost effective energy efficiency and demand response are at the top of the loading order – the preferred means for meeting the state's growing energy needs – followed by renewable energy and distributed generation.

The revenue requirements for DSM primarily consist of financial incentives to encourage DSM activities and the administrative costs to manage these programs. In order to achieve the goals established in the Energy Action Plan, spending on DSM has experienced a 12.0% average annual increase since 2005 as the California Solar Initiative (CSI) and demand response programs were initiated and energy efficiency programs doubled in size. In total, DSM programs combined accounted for 4.6% of the total revenue requirement (actual EE program expenditures). However, the savings associated with these programs are not reflected in the IOUs' overall revenue requirement. In addition to DSM, California also mandates customer programs to provide rate discounts and energy efficiency improvements for low-income customers. **Table 5.1** shows the DSM and customer program costs recovered in rates.

Table 5.1: 2017 Demand Side Management and Customer Programs Costs ($000)[28]

	PG&E	SCE	SDG&E	Total
Energy Efficiency	329,633	338,197	107,199	**775,028**
Demand Response	66,521	76,850	15,959	**159,330**
California Solar Initiative	7,959	8,840	3,560	**20,359**
Self-Generation Incentive Program	29,988	27,999	10,035	**68,022**
Electric Program Investment Charge	89,000	69,840	24,790	**183,630**
New Home Solar Partnership	45,916	46,000	0	**91,916**
California Alternative Rates for Energy	38,211	(15,098)*	66,930	**90,043**
Energy Savings Assistance	81,691	62,376	15,168	**159,235**
Other PPP Programs	10,530	110,287	4,600	**125,417**
Other Regulatory	(187,176)	(335,310)	261,920	**(260,566)**
Total	**512,273**	**389,980**	**510,162**	**1,412,415**

*SCE forecasted an over-collection in the CARE balancing account to be returned to ratepayers.

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

[28] Based upon the forecasted 2017 program costs. Revenue requirement for Demand Side Management, California Solar Initiative, Self-Generation Incentive Program, and other regulatory (-$83 million for PG&E, -$222 million for SCE, and $291 million for SDG&E) is collected through the distribution rate component.

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.

The gas portion of the energy efficiency portfolios is funded through the gas Public Purpose Program (PPP) component of rates and 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 budget averages approximately $1 billion per year for 2016 and 2017(see **Figure 5.1**).

Programmatic efforts over this time resulted in reported program savings of 2,289 GWh, 445MW, and 44 MMtherms.[29] That is enough electricity savings to power about 327,000 homes for one year, and enough gas savings to avoid the need for about three-quarters of a natural-gas power plant.

Like former programs, these programs continue to support residential, 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 has also supported programmatic activities targeted at the long term transformation of consumer energy markets through education, training, and other initiatives—though the savings benefits associated with these efforts are difficult to quantify and the CPUC has historically elected not to attempt to do so.

[29] Reported savings estimates are net and are available from EEStats (http://eestats.cpuc.ca.gov/).

Figure 5.1: Savings & Expenditures from Non-Codes and Standards IOU Program[30]

Year	2016	2017	Grand Total
All Investor Owned Utilities			
Electric (GWh)	**1170**	**1119**	**2289**
Demand (MW)	**263**	**182**	**445**
Natural Gas (MMTh)	**21**	**23**	**44**
Carbon (1000 Tons CO2)	**715**	**703**	**1417**
Total Expenditures ($M)	**$885**	**$1,169**	**$2,054**
PGE			
Electric (GWh)	518	496	1014
Demand (MW)	112	81	193
Natural Gas (MMTh)	10	19	29
Carbon (1000 Tons CO2)	327	364	691
Total Expenditures ($M)	$393	$555	$948
SCE			
Electric (GWh)	511	544	1055
Demand (MW)	96	89	185
Natural Gas (MMTh)	-	-	-
Carbon (1000 Tons CO2)	256	254	510
Total Expenditures ($M)	$282	$387	$669
SCG			
Electric (GWh)	-	-	-
Demand (MW)	-	-	-
Natural Gas (MMTh)	9	6	16
Carbon (1000 Tons CO2)	51	39	90
Total Expenditures ($M)	$78	$115	$192
SDGE			
Electric (GWh)	141	75	216
Demand (MW)	55	9	65
Natural Gas (MMTh)	2	1	3
Carbon (1000 Tons CO2)	81	45	126
Total Expenditures ($M)	$132	$112	$244

Demand Response

Demand Response (DR) generally refers to the reduction (by end-use customers) of electricity usage during peak periods (or shifting of usage to another time period), in response to a price signal, financial incentive, environmental condition or reliability

[30] Table Notes: 2017 data does not include Q4 data which will be available March 1st, 2018; Savings data does not include REN/CCAs or Codes and Standards advocacy savings; Savings data is reported net, first-year savings; Data does not include Energy Savings Assistance Program savings and costs; IOU Expenditures are reported at the program level and are not broken down into gas vs. electric expenditures.

signal. DR programs save ratepayers money by reducing the need to build power plants or avoiding the use of older, less efficient power plants that would otherwise be necessary to meet peak demand. The reduction in peak demand also lowers the price of wholesale energy and, in turn, retail rates. DR goals are met through customer programs which more and more involve controls on end uses such as air conditioning units, which automate the customer's response to a CAISO signal. DR programs are 'bid' as a resource in CAISO energy markets, enabling them to compete against generation bids and to be dispatched when and wherever needed by the CAISO. Future demand response 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 demand response to alleviate electricity supply shortages in certain local areas of the state with constraints on transmission capacity.

Demand Response Customer Programs

These programs were historically aimed at large commercial and industrial customers that can shed significant amounts of load as an immediate or day ahead response. There are programs for residential customers as well (e.g., AC Cycling). With the advent of smart meters, and smart thermostats in recent years, residential customer participation has grown. Additionally, some demand response programs are arranged by third-party operators also known as "Aggregators" or "Demand Response Providers" which gives customers more choices beyond programs run by utilities. Customers are provided bill credits or payments to participate in the programs and customers are called to curtail load to meet the needs for system reliability or peak capacity management. The costs for these programs are in administration, incentives, marketing/customer education, measurement/evaluation, IT infrastructure and pilots. One of the third-party programs – the Demand Response Auction Mechanism (DRAM) – is operated outside the utility program portfolios. Under the DRAM pilot, utilities procure capacity through bids that include all costs except for utility technology incentives, and limited utility marketing. For 2017, the maximum potential capacity reduction resulting from the DR programs, including load modifying rates and DRAM, was forecasted at 2,229 MW.

Customer Generation

Over the past several years, 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. Ratepayers fund three Distributed Generation (DG) programs that provide financial incentives to participating customers – the California Solar Initiative (CSI),the Self-Generation Incentive Program (SGIP), and the Solar on Multifamily Affordable Housing (SOMAH) Program. In addition, Net Energy Metering (NEM) provides customer generators with bill credits for power generated by their onsite systems that is fed back into the grid.

