California Public Utilities Commission

Electric and Gas Utility Cost Report

Public Utilities Code Section 747 Report to the Governor and Legislature

April 2012

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Figures and Tables

Figures and Tables (cont.)

I. Introduction

Enacted as AB 67 in 2005, PU Code 747 (b) requires the California Public Utilities Commission (CPUC or the Commission) to prepare a written report on the costs of programs and activities conducted by the four major electric and gas companies regulated by the Commission. This legislation was enacted in part to determine the effect of various legislative and administrative mandates, and because rates did not decrease as much as expected after the imposition of charges to address the energy crisis of 2000 and 2001.

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 commission and its annual cost to ratepayers.
3) Energy purchase contract costs and bond-related costs incurred pursuant to Division 27 of the Water Code.
4) All other aggregated categories of costs currently recovered in retail rates as determined by the commission.

This report is submitted by the Commission to fulfill these statutory requirements.

Background

The State of California has been a national leader in electric and gas energy policy, setting innovative mandates for renewable energy, demand side management, and greenhouse gas 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. 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.

Similar to the 2010 AB 67 Report, this report provides a detailed narrative of various energy policies in California to provide the context necessary to understand what drives electric and gas rates. The report presents a breakdown of the major components that contribute to electric and gas rates, with charts and tables showing how these costs and rates have varied since 2003.

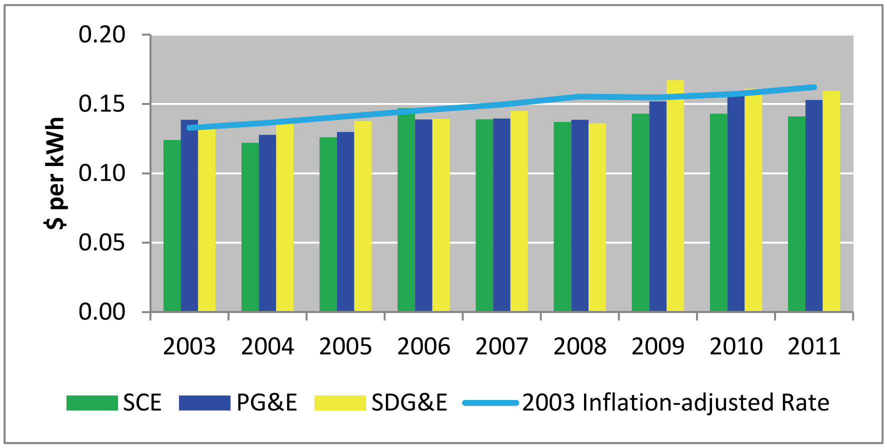
The Report presents an analysis of the authorized revenue requirements for the four major California investor-owned utilities: Pacific Gas & Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E) and Southern California Gas Company (SoCalGas). "Authorized revenue requirements" are the revenues that the utilities are authorized to collect from customers. Using sales forecasts, rates are then set to collect the authorized revenue requirements. To the extent that actual sales differ from forecasted sales, the utilities may collect more or less than the authorized revenue requirements. 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 "true-up" ensures that the utilities only collect their authorized revenue requirements.

Overview

Electric Utility Costs

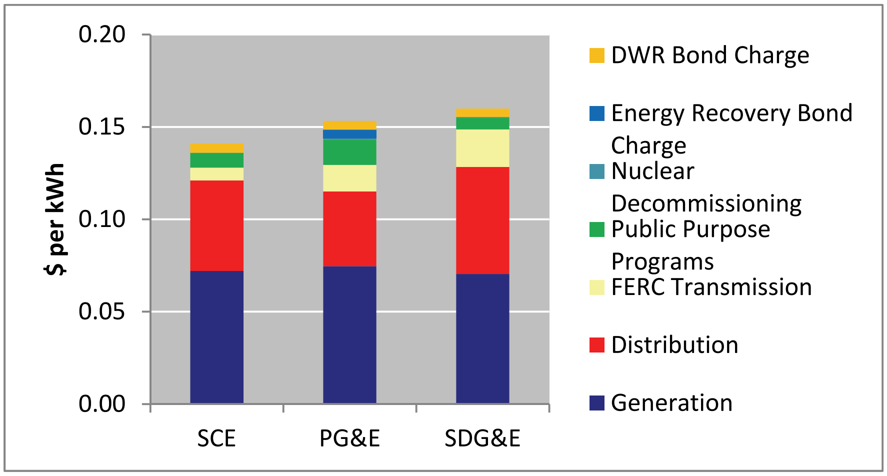
- **System average rate increases have roughly tracked inflation.** Between 2003 and 2011, system average rates have increased at an annual average of approximately 1.6%, compared with an average annual inflation rate of 2.5%. Figure 1.1 shows the trend in average electric rates for SCE, PG&E, and SDG&E. In 2011, SCE's system average rate was 14.1¢/kWh PG&E's was 15.3¢/kWh, and SDG&E's was 16.0¢/kWh.[1]

Figure 1.1: Trends in Average Rates



- **Electric generation and energy procurement are a large component of electric rates.** Generation, provided through utility owned generation and purchased power sources, collectively accounts for approximately 47% of the utilities' electric rates**.**

Figure 1.2: 2011 Rate Components



[1] See SCE Advice Letter 2526-E-A (effective 6/1/11); PG&E Advice Letter 3797-E (effective 3/1/11); and SDG&E Advice Letter 2280-E (effective 9/1/2011).

- **Demand side management has been a cost effective method to meet new demand.** Demand response and energy efficiency programs provide ratepayer savings that are greater than the program costs. Based on reported benefits for 2010, energy efficiency savings alone exceeded costs by over $800 million (see Table 1.3). Savings result from avoided energy procurement and capacity costs, as well as deferred investments in the transmission and distribution systems. In addition to energy efficiency and demand response, the CPUC has several distributed generation demand side management programs as well, including the California Solar Initiative (CSI) program and the Self-Generation Incentive Program (SGIP).