California Solar Initiative (CSI)

Established in 2006, the CSI program provided either up-front incentives or performance-based payments for the installation of photovoltaic solar systems up to 1 megawatt (MW) on existing residential homes as well as existing and new commercial, industrial, government, non-profit and agricultural properties within the service territories of the IOUs. The CSI program set a budget of $2.367 billion over 10 years and a goal of reaching 1,940 MW of installed solar capacity from the general market program and two low-income programs.[31] Additionally, the CSI Thermal program, which incentivizes gas-displacing solar technologies, was established in 2007 and has a budget of $250 million and a goal of establishing a mainstream market for solar thermal systems that directly reduces demand for natural gas in California.

- The CSI General Market incentive program closed on December 31, 2016. Program administration will continue until December 31, 2019 in order to allow sufficient time for CSI program administrators to process remaining performance-based payments. The CSI low-income programs – the Single-family Solar Affordable Solar Housing (SASH) Program and Multifamily Affordable Solar Housing (MASH) Program – are ongoing, though the incentives for MASH are fully reserved.

- The installed capacity under the CSI General Market program was 1,904 MW. To-date, 27.4 MW of capacity has been installed under the MASH Program and 0.8 MW are pending and scheduled for completion. The MASH Program funding has been exhausted. In addition, 16 MW have been installed under the SASH Program. As of the end of January 2018, an estimated 6,605 solar thermal systems were installed on the customer side of the meter with an additional 25 systems pending in CSI Thermal applications.

Self-Generation Incentive Program (SGIP)

Established in 2001, SGIP provides incentives to support distributed energy resources that will result in greenhouse gas (GHG) emission reductions and peak demand reductions. With 2,667 completed projects, totaling 698 megawatts of capacity,[32] SGIP is one of the longest-running DG incentive programs in the country.

- The program was reauthorized by SB 861 (2014) to continue through 2020. Also, pursuant to AB 1637 (Low, 2016), the CPUC was authorized to double the amount of funding collected by the IOUs for SGIP every year from $83 million to $166 million for calendar years 2017-2019. The program funds are collected from PG&E, SCE, SDGE and SoCalGas.

- 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

[31] The low-income CSI programs were extended in 2015 and received an additional $54 million each, which increases the total CSI budget to $2.475 billion through 2021.

[32] See https://energycenter.org/sgip/statistics

larger 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.

- A cost-effectiveness study of SGIP was issued in October 2015.[33] An SGIP Impact Evaluation for 2014-2015 was released on November 4, 2016.[34] In addition, a 2016 SGIP Advanced Energy Storage Impact Evaluation was released on August 31, 2017.[35]
- CPUC Decision 17-10-004 created the SGIP Equity Budget, which will allocate 25% of SGIP funds already allocated for energy storage projects to, and will provide incentives for customer-sited energy storage in disadvantaged communities and low-income communities in California. Eligible customers include low income households, state and local government agencies, educational institutions, non-profits, and small businesses.

Solar on Multifamily Affordable Housing (SOMAH) Program

Assembly Bill (AB) 693 (Eggman, Chapter 582, 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 Commission issued D.17-12-022 that outlined the program design for the new Solar on Multifamily Affordable Housing (SOMAH) program in the territories of PG&E, SCE, SDGE, Liberty Utilities and PacifiCorp. In addition to building on many of the program successes and lessons learned from the CSI-funded Multifamily Affordable Solar Housing (MASH) Program, the SOMAH program seeks to:

- Direct up to $100 Million, annually, from the electric IOU's Greenhouse Gas Auction Proceeds towards subsidized solar energy systems on multifamily affordable housing.
- Encourage the development and installation of solar systems in California's disadvantaged communities
- Emphasize the explicit goal that incented solar systems lower the energy bills of tenants of low-income multifamily housing, and reduce the CARE subsidy funded by other ratepayers
- Develop, by December 31, 2030, at least 300 megawatts of installed solar generating capacity.

Net Energy Metering (NEM)

Residential and commercial customers who install small RPS-eligible generation facilities to serve all or a portion of onsite electricity needs are eligible for the state's NEM program. NEM allows customer-generators to receive a full retail-rate bill credit for energy generated by their on-site system that is fed back into the utility grid during times when on-site generation exceeds a customer's energy demand. The credit is used to

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See http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=7889

See http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451496

[35]See http://cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442454964

offset the customers' electricity bills and may be rolled over to subsequent billing periods for up to a year.

In January 2016, the CPUC approved a decision adopting a NEM successor tariff for customers receiving NEM service after each IOU reached its 5% NEM capacity cap. The current NEM Successor Tariff program went into effect in SDG&E's territory on June 29, 2016, in PG&E's territory on December 15, 2016, and in SCE's territory on July 1, 2017. Customers on the NEM Successor Tariff must pay non-bypassable charges on each kWh of energy they consume from the grid within a metered interval.[36]

Low-Income Programs

In addition to the low-income and disadvantaged community programs mentioned previously, the IOUs provide two ratepayer-funded energy assistance programs for qualifying low-income customers meeting the income limits at or below 200% of federal poverty guideline. The California Alternate Rates for Energy program (CARE) offers rate discounts off low income customers' energy bills, and the Energy Savings Assistance program (ESA) provides no-cost in-home weatherization services, energy efficiency measures and energy education to help eligible low-income households conserve energy, reduce energy costs and improve their health, comfort and safety.

California Alternate Rates for Energy (CARE)

The CARE program, previously referred to as Low Income Ratepayer Assistance (LIRA) Program is a low-income energy rate assistance program that provides a discount on energy rates to qualifying low-income households. CARE is funded by non-participating CARE customers as part of a statutory "public purpose program surcharge" that appears on monthly utility bills.

The program was established in 1989 by P.U. Code Sections 739.1 and 739.2, authorizing a 15% rate discount for qualifying low-income customers off their energy bills. In 2001, the minimum CARE rate discount was increased from 15% to 20% by CPUC Decision 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 above 40% for some CARE customers. In October 2013, AB 327 was passed requiring the IOUs to restructure the CARE discount rates and to set an effective electric rate discount between 30-35%. Currently the discount is between 32-38% for electric charges and 20% for natural gas charges, as they are being reduced in phases to prevent rate shock. In 2017, PG&E's CARE effective electric discount was 36%, whereas SCE's was 32.5% and SDG&E's was 38%. In compliance with AB 327 and D.15-07-001, the effective discount will be reduced to 35% for PG&E, will remain at 32.5% for SCE and will be reduced to 35% for SDG&E. These reductions will take place gradually between now and 2020.

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

In 2017, the program provided approximately $1.3B in annual subsidies and served approximately 4.5 million low income households statewide.[37] 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.

PG&E's CARE subsidy in 2017 was approximately $643 million, compared to $375 million for SCE, $108 million for SoCalGas and $114, million for SDG&E (see **Table 5.2**).

Table 5.2 2017 CARE Program Costs[38]

Utility	Operations	Subsidy	Administrative Costs	Total
PG&E	Electric	$533,683,875	$10,559,954	$544,243,829
	Gas	$109,854,309	$2,608,957	$112,463,266
SCE	Electric	$375,043,839	$6,706,298	$381,750,137
SDG&E	Electric	$103,112,723	$5,331,263	$108,443,986
	Gas	$10,916,625	$592,363	$11,508,988
SoCalGas	Gas	$107,960,958	$8,530,791	$116,491,749
Total		**$1,240,572,329**	**$34,329,626**	**$1,274,901,955**

Energy Savings Assistance Program (ESA)[39]

The ESA program, formerly known as the Low Income Energy Efficiency or LIEE program, provides no-cost home weatherization services, energy efficiency measures (including water-energy saving measures), and energy education to help eligible low-income households conserve energy, reduce energy costs and improve their health, comfort and safety. The program is funded by ratepayers as part of a statutory "public purpose program surcharge" that appears on monthly utility bills.