Table 1.3: 2010 Energy Efficiency Utility Reported Costs and Benefits (000)

	PG&E	SCE	SDG&E
Benefits	$1,000,598	$941,643	$148,629
Costs*	$662,221	$514,233	$100,104
Net Benefits	$338,377	$427,410	$48,525

*Includes program costs and costs to participants.

- **Renewable Portfolio Standard (RPS) eligible energy remains a small but growing component of the revenue requirements.** PG&E, SCE, and SDG&E collectively served 20% of their retail electricity load with renewable power in 2011. Since 2003, 2,541 MW of new renewable capacity has been installed as a result of the RPS program. More projects – over 1,000 MW – have come online since 2003 under short-term contracts, but the RPS program is not generally credited with incenting the development of these projects. In total, the CPUC has approved 189 renewable energy contracts for over 17,000 MW of renewable capacity. The CPUC approved 44 contracts for 2,461 MW in 2011.

Gas Utility Costs

- **Total natural gas utility costs in 2011 were at their lowest level in the last 5 years, having decreased significantly from last year,** due to the continued drop in the price of the natural gas commodity. Natural gas procurement costs were 40% lower in 2011 than in 2007.
- **Revenue requirements for natural gas transmission, distribution and storage systems have only increased by 9% since 2007**.
- **Costs authorized by the CPUC for natural gas public purpose programs have increased 59% since 2007,** primarily due to significant increases for the energy efficiency and low-income energy efficiency programs and the California Alternate Rates for Energy (CARE) subsidy**.**

The remainder of this report provides a breakdown of the various electric and gas revenue requirement components and identifies those components that have experienced the greatest increase. In addition to the detailed summary tables provided throughout the text, Appendix A provides summaries of the investor owned utility (IOU) revenue requirements organized by the rate components typically shown on customer bills. Appendix A revenue requirements include balancing account adjustments – the remainder of this report discusses authorized revenue requirements without these adjustments.

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) at the CPUC.
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 where 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.
4. Specific program area proceedings where the program budget is determined.

The utilities earn a rate of return or profit only on costs that are capitalized (e.g. assets and equipment). For many cost categories, such as purchased power and fuel, there is no mark-up or profit – the utilities are only reimbursed for their costs. These are commonly referred to as pass-through costs.

Categorization of Utility Costs

Utility costs or revenue requirements fall into three major categories: generation, distribution, and transmission. This categorization not only reflects major areas of utility operations, but it is also used to determine what portion 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. These customers may generate their own power on site or buy power from a non-utility source (e.g., an electric service provider, or ESP, or a community choice aggregator). These customers do not typically pay generation costs and instead pay only transmission and distribution costs; however, in some cases, these customers are required to pay non-bypassable charges for generation procured on their behalf before they departed from bundled service. Additionally, some large customers receive service at transmission voltage levels and are not charged for use of the utility distribution system.

Table 1.4: 2011 IOU Revenue Requirement Summary (000)

	PG&E	SCE	SDG&E
Generation/Energy Procurement			
Purchased Power	$3,480,995	$3,924,933	$840,931
Utility Owned Generation	$1,992,406	$1,891,421	$391,097
Distribution[2]	$3,643,232	$4,033,531	$1,118,021
Transmission	$1,265,194	$635,970	$409,100
Demand Side Management & Customer Programs	$582,483	$675,729	$162,829
Bonds & Fees	$957,416	$499,271	$120,622
Total 2011 Revenue Requirement	**$11,921,727**	**$11,660,856**	**$3,042,600**

[2] Distribution line item includes taxes.

Rate Base

The rate base is the book value, after depreciation, of the generation, distribution and transmission infrastructure owned and operated by the utility. Utilities earn a regulated rate of return on their rate base. Other things being equal, a larger rate base results in higher net income for the utilities (and vice versa). As assets are depreciated over time, the rate base declines. Rate base increases when utilities build new plant and infrastructure or make capital additions and improvements. Changes in rate base also result in changes in the depreciation allowance utilities are authorized to collect. Between 2003 and 2011, the utilities' rate base increased from $22 billion to $39 billion, leading to increases in GRC revenue requirements.

Figure 1.5: 2011 Rate Base

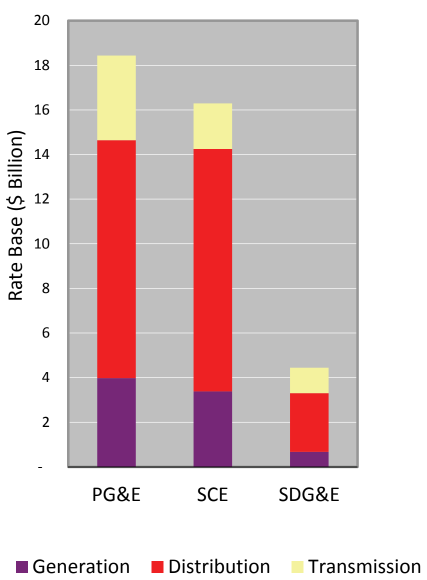
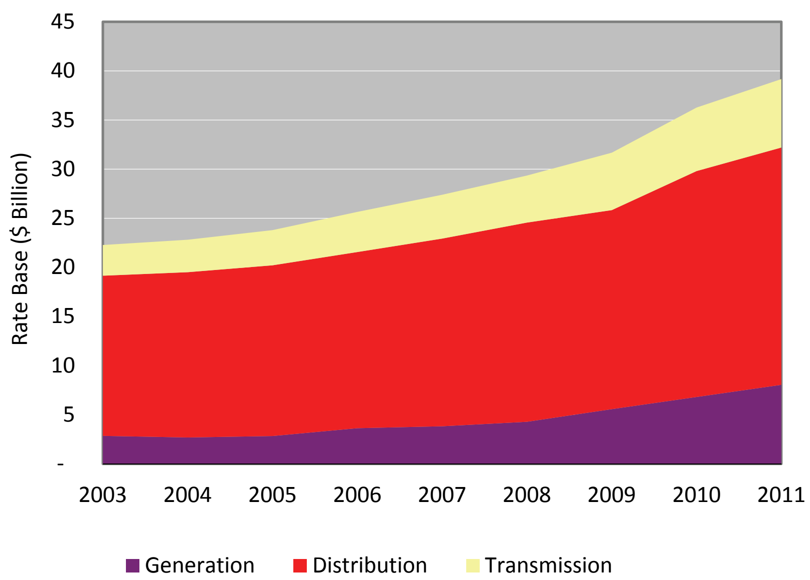