The original objective of the program was to promote equity and to help relieve low-income customers of the burden of rising energy prices, and since has also evolved into a resource program that should garner significant energy savings while also improving the quality of life for low-income customers.

In 1990, the California legislature adopted and codified the ESA program in California Public Utilities Code Section 2790(a) 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 the hardships facing low-income households. In 2007, the Commission 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 those who wish to participate all cost-effective energy efficiency measures in their residences by 2020. This goal was later codified into California Public Utilities Code Section 382(e) which requires that, by 2020,

[37] Source: Investor Owned Utilities' Dec 2017 Monthly CARE and ESA program Report

[38] Source: Investor Owned Utilities' Dec 2017 Monthly CARE and ESA program Report

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

100% of all eligible and willing low income customers will be given the opportunity to participate in the program.

Customers are enrolled into the program through various channels including leads from CARE program participants, door to door neighborhood canvasing, direct mail, email, community based organizations, categorical enrollment, and community events. ESA is an income verified program, however customers can also enroll automatically if their household is already enrolled in another financial assistance program with similar financial criteria. As the program matures and nears its 2020 goal, the program will be targeting high energy usage and hard to reach customers not yet enrolled. **Table 5.3** shows the 2017 ESA program costs. In 2017, the ESA program served 270,000 households, achieved 87 GWh and 3 MMtherms, and accounted for approximately 1% of the IOUs' total revenue requirement.

Table 5.3: 2017 ESA Program Costs[40]

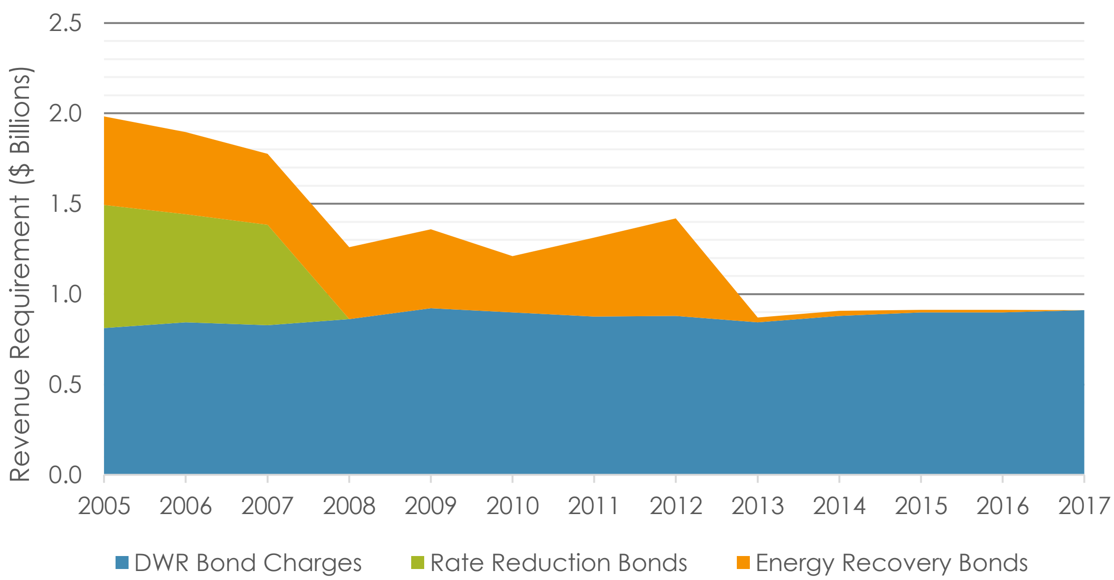
	Utility	Expenditures
PG&E	Electric	$70,256,215
	Gas	$50,785,535
SCE	Electric	$59,321,530
SDG&E	Electric	$8,788,974
	Gas	$8,571,061
SoCalGas	Gas	$77,493,310
Total		**$275,216,625**

[40] Source: Investor Owned Utilities' Dec 2017 Monthly CARE and ESA program Report

VI. Bonds and Regulatory Fees

During the era of electric restructuring, the State and the utilities issued a series of bonds in order 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 $0.9 billion in 2017, as illustrated in **Figure 6.1**.

Figure 6.1: Trends in Bond 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%.

Department of Water and Resources (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 June 30, 2015, a $5.6 billion balance remained outstanding on the DWR bonds.[41] The balance is scheduled to be repaid by 2022.

Regulatory Asset / Energy Recovery Bonds: As part of the CPUC and PG&E bankruptcy settlement agreement, PG&E 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.

[41] Department of Water Resources Electric Power Fund Financial Statements, June 30, 2015 p. 25, available at http://www.cers.water.ca.gov/pdf_files/101615_epf.pdf

Table 6.1 shows the bond expenses component of the 2017 revenue requirement for each of the electric IOUs.

Table 6.1: 2017 Bond Expenses ($000)

	PG&E	SCE	SDG&E	Total
DWR Bond Charges	406,896	414,068	91,076	912,040
Rate Reduction Bonds	0	0	0	0
Energy Recovery Bonds	(432)	0	0	(432)
Total	**406,463**	**414,068**	**91,076**	**911,608**

Fees and Incentives

Fees include a variety of charges levied by federal, state and local governments. For example, the CPUC fee reimburses the state for the cost of regulating the utilities. Incentives offer a financial inducement for utilities to achieve certain policy goals that may not be effectively accomplished only through regulatory directives. **Table 6.2** shows the 2017 revenue requirement for regulatory fees. In total, this entire category of expenses accounted for roughly 1% of the 2017 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: 2017 Regulatory Fees ($000)

	PG&E	SCE	SDG&E	Total
Fees				
CPUC Reimbursement Fee*	35,694	20,648	0	56,342
Franchise Fee & Uncollectible Surcharge**	0	4,032	4,086	8,118
Catastrophic Events Memo Account	0	0	0	0
Hazardous Substance Mechanism	20,438	0	0	20,438
Nuclear Decommissioning***	125,779	(2,581)	(11,027)	112,171
Spent Nuclear Fuel	0	4,110	1,026	5,136
Major Emergency Balancing Account****	(4,016)	0	0	(4,016)
Total	**177,896**	**26,209**	**(5,915)**	**198,190**

* SDG&E did not include the CPUC fee in the revenue requirements reported here, but does collect this fee as a separate charge on the utility bill.
** Not reported elsewhere
*** Includes Nuclear Decommission franchise fees and uncollectible expense as applicable

**** 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.

Definition of Fees

- **CPUC Reimbursement Fee:** This is the annual fee to be paid by utilities to fund their regulation by the Commission (Public Utilities (PU) Code Section 401-443). The surcharge to recover the cost of that fee is ordered by the Commission 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.[42]
- **Uncollectibles:** Includes accounts receivable that have defaulted or cannot be collected.
- **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 Commission not to be eligible for recovery through the CEMA process may be recoverable through the MEBA.

[42] PG&E reported $0 for franchise fees in 2017 and in several other years past, suggesting that they may have been reported in other cost categories after recovery in surcharges, and not recorded here.