Figure 1.6: Trends in Rate Base



II. General Rate Case Revenue Requirements

Costs that utilities can forecast with reasonable accuracy are examined and approved by the Commission in GRC proceedings. These proceedings are usually on a three year cycle for the major utilities, although the interval may occasionally be longer than three years. In the GRC proceedings, the Commission sets a pre-specified revenue requirement for the first year, called the "test year," with formulaic adjustments for the following years (commonly called attrition years) until the next GRC decision takes effect.

The utilities' authorized revenue requirements typically remain the same even if the utilities spend more or less than adopted by the Commission. GRC ratemaking with pre-specified budgets is aimed at providing the utilities with an incentive to stay within approved budgets. Under this ratemaking treatment, utility profits decline if spending is higher than the GRC authorized revenue requirement, and vice versa.

Approximately 54% of the utilities' revenue requirements are set in general rate cases at the CPUC and FERC. The remaining 46% consists of pass-through costs determined to be reasonable by the CPUC. The transmission revenue requirement determined by FERC in transmission owner rate cases follows similar test year ratemaking treatment.

GRC revenue requirements are generally categorized as Distribution Revenue Requirements, Utility Owned Generation (UOG) Revenue Requirements, and Transmission Revenue Requirements. Each of these categories is comprised of the following major cost elements: operations and maintenance (O&M), depreciation, return on rate base and taxes. Table 2.1 below summarizes the total CPUC-jurisdictional GRC revenue requirements broken down into these cost categories for the three major electric utilities.

Table 2.1: 2011 General Rate Case Revenue Requirements[3] (000)

	PG&E	SCE	SDG&E
Operations and Maintenance	$2,552,914	$2,018,908	$540,646
Depreciation	$1,160,930	$1,369,403	$340,544
Return on Rate Base	$909,993	$1,246,887	$252,192
Taxes	$647,306	$859,233	$222,377
Total	**$5,271,142**	**$5,494,431**	**$1,355,759**

(Excludes FERC determined transmission revenue requirements.)

- **O&M:** These costs include all labor and non-labor expenses for utility operation and maintenance of generation plants and the distribution system. The utilities are required to maintain their systems in accordance with the Commission's safety and reliability standards and industry best practices, but the Commission does not typically dictate how the utilities spend O&M funds. Depending on how the utilities manage various projects and prioritize their budgets, they may spend more or less than the Commission's authorized O&M budget.

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

In the GRC proceedings, the Commission undertakes a thorough review of O&M separately for generation and distribution related facilities and for general plant.

- **Depreciation:** Capital investment in utility facilities and assets is financed by the utilities using their own funding sources. The capital used to finance these assets is returned over specified time periods in the form of a depreciation allowance. Depreciation spreads the ratepayers' cost of the physical electric plant and systems over its useful life.
- **Return on Rate Base:** Because the utilities provide the upfront financing for all capitalized expenditures, the Commission authorizes a rate of return on the invested capital. The rate of return is the weighted average cost of debt and shareholder equity. The Commission allows a fair and reasonable return sufficient to allow the utilities to obtain financing. The rate of return was formerly determined in each utility's GRC, but today the Commission conducts a separate cost of capital proceeding to determine the rate of return for the major energy utilities. The utilities' actual rate of return may be more or less than the rate of return authorized by the Commission, depending on how well the utilities manage their operations and costs. If the utilities keep costs below their authorized revenues, actual rates of return will exceed authorized levels, and vice versa.

In addition to the authorized rate of return, the Commission has instituted some incentive programs such as the energy efficiency Risk/Reward Incentive Mechanism (RRIM) and the Gas Cost Incentive Mechanism (GCIM), whereby the utilities share the savings or cost reductions with ratepayers. The utilities do not earn a return on purchased power and fuel expenditures, which, as noted previously, are pass-through costs reviewed in ERRA proceedings.

Distribution Revenue Requirements

Since 2003, the total distribution revenue requirement, excluding franchise fees and taxes, has increased from $4.8 billion to $7.1 billion. Over the same time period, depreciation expenses have experienced the greatest increase, with a 9.9% average annual growth rate. O&M and return on rate base have increased annually by 3.6% and 2.9%, respectively. The increases in distribution costs are primarily due to capital additions and infrastructure improvements to the distribution system. These distribution infrastructure investments have increased rate base, as discussed on page 9.