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 Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SoCalGas) and San Diego Gas and Electric Company (SDG&E). Unlike the process for electric utilities, the CPUC does not set an annual authorized revenue requirement for natural gas utilities' procurement costs. 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. Consumer behavior can be brought into closer alignment quicker with commodity gas prices by incorporating monthly price changes in consumer bills, rather than doing so on a longer-term basis. By doing so, the impact of price variation affects current ratepayers as opposed to past or future ratepayers.

Natural gas utility costs may be categorized into the following three main components: 1) core procurement costs, 2) costs of operating the natural gas utility system and providing customer services, and 3) costs associated with gas public purpose programs (PPP). **Table 7.1** shows the 2017 natural gas revenue requirement by components.

Table 7.1: 2017 Gas Revenue Requirement Summary by Key Components ($000)

	PG&E	SoCalGas	SDG&E	Total
Core Procurement	1,158,601	1,154,731	151,850	2,465,182
Transportation	3,184,277	2,693,301	397,819	6,275,397
Public Purpose Programs	267,938	343,321	36,001	647,260
TOTAL	**4,610,816**	**4,191,353**	**585,670**	**9,387,839**

For 2017, total natural gas utility costs decreased by 0.6% from 2016 compared to the 11.9% increase for 2015-2016 and the 0.2% increase from 2014 to 2015. Compared to 2016, in 2017, PG&E's total natural gas utility costs decreased by 3.7%, SoCalGas's costs increased by 2.3%, and SDG&E's costs increased by 4.2%.

As the tables below show, gas utility transportation and distribution costs have decreased by 7.1% from 2016 to 2017. Procurement costs increased 20% in the same period due to the increase in natural gas prices. Natural gas public purpose program costs increased by 1.2% from 2015 to 2016, mostly due to expenditures for California Alternative Rates for Energy (CARE) and low-income energy-efficiency programs, both of which are designed to subsidize low-income households' utility bills. **Figure 7.1** and **Figure 7.2** show the trends in natural gas utility revenue requirements.

Figure 7.1: Trends in Gas Utility Revenue Requirements ($Billions)

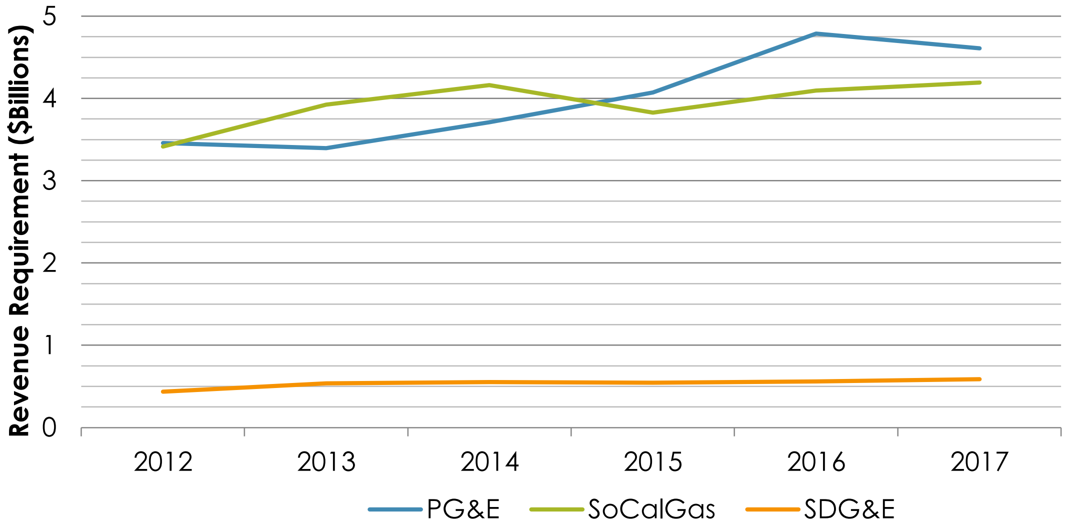


Figure 7.2: Trends in Gas Utility Revenue Requirement Components ($Billions)

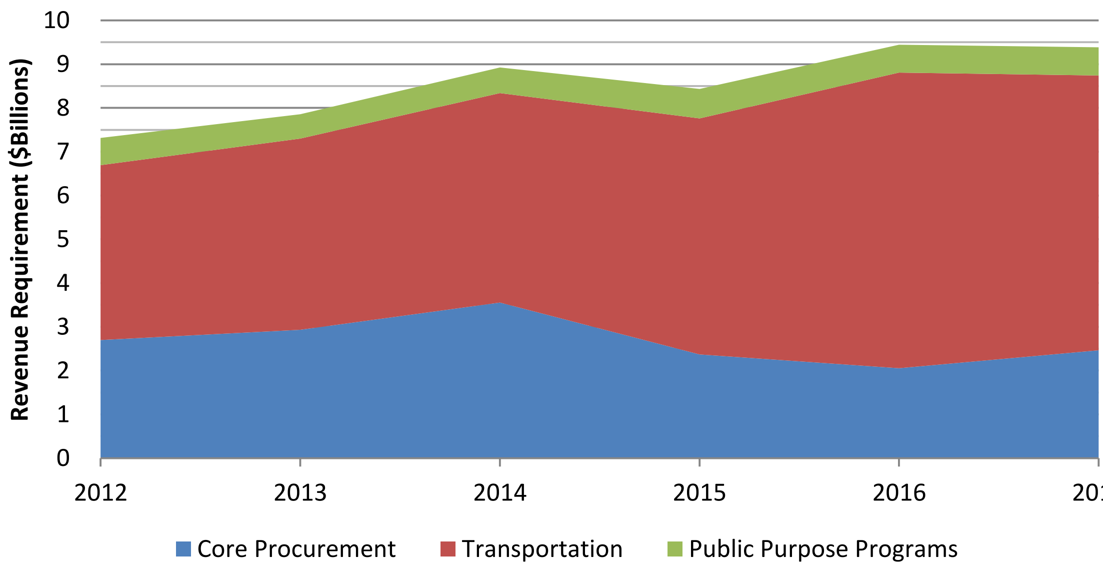


Table 7.2 and **Table 7.3** show historic revenue requirements and the percent change from 2015 to 2017.

Table 7.2: Historic Gas Utility Revenue Requirement ($000)

	2012	2013	2014	2015	2016	2017
Core Procurement	2,696,629	2,932,620	3,553,256	2,371,796	2,053,768	2,465,182
Transportation	3.994.102	4,370,631	4,788,140	5,390,916	6,753,286	6,275,397
Public Purpose Programs	621,657	551,281	581,915	670,067	639,808	647,260
Total	**7,312,388**	**7,854,532**	**8,425,311**	**8,432,779**	**9,446,862**	**9,387,839**

Table 7.3: Percent Change in Gas Utility Revenue Requirements (2015 to 2017)

	Core Procurement	Transportation	Public Purpose Programs
PG&E	(11%)	27%	(1%)
SoCalGas	21%	7%	(6%)
SDG&E	16%	5%	4%
Change Total	**4%**	**16%**	**(3%)**

Core Gas Procurement

The major natural gas utilities recover core customer procurement costs through a rate component called the gas procurement rate. The gas procurement rate is changed every month to reflect the most current price of natural gas. The procurement rates are changed routinely through utility advice letter filings with the CPUC. Core gas procurement costs in 2017 increased by 20% from 2016, due to an increase in natural gas prices. Overall, natural gas core procurement costs have increased by 4% since 2015. In 2017, core gas procurement costs accounted for about 26% of the total utility costs.

Core gas customers – primarily residential and small commercial accounts – in California have the option to choose between utility gas procurement service and gas procurement service from other entities called Core Transport Agents (CTAs). In 2013, Core Transport Agent service grew in popularity, particularly in PG&E's service territory, prompting the passage of a new bill to regulate CTAs under the California Public Utilities Code. However, despite the increase in CTA popularity, the vast majority (over 80%) of core gas customers still receive utility gas procurement service. Almost all larger, "noncore" natural gas consumers--industrial customers or electric generators--procure their own natural gas supplies using non-utility suppliers. Thus, the procurement costs shown in this section reflect only the costs to the utilities of providing procurement service to core customers.

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. The major component of core procurement costs is the cost of the commodity itself.

Due to a significant decrease in the price of natural gas since mid-2008, the state's natural gas utilities' procurement costs have fallen 25% from 2011 to 2017, but risen 20% from 2016 to 2017.

Neither the Commission nor the FERC regulates the wholesale price of natural gas. The decrease in the price of natural gas has resulted from developments in the natural gas commodity market. **Figure 7.3** and **Table 7.4** show the historical revenue requirements for natural gas core procurement.

Figure 7.3: Revenue Requirements for Utility Natural Gas Core Procurement ($Billions)

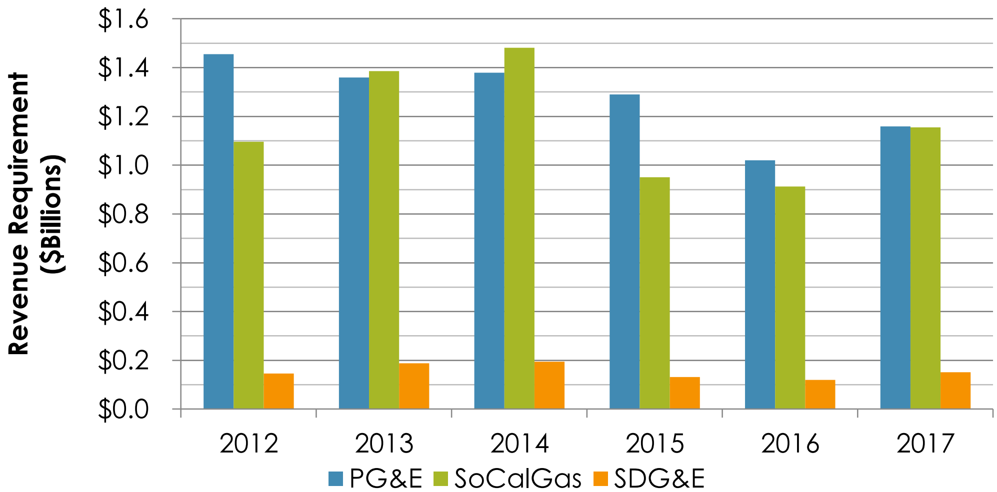


Table 7.4: Historical Revenue Requirement for Core Procurement ($000)

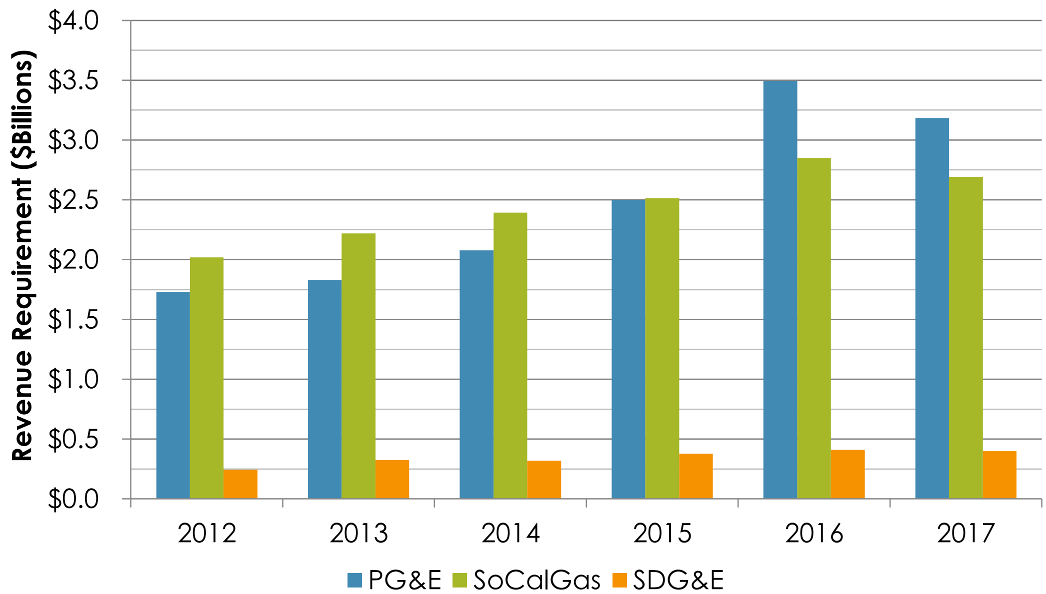
	2011	2012	2013	2014	2015	2016	2017
PG&E	1,520,282	1,455,016	1,359,218	1,378,948	1,289,757	1,020,570	1,158,601
SoCalGas	1,538,869	1,095,871	1,385,335	1,481,448	951,033	912,847	1,154,731
SDG&E	206,615	145,742	188,067	194,860	131,006	120,352	151,850
Total	**3,265,766**	**2,696,629**	**2,932,620**	**3,055,256**	**2,371,796**	**2,053,769**	**2,465,182**

Gas Transmission, Distribution and Storage Costs

The Commission 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. In 2017, gas transportation costs decreased by 7% and represented about 67% of total utility gas costs. The bulk of these revenue requirements are primarily determined by the CPUC in two types of major proceedings: 1) general rate cases for PG&E, SoCalGas and SDG&E and 2) PG&E gas transmission and storage proceedings.

The following table shows that increases in total authorized revenue requirements for transmission, distribution, storage, and customer services, combined under the "transportation" category, have increased by 57% from 2012 to 2017. Such costs increased by 84%, 33% and 62% for PG&E, SoCalGas, and SDG&E, respectively, from 2012 to 2017. With the recent emphasis on safety and replacement of aging infrastructure, the CPUC has authorized increased revenue requirements for all of the three major gas utilities with respect to transmission and distribution. **Figure 7.4** shows the historic revenue requirements for transmission, distribution and storage.

Figure 7.4: Revenue Requirements for Utility Natural Gas Transmission, Distribution, and Storage ($Billions)



In the 2016 Report, the revenue requirements for transportation (**Table 6.9**) were incorrectly reported for PG&E as $3,292,033, for SoCalGas as $2,850,150, and for SDG&E as $408,148. These are corrected in **Table 7.5** in this 2017 Report.