Figure 2.2: Trends in Distribution Revenue Requirement

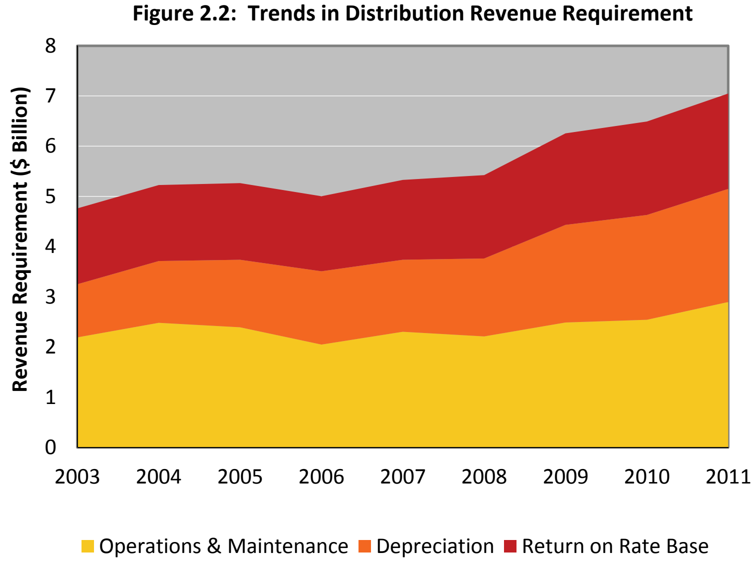


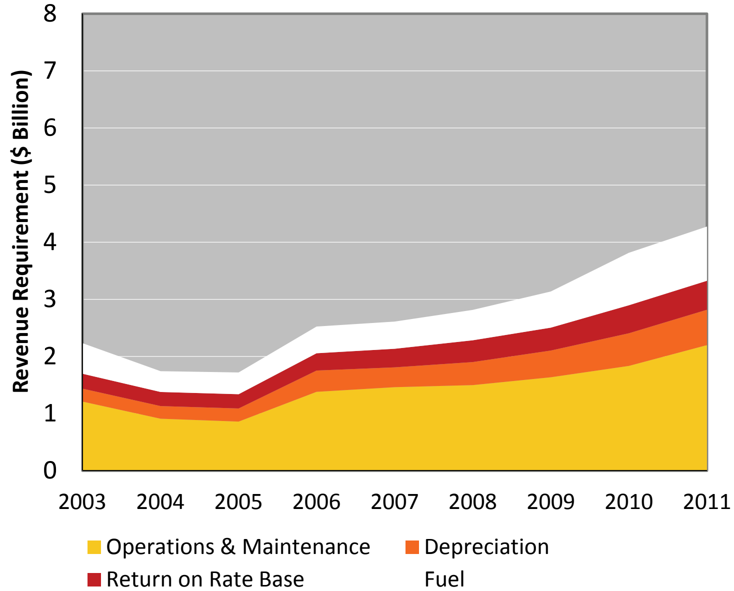
Table 2.3: 2011 Distribution Revenue Requirements (000)

	PG&E	SCE	SDG&E
Operations and Maintenance	$1,337,023	$1,169,848	$406,132
Depreciation	$905,514	$1,053,933	$292,292
Return on Rate Base	$753,390	$950,517	$197,220
Total	**$2,995,926**	**$3,174,298**	**$895,644**

Utility Owned Generation Revenue Requirements

The revenue requirement for utility owned generation (UOG) includes O&M costs, depreciation and return on rate base related to these facilities. As older generating plants depreciate, costs decrease over time unless new plants are built by the utilities or capital improvements are made to existing facilities. The UOG revenue requirement increased recently due to nuclear steam generator replacements by SCE and PG&E and additions of new UOG peaking capacity. In 2006, some administrative and general expenses were recategorized as generation expenses in the GRC. Because of this, O&M expenses for generation increased in 2006 and decreased for distribution.

Figure 2.4: Trends in Generation Revenue Requirement



*Fuel inclued to show total utility owned generation cost but not part

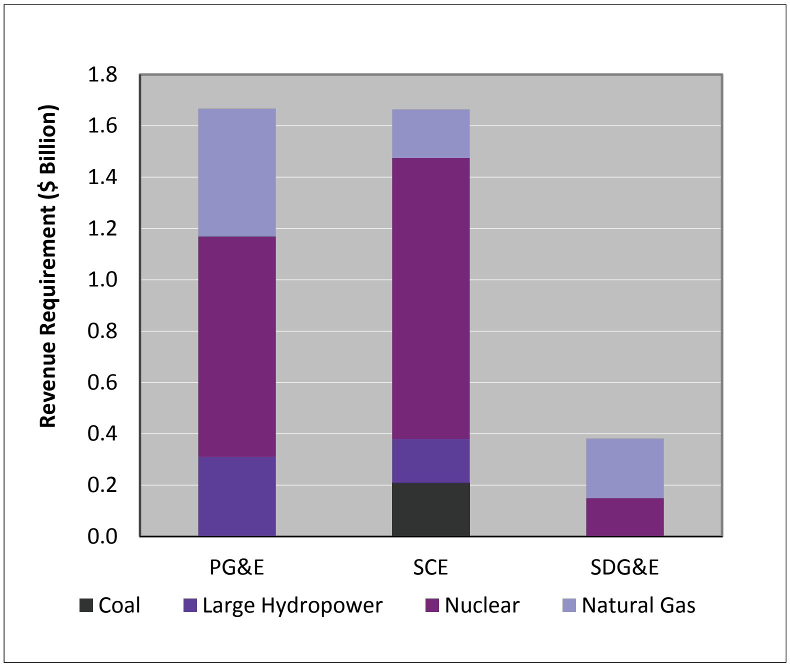
While the majority of UOG revenue requirements are authorized in the GRC, fuel costs are authorized annually through ERRA proceedings because fuel prices fluctuate with the market. Following restructuring and divestiture of fossil-fueled generation, UOG (including fuel costs) now accounts for approximately 34% of the combined utility supply portfolio and approximately 16% of their combined revenue requirements.