Table 7.5: Historic Revenue Requirements for Transportation Summary ($000)

	2012	2013	2014	2015	2016	2017
PG&E	1,731,021	1,828,380	2,076,507	2,500,926	3,494,033	3,184,277
SoCalGas	2,018,108	2,218,229	2,392,986	2,511,953	2,850,105	2,693,301
SDG&E	244,973	324,022	318,647	378,037	409,148	397,819
Total	**3,994,102**	**4,370,631**	**4,788,140**	**5,390,916**	**6,753,286**	**6,275,397**

Gas Public Purpose Program (PPP) Costs

The Commission also authorizes costs for three main categories of gas PPPs: energy efficiency (EE) and low-income EE, the California Alternate Rate for Energy (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.

Costs authorized by the CPUC in 2017 for natural gas PPPs increased by 1% from 2016. Decreased costs were driven primarily by low-income programs: Low-Income Energy Efficiency and California Alternate Rates for Energy (CARE). Gas PPP costs made up 7% of total utility costs in 2017.

Gas PPP costs are recovered through the gas PPP surcharge on core and non-exempt noncore customers. Only non-CARE customers pay for the CARE subsidy portion of the gas PPP surcharge. The gas PPP surcharges are changed annually through advice letter filings, incorporating the revenue requirements for the gas PPPs adopted in CPUC proceedings. **Figure 7.5** and **Table 7.6** show the historic revenue requirements for public purpose programs.

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

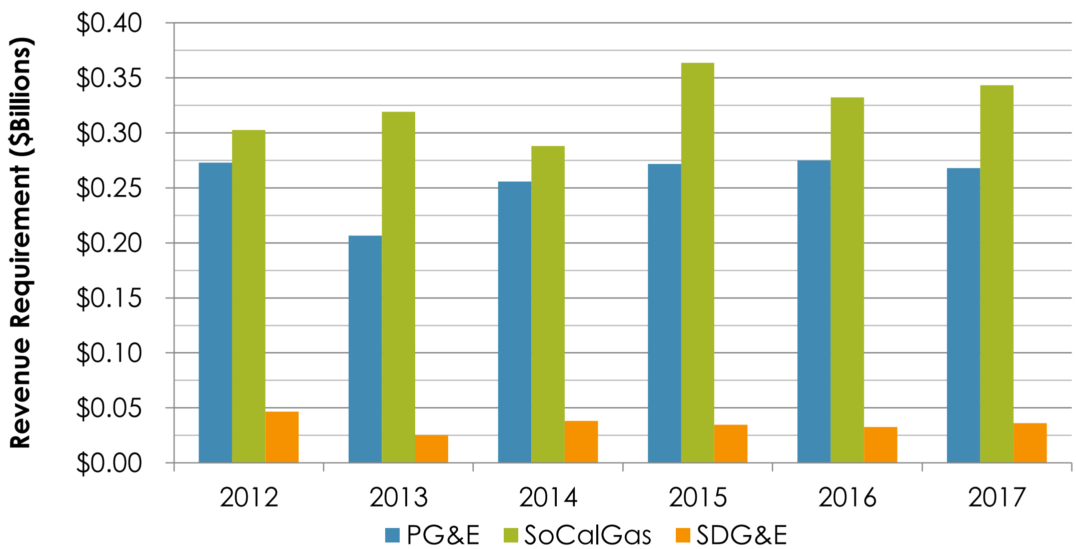


Table 7.6: Historic Revenue Requirements for Public Purpose Programs Summary ($000)

	2012	2013	2014	2015	2016	2017
PG&E	273,008	206,563	255,754	271,726	275,079	267,938
SoCalGas	302,506	319,252	287,906	363,588	332,206	343,321
SDG&E	46,583	25,466	38,255	34,753	32,523	36,001
Total	**622,097**	**551,281**	**581,915**	**670,067**	**639,808**	**647,260**

Appendix A: Historical Electric Revenue Requirements 2017-2015

2017 Revenue Requirements ($000)

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total			**6,210,080**	**5,569,248**	**1,814,687**
Qualifying Facilities	Federal PURPA, 1978; PUC Section 454.5(d)(3)	CPUC Decisions	97,880	2,485,433	41,886
General Rate Case Revenues		CPUC Decisions	1,948,890	605,317	289,538
Renewable Portfolio Standard	PUC Section 454.5(d)(3)	CPUC Decisions	2,292,419	Included with Qualifying Facilities	775,090
Other Utility Fuel & Purchased Power	PUC Section 454.5(d)(3)	CPUC Decisions	1,864,807	2,323,409	775,067
Other		CPUC Decisions, Resolutions	6,085	155,090	(66,893)
Transmission Total			**1,936,457**	**1,011,823**	**582,004**
Reliability Services	FERC Order 459		0	14,308	3,077
Transmission Access Charge	FERC		529,280	(83,659)	(171,143)
Transmission Owner Rate Case Revenues	FERC		1,522,521	1,188,758	775,937
Other - FERC Rate Case Revenues	FERC		(115,344)	(107,584)	(32,778)
Other			0	0	6,911
Distribution Total			**4,717,006**	**4,667,759**	**1,284,950**
General Rate Case Revenues		CPUC Decisions	4,717,006	4,667,759	1,284,950
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**125,779**	**1,529**	**(10,001)**
Demand Side Management and Customer Programs Total			**512,273**	**389,980**	**510,162**
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	29,988	27,999	10,035
California Solar Initiative		CPUC Decisions	7,959	8,840	3,560
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	66,521	76,850	15,959
Energy Efficiency, PU Code 399.8	PUC Section 399.8	CPUC Decisions, E-3792	120,865	338,197	0
Energy Efficiency (non-PUC 399.8)			208,767	0	107,199
Electricity Program Investment Charge		CPUC Decisions	89,000	69,840	24,790
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	81,691	62,376	15,168
CARE Admin., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	38,211	(15,098)	(24,471)
Renewables	PUC Section 399.8	CPUC Resolution E-3792	0	0	0
Other PPP		CPUC Decisions, Resolutions	56,446	156,287	96,001
Other		CPUC Decisions, Resolutions	(187,176)	(335,310)	261,920
Other Regulatory Total*			**52,117**	**20,648**	**0**
Catastrophic Events	PUC Section 454.9(a)	CPUC Decisions	0	0	0
Hazardous Substance Mechanism		CPUC Decisions	20,438	0	0
CPUC Fee	PUC Section 431	CPUC Resolution M-4816	35,694	20,648	0
Other		CPUC Decisions, Resolutions	(4,016)	0	0
DWR Power Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**(2,516)**	**0**	**0**
DWR Bond Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**406,896**	**414,068**	**91,076**
Ongoing Competition Transition Charge	AB 57, PUC Section 367(a) & 369	CPUC Decisions	**274,363**	**0**	**32,015**
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	**(432)**	**-**	**-**
Franchise Fee Surcharge**	PUC Sections 6350-6354, 6231	CPUC Decisions	**0**	**4,032**	**4,086**
Electric Total			**14,232,023**	**12,079,088**	**4,308,979**

*Recovered in distribution rate component
**Not reported elsewhere.

Appendix A (cont.)