Table 2.5 2011 Generation Revenue Requirements (000)

	PG&E	SCE	SDG&E
Operations and Maintenance	$1,215,891	$849,059	$134,514
Depreciation	$255,416	$315,469	$48,252
Return on Rate Base	$156,603	$296,371	$54,972
Total	**$1,627,910**	**$1,460,899**	**$237,738**

PG&E's UOG consists primarily of hydro-electric, nuclear power (Diablo Canyon), and an increasing number of natural gas plants (e.g., PG&E's 660 MW Colusa Generation Station). SCE's UOG portfolio consists primarily of nuclear, coal (with a joint ownership stake in Four Corners Generating Facility in Arizona), and natural gas power plants, including the 1,035 MW Mountainview Power Plant and peakers. SCE's reliance on coal has substantially decreased since the Mohave Generating Station was taken out of service.[4] SDG&E's UOG includes nuclear and two natural gas plants: the 565 MW Palomar Energy Center and the 48 MW Miramar Energy Facility.[5]

Figure 2.6: 2011 Revenue Requirements of UOG Sources



SCE and SDG&E also hold joint ownership in San Onofre Nuclear Generating Station (SONGS), and SCE holds partial ownership in Palo Verde Nuclear Generating Station in Arizona.[6] Due to capital investment in new steam generators, nuclear generation revenue requirements have increased steadily, at an average annual increase of approximately 4% per year.

The utilities divested most of their natural gas generation capacity in 1998, but have recently acquired a number of natural gas plants, which have resulted in increases in UOG revenue requirements.

[4] In addition, the Commission approved SCE's sale of its stake in the Four Corners plant in March 2012.
[5] The plants discussed in this section include only those that the utilities planned to use in 2011.
[6] 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.

Besides the O&M, depreciation and return 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:[7]

- **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 lives.

Authorized Rate of Return

Figure 2.7 shows the weighted average rate of return authorized by the Commission since 2003 for each utility. The rate of return is the weighted average cost of debt and shareholder equity. This figure does not include the rate of return authorized by the FERC for IOU transmission systems – it only includes return authorized by the CPUC for utility owned generation and distribution. The weighted average rate of return has declined from 2003 to 2011, driven mostly by the lower cost of debt in the last few years. Figure 2.8 shows the trends in the equity component of the rate or return. The utilities will file applications to update their authorized rate of return in 2012.

Figure 2.7: Trends in Weighted Average Rate of Return

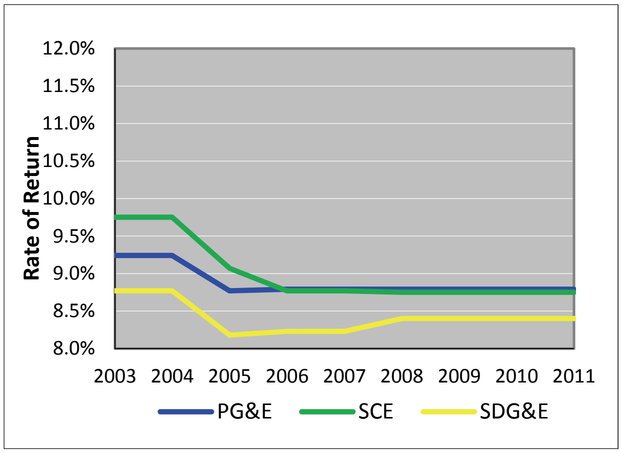
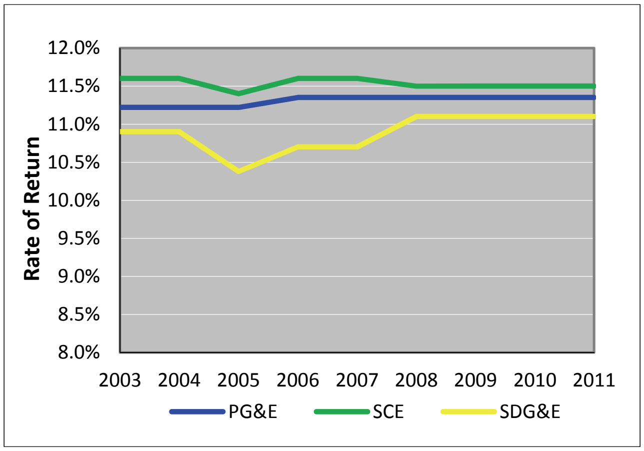


Figure 2.8: Trends in Return on Equity



Transmission Revenue Requirements

As part of energy restructuring, the California Independent System Operator (CAISO) was created and given operational control over the utilities' high voltage transmission lines on January

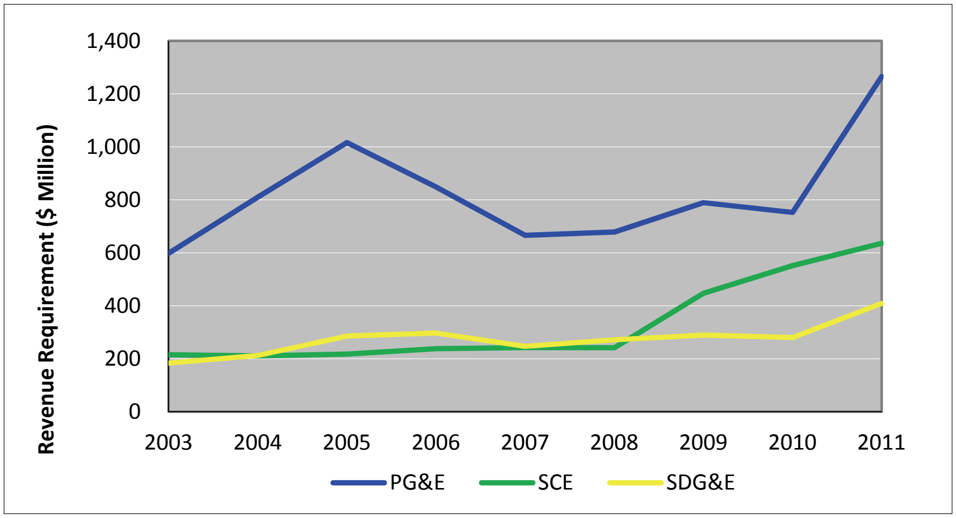
[7] Nuclear Decommissioning and DOE Decommissioning & Disposal expenses are categorized with Bonds & Fees because they are collected separately.

1, 1998, and authority for determining transmission revenue requirements was transferred to FERC. 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.

Transmission revenue requirements vary significantly among the utilities. One factor is that each utility defines its high voltage transmission lines differently. PG&E, SDG&E, and SCE define all power lines at and above 60kV, 69kV, and 200kV, respectively, as transmission. For this reason, transmission constitutes a larger percentage of PG&E and SDG&E's costs than SCE's.

Transmission revenue requirements for the three utilities have experienced varied annual growth rates since 2003. PG&E's transmission revenue requirement has increased at a 9.8% annual average rate, SCE's at 14.5%, and SDG&E's at 10.5%.[8]

Figure 2.9: Trends in Transmission Revenue Requirements[9]



[8] Includes Transmission Owner Ratecase Revenues, Reliability Services, Transmission Access Charges (TAC) and CWIP (SCE only).

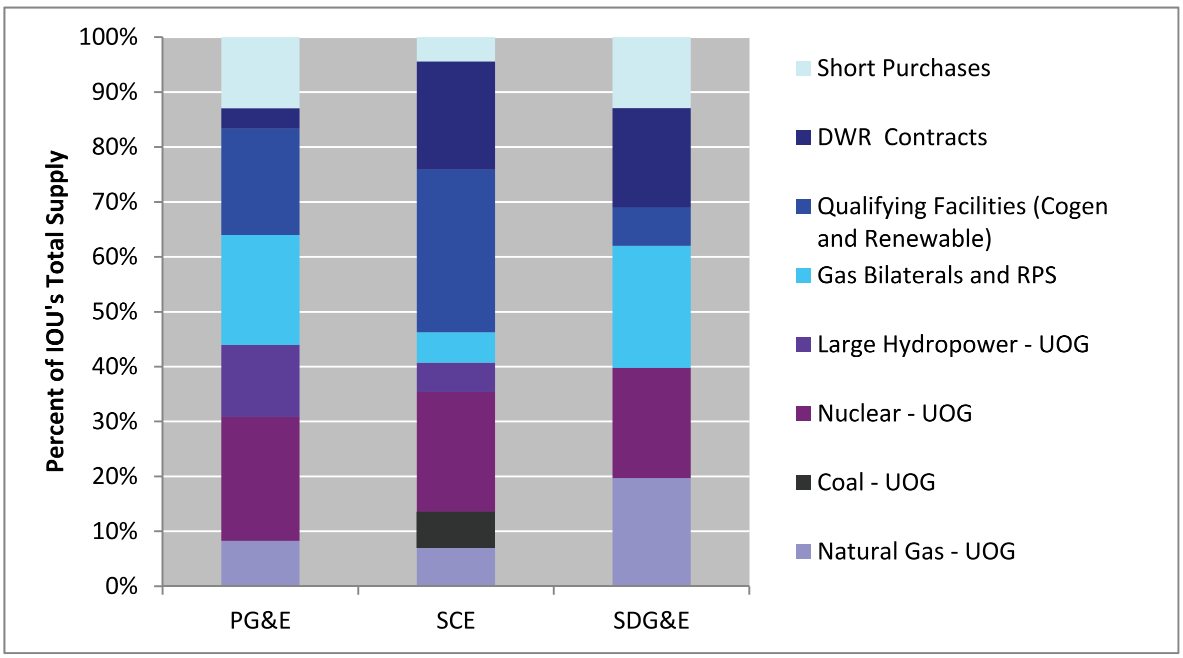
[9] Reliability Services was the largest contributor to the 2005 spike, which was due to intra-zonal congestion costs incurred in 2004. See CAISO 2005 Annual Report, April 2006, pp. 6-5 to 6-7. Retrieved from: http://www.caiso.com/17d5/17d59ec745320.pdf.

III. Power Procurement Costs

The generation revenue requirement includes the UOG revenue requirement discussed in Chapter 2, as well as purchased energy and capacity costs. As previously noted, the utilities divested almost all of their fossil fueled generating plants during restructuring in the late1990s and had been relying primarily on purchased power for incremental electricity needs, although this has begun to change in recent years with the expiration of power contracts and the acquisition of new utility-owned natural gas plants.

In 2011, purchased power accounted for 66% of the total generation revenue requirement while the utility owned generation revenue requirement comprised about 34%. Power purchase costs represent the largest component of generation costs and accounted for 31% of total revenue requirements. Recovery of these costs is authorized through ERRA proceedings and not through GRCs, and there is no mark-up or profit for the utilities on purchased power expenses.

Figure 3.1: 2011 Energy Supply



Background

Heavy reliance on power purchases rather than utility owned power plants began with the enactment of AB 1890, 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 generation market, the utilities were encouraged to divest at least 50% of their fossil generation. The CPUC provided a rate of return 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 highly exposed to spiking 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 Commission 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 Commission required the IOUs to create.

AB 380 (2005) further addressed Commission responsibilities for resource planning, requiring the Commission, 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.

Following the energy crisis, the CAISO redesigned its market structure and rules. The redesigned system, the Market Redesign and Technology Upgrade (MRTU), went operational in the spring of 2009. With MRTU, the market price is determined using many (approximately 3,000) dispersed locations or nodes instead of the earlier zonal pricing system. It also established local market power mitigation in areas with constrained transmission capacity. These changes were aimed at making the electricity market more efficient by accurately and transparently pricing generation and by prioritizing and optimizing generation siting and/or transmission upgrades.