2016 Revenue Requirements ($000)

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total			**6,925,847**	**4,305,858**	**1,600,320**
Qualifying Facilities	Federal PURPA, 1978; PUC Section 454.5(d)(3)	CPUC Decisions	348,936	2,115,227	39,905
General Rate Case Revenues		CPUC Decisions	2,076,532	493,039	284,143
Renewable Portfolio Standard	PUC Section 454.5(d)(3)	CPUC Decisions	2,125,494	0	709,127
Other Utility Fuel & Purchased Power	PUC Section 454.5(d)(3)	CPUC Decisions	2,371,769	1,697,775	567,188
Other		CPUC Decisions, Resolutions	3,116	(184)	(43)
Transmission Total			**1,558,681**	**1,058,025**	**531,095**
Reliability Services	FERC Order 459		16,178	5,111	2,457
Transmission Access Charge	FERC		250,839	(7,754)	(169,798)
Transmission Owner Rate Case Revenues	FERC		1,380,518	1,091,803	707,837
Other - FERC Rate Case Revenues	FERC		(88,855)	(31,135)	(15,774)
Other			0	0	6,373
Distribution Total			**4,982,176**	**4,691,106**	**1,241,696**
General Rate Case Revenues		CPUC Decisions	4,982,176	4,691,106	1,241,696
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**89,542**	**(72,929)**	**(893)**
Demand Side Management and Customer Programs Total*			**643,166**	**665,137**	**316,119**
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	29,988	27,999	10,035
California Solar Initiative		CPUC Decisions	90,853	101,063	34,970
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	(17,863)	97,864	15,959
Energy Efficiency, PU Code 399.8	PUC Section 399.8	CPUC Decisions, E-3792	120,865	0	0
Energy Efficiency (non-PUC 399.8)			236,064	0	101,486
Electricity Program Investment Charge		CPUC Decisions	0	69,815	0
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	96,219	72,710	12,434
CARE Admin., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	21,363	(8,596)	3,356
Renewables	PUC Section 399.8	CPUC Resolution E-3792	0	6,732	14,954
Other PPP		CPUC Decisions, Resolutions	65,675	297,550	122,925
Other Regulatory Total*			**(405,449)**	**246,358**	**149,188**
Catastrophic Events	PUC Section 454.9(a)	CPUC Decisions	0	6,732	0
Hazardous Substance Mechanism		CPUC Decisions	21,363	0	1,698
CPUC Fee	PUC Section 431	CPUC Resolution M-4816	28,322	20,648	0
Other		CPUC Decisions, Resolutions	(455,134)	218,977	147,490
DWR Power Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**(44,531)**	**(15,816)**	**(3,506)**
DWR Bond Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**411,235**	**415,785**	**91,823**
Ongoing Competition Transition Charge	AB 57, PUC Section 367(a) & 369	CPUC Decisions	**191,735**	**0**	**32,395**
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	**(1,663)**		
Franchise Fee Surcharge**	PUC Sections 6350-6354, 6231	CPUC Decisions	**0**	**16,047**	**10,419**
Electric Total			**14,756,188**	**11,309,571**	**3,288,373**

*These items are recovered in the Delivery component of rates.

Appendix A (cont.)

2015 Revenue Requirements ($000)

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total			**7,207,668**	**6,896,260**	**1,565,677**
Qualifying Facilities	Federal PURPA, 1978; PUC Section 454.5(d)(3)	CPUC Decisions	348,936	2,674,431	48,151
General Rate Case Revenues		CPUC Decisions	1,998,784	1,297,855	231,261
Renewable Portfolio Standard	PUC Section 454.5(d)(3)	CPUC Decisions	2,020,553	Included with Qualifying Facilities	590,260
Other Utility Fuel & Purchased Power	PUC Section 454.5(d)(3)	CPUC Decisions	2,836,641	2,925,374	696,005
Other		CPUC Decisions, Resolutions	2,755	(1,400)	0
Transmission Total			**1,482,664**	**923,707**	**470,893**
Reliability Services	FERC Order 459		10,732	(85,755)	4,780
Transmission Access Charge	FERC		219,659	108,987	(267,203)
Transmission Owner Rate Case Revenues	FERC		1,294,362	910,155	739,625
Other - FERC Rate Case Revenues	FERC		(42,089)	(9,680)	(11,824)
Other			0	0	5,514
Distribution Total			**4,534,755**	**4,433,600**	**1,201,767**
General Rate Case Revenues		CPUC Decisions	4,534,755	4,433,600	1,201,767
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**162,769**	**23,506**	**8,560**
Demand Side Management and Customer Programs Total*			**721,966**	**518,077**	**313,267**
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	29,616	28,010	10,035
California Solar Initiative		CPUC Decisions	94,000	82,000	31,417
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	59,356	97,900	20,730
Energy Efficiency, PU Code 399.8	PUC Section 399.8	CPUC Decisions, E-3792	119,446	257,460	0
Energy Efficiency (non-PUC 399.8)			248,175	0	98,643
Electricity Program Investment Charge		CPUC Decisions	72,567	69,846	14,955
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	95,809	72,737	12,432
CARE Admin., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	2,997	(26,239)	4,460
Renewables	PUC Section 399.8	CPUC Resolution E-3792	0	0	0
Other PPP		CPUC Decisions, Resolutions	0	(63,636)	120,595
Other Regulatory Total*			**(427,234)**	**(12,913)**	**465,987**
Catastrophic Events	PUC Section 454.9(a)	CPUC Decisions	0	0	0
Hazardous Substance Mechanism		CPUC Decisions	20,174	0	1,915
CPUC Fee	PUC Section 431	CPUC Resolution M-4816	20,597	20,648	0
Four Corners Gain on Sale		CPUC Decisions	0	(82,960)	0
Other		CPUC Decisions, Resolutions	(468,006)	49,399	464,072
DWR Power Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**(85,503)**	**(124,600)**	**(41,541)**
DWR Bond Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**404,945**	**398,572**	**94,812**
Ongoing Competition Transition Charge	AB 57, PUC Section 367(a) & 369	CPUC Decisions	**194,496**	**(424,476)**	**18,937**
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	**(437,110)**		
Franchise Fee Surcharge	PUC Sections 6350-6354, 6231	CPUC Decisions	**10,696**	**10,940**	**17,779**
Electric Total			**13,770,112**	**12,642,673**	**4,116,137**

*These items are recovered in the Delivery component of rates.