Types of Purchased Power

DWR Contracts

DWR contracts are 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 Commission 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 of these contracts, DWR's revenue requirement for PG&E was negative in 2011 and resulted in a refund of operating reserves to PG&E customers. The majority of the contracts will expire by the end of 2012. As discussed further below, there is also a DWR bond charge that is collected separately in electric rates.

Qualifying Facilities (QFs)

QFs are 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 terminates the "must take" obligation for QFs over 20 MW and establishes new energy prices for QFs.[10]

Figures 3.2 and 3.3 break out QF supply and revenue requirements for cogeneration and renewable energy. The renewable energy supply meets the requirements for the Renewable Portfolio Standard. The total energy supply provided by all QFs, cogeneration and renewable, has decreased by about 15% since 2003 as older contracts expire, and the QF revenue requirement has decreased by approximately 18% since 2003.

Figure 3.2: Trends in Purchased Power Revenue Requirements

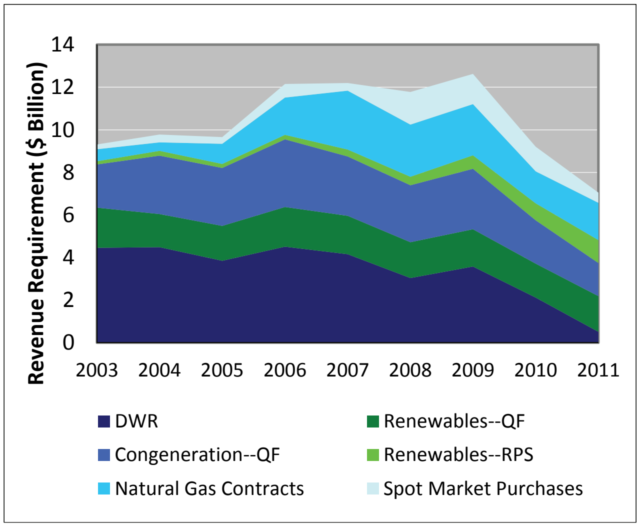
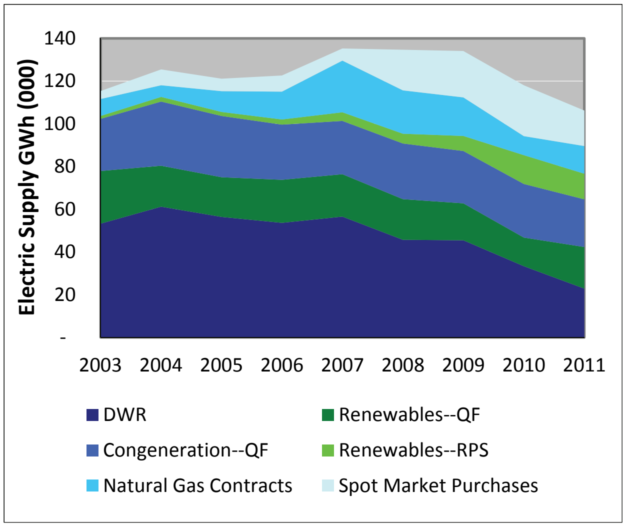


Figure 3.3: Trends in Purchased Power Supply (GWh)



Bilateral Contracts and Capacity Contracts

Bilateral contracts are the standard method for new energy procurement today. These contracts are entered into directly between the utility and an independent power supplier, which may be a generator or a trader. The utilities 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 15-17% planning reserve margin for generating capacity. Capacity contracts pay generators to be available to produce power and ensure that sufficient capacity is

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

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 bilateral contracts include long-term contracts and capacity contracts, bilateral contracts cost considerably more than spot market purchases or short-term contracts. The revenue requirements from bilateral contracts have increased over 15% annually, and the average cost (¢/kWh) for bilateral contracts has increased by 8.4%.[11]

There are a few factors that help to explain this trend. First, in 2004, Commission 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. The capacity 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 very 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, a significant amount of electric capacity is only needed for a few peak hours each year, as approximately 10 percent of electric demand occurs for less than 150 hours per year. Natural gas fueled generation is often the resource best able to supply peaking capacity. 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. Increased use of wind and solar generation increases the need for peaking capacity to fill in when, due to weather, wind and solar resources are producing less energy.

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 2008, Governor Schwarzenegger expanded the RPS program by Executive Order, raising the renewables goal to 33% of the state's energy requirements by 2020. In 2011, SB 2 codified the 33% renewables target.

The RPS mandate has made renewable energy central to the state's core procurement planning. However, renewable energy revenue requirements remain a relatively minor component in the total revenue requirement at present, 10.4% in 2011.[12] QFs contracts comprise the majority of the RPS-eligible resources that are currently supplying the utilities, while new RPS-eligible resources are now generally procured through competitive contracts. In 2011, the average cost of renewable energy, including QFs, remains above the average cost for the total energy portfolio, as seen in Figure 3.4.

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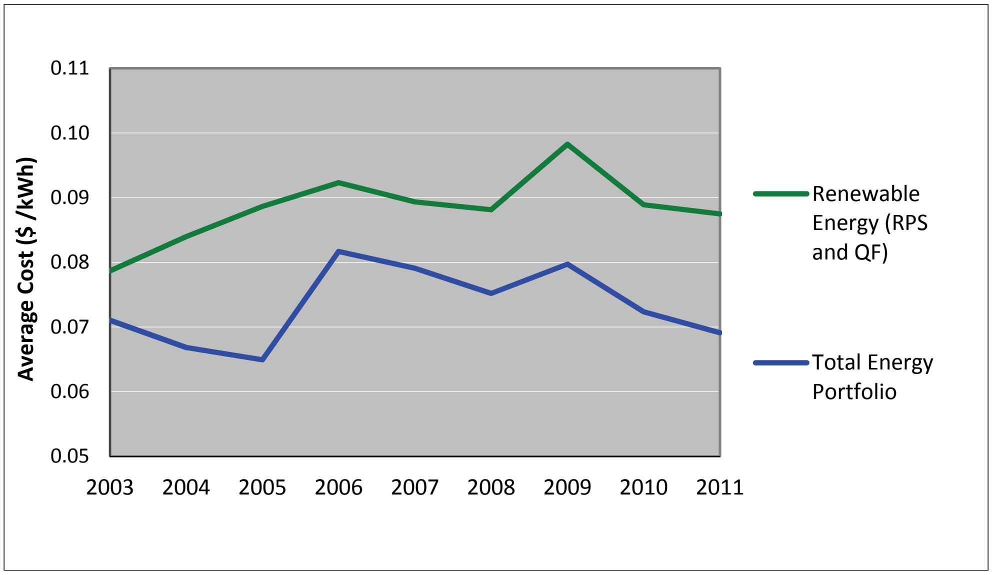
[11] Bilaterals represent natural gas contracts only.
[12] Renewable energy includes RPS and QFs.