Appendix B: Historical Natural Gas Revenue Requirements 2017-2015

2017 Revenue Requirements ($000)

	Federal/State Mandate	CPUC Mandate	PG&E	SDG&E	SoCalGas
Core Procurement Total			1,158,601	151,850	1,154,731
Core Gas Supply Portfolio		CPUC Decisions	792,973	151,850	1,150,484
Other		CPUC Decisions	354,497	0	0
10/20 Winter Gas Savings		CPUC Resolutions	0	0	0
Core Gas Hedging		Report	5,452	0	0
Incentive Mechanism		Report	5,679	0	4,247
Transportation Total			3,184,277	397,819	2,693,301
Distribution		CPUC Decisions	1,966,317	375,042	2,292,672
Transmission		CPUC Decisions	1,105,365	0	0
Advanced Metering Infrastructure		Report	-	0	79,980
Smart Meter			0	0	0
Self Gen Inc Prog (SGIP)	PUC Section 379.6 (a)	CPUC Decisions	12,989	773	8,135
Climate Smart			0	0	0
Calif Solar Initiative (CSI)		CPUC Decisions	9,998	672	19,643
Annual Earning Assessment (AEAP)		CPUC Decisions	2,308	0	3,375
Low Emission Vehicle (LEV)	PUC Section 740.3 & 740.8	CPUC Decisions	0	0	51,662
Haz Substance Mechanism (HSM)		CPUC Decisions	46,826	(2,384)	3,121
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	0	11,557
Core Pricing Flexibility Program		CPUC Decisions	0	0	1,322
Non core competitive load growth program		CPUC Decisions	0	0	762
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	16,043	(711)	41,893
CPUC Fee	PUC Section 431	Resolution M-4816	6,562	0	0
Franchise Fees & Uncollectibles	PUC Section 6231	CPUC Decisions	5,172	0	0
Franchise Fee Surcharge (G-SUR)	PUC Sections 6350-6354	CPUC Resolutions	9,067	2,304	18,915
AB 32 Cap-And-Trade			3,630	593	5,679
Public Purpose Program Surcharges Total	PUC Sections 399.8, 890-900	CPUC Decisions	267,938	36,001	343,321
Energy Efficiency (EE) Programs	PUC Sections 739.1, 890-900, 2790	CPUC Decisions	71,598	12,943	85,705
Low Income Energy Efficiency (LIEE)	PUC Sections 740, 890-900	CPUC Decisions	69,429	11,340	132,249
Public Interest RD&D and State Board of Equalization (BOE)	PUC Sections 739.1 & .2, 890-900	CPUC Decisions	11,196	1,260	13,002
Calif Alternate Rates for Energy (CARE) Program			115,715	10,458	112,365
GAS TOTAL			**4,610,816**	**585,670**	**4,191,353**

Appendix B (cont.)

2016 Revenue Requirements ($000)

AB 67-Annual Gas Revenue Requirements Components			Jan-Dec 2016 figure ($000)		
	Federal/State Mandate	CPUC Mandate	PG&E	SDG&E	SoCalGas
Core Procurement Total			**1,020,570**	**120,352**	**912,847**
Core Gas Supply Portfolio		CPUC Decisions	643,936	120,352	907,807
Other		CPUC Decisions	362,664	0	0
10/20 Winter Gas Savings		CPUC Resolutions	0	0	0
Core Gas Hedging		Report	7,985	0	0
Incentive Mechanism		Report	5,985	0	5,040
Transportation Total			**3,494,033**	**409,148**	**2,850,105**
Distribution		CPUC Decisions	2,167,826	386,827	2,453,907
Transmission		CPUC Decisions	1,061,912	0	0
Advanced Metering Infrastructure		Report	0	0	122,300
Smart Meter			0	0	0
Self Gen Inc Prog (SGIP)	PUC Section 379.6 (a)	CPUC Decisions	6,505	773	8,136
Climate Smart			0	0	0
Calif Solar Initiative (CSI)		CPUC Decisions	7,056	2,257	12,414
Annual Earning Assessment (AEAP)		CPUC Decisions	1,895	0	3,915
Low Emission Vehicle (LEV)	PUC Section 740.3 & 740.8	CPUC Decisions	0	0	41,193
Haz Substance Mechanism (HSM)		CPUC Decisions	49,805	85	79
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	0	12,066
Core Pricing Flexibility Program		CPUC Decisions	0	0	1,391
Non core competitive load growth program		CPUC Decisions	0	0	622
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	(3,637)	(4,707)	21,911
CPUC Fee	PUC Section 431	Resolution M-4816	4,390	0	0
Franchise Fees & Uncollectibles	PUC Section 6231	CPUC Decisions	10,477	0	0
Franchise Fee Surcharge (G-SUR)	PUC Sections 6350-6354	CPUC Resolutions	8,728	2,156	21,975
AB 32 Cap-And-Trade			5,223	573	4,536
Public Purpose Program Surcharges Total	PUC Sections 399.8, 890-900	CPUC Decisions	**275,079**	**32,523**	**332,206**
Energy Efficiency (EE) Programs	PUC Sections 739.1, 890-900, 2790	CPUC Decisions	94,582	2,443	85,572
Low Income Energy Efficiency (LIEE)	PUC Sections 740, 890-900	CPUC Decisions	80,517	11,340	132,417
Public Interest RD&D and State Board of Equalization (BOE)	PUC Sections 739.1 & .2, 890-900	CPUC Decisions	11,689	1,264	14,190
Calif Alternate Rates for Energy (CARE) Program			88,291	17,476	100,028
GAS TOTAL			**4,789,682**	**562,023**	**4,095,158**

Appendix B (cont.)

2015 Revenue Requirements ($000)

	Federal/State Mandate	CPUC Mandate	PG&E	SDG&E	SoCalGas
Core Procurement Total			**1,298,757**	**131,006**	**951,033**
Core Gas Supply Portfolio		CPUC Decisions	958,172	131,006	943,783
Other		CPUC Decisions	331,551	0	0
10/20 Winter Gas Savings		CPUC Resolutions	0	0	0
Core Gas Hedging		Report	7,636	0	0
Incentive Mechanism		Report	1,398	0	7,250
Transportation Total			**2,500,926**	**378,037**	**2,511,953**
Distribution		CPUC Decisions	2,013,714	337,929	2,187,256
Transmission		CPUC Decisions	453,878	0	0
Advanced Metering Infrastructure		Report	14,793	0	115,600
Smart Meter			0	0	0
Self Gen Inc Prog (SGIP)	PUC Section 379.6 (a)	CPUC Decisions	6,525	788	8,137
Climate Smart			0	0	0
Calif Solar Initiative (CSI)		CPUC Decisions	5,211	1,926	0
Annual Earning Assessment (AEAP)		CPUC Decisions	7,119	0	5,599
Low Emission Vehicle (LEV)	PUC Section 740.3 & 740.8	CPUC Decisions	0	0	41,872
Haz Substance Mechanism (HSM)		CPUC Decisions	46,555	1,406	2,760
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	0	10,213
Core Pricing Flexibility Program		CPUC Decisions	0	0	974
Non core competitive load growth program		CPUC Decisions	0	0	391
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	(14,524)	20,654	29,475
CPUC Fee	PUC Section 431	Resolution M-4816	3,210	0	0
Franchise Fees & Uncollectibles	PUC Section 6231	CPUC Decisions	9,794	0	0
Franchise Fee Surcharge (G-SUR)	PUC Sections 6350-6354	CPUC Resolutions	13,426	1,977	34,204
AB 32 Cap-And-Trade			2,771	(387)	10,684
Public Purpose Program Surcharges Total	PUC Sections 399.8, 890-900	CPUC Decisions	**271,726**	**34,753**	**363,588**
Energy Efficiency (EE) Programs	PUC Sections 739.1, 890-900, 2790	CPUC Decisions	88,142	(573)	81,770
Low Income Energy Efficiency (LIEE)	PUC Sections 740, 890-900	CPUC Decisions	76,324	15,110	132,417
Public Interest RD&D and State Board of Equalization (BOE)	PUC Sections 739.1 & .2, 890-900	CPUC Decisions	11,094	1,554	13,672
Calif Alternate Rates for Energy (CARE) Program			96,166	18,662	135,729
GAS TOTAL			**4,071,409**	**543,796**	**3,826,574**