Figure 3.4: Average Cost of RPS Sources and Total Energy Portfolio



The costs for renewable contracts approved by the Commission are higher than delivered costs. According to a recent report, the average renewable contract costs have increased from 5.4 cents per kWh in 2003 to 13.3 cents per kWh in 2011. One important reason for this increase is that the IOUs contracted with existing renewable facilities at the beginning of the RPS program and with mostly newer facilities, with higher upfront capital costs, in later years. However, bids from the 2011 RPS Solicitation show significantly lower costs than bids in the past few years, which will be reflected in future IOU contracts.[13]

Other Power Purchases

There are additional power purchase mechanisms to ensure that the utilities have secured sufficient capacity to balance load across the grid and meet peak load requirements. These include both sales and purchases, which accounted for 5.6% (net) of the power purchase revenue requirement in 2011.[14]

- **Spot Market Purchases:** The term spot market purchases broadly refers to power that the utilities buy from the CAISO's Day-Ahead and Hour-Ahead markets 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. Spot market purchases accounted for 5.8% of the power purchase revenue requirement in 2011.

[13] See CPUC, Renewables Portfolio Standard Quarterly Report, 4th Quarter 2011, Cost Reporting in Compliance with SB 863.
[14]Utility options for market transaction are defined in D. 02-10-062. A breakout of margin sales and purchases is confidential/privileged information pursuant to applicable provisions of D.06-06-066, G.O. 66-C and PUC Code Sec. 583 and Sec. 454.5(g).

- **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 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.

Factors Affecting Generation Costs

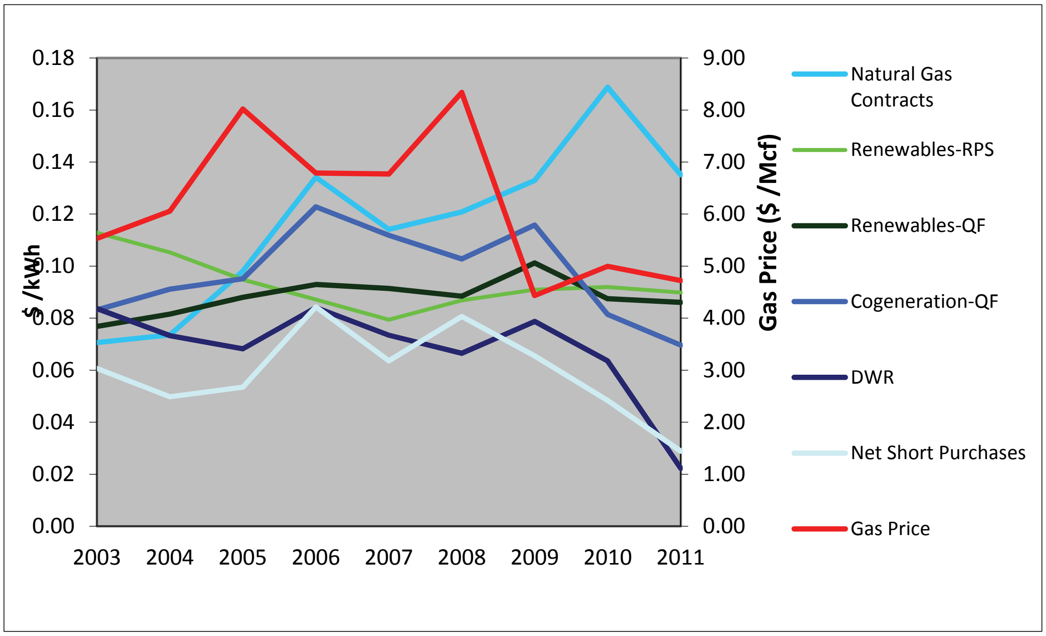
Energy generation and procurement costs can vary significantly over time due to a number of factors. Figure 3.5 shows the average costs of various types of purchased power.

The following factors influence energy costs:

- **Peaking and Firming Capacity**. Peaking and firming generation capacity is typically gas-fired because these units can start and ramp-up quickly. Because peaking capacity is used only over a few peak hours during the year, the cost per kWh can be high. Recently, the utilities have added new peaking capacity to meet overall capacity requirements. As a result, UOG and contracted natural gas-fired generation costs are higher than would otherwise be expected, given recent low gas prices.
- **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, natural gas bilateral contracts, and UOG natural gas generation all experience greater fluctuations than other generation resources. The cost of natural gas-fired generation peaked in 2006, with the spike in gas prices after Hurricane Katrina in 2005, and has shown considerable fluctuation since that time, as shown in Figure 3.5.
- **Bilateral Contracts.** Bilateral contracts can be a higher cost resource because they include capacity contracts and long term contracts, with the supplier attempting to recover all costs of the generating plant through a single contract. In comparison, spot and short term purchases are frequently less expensive because the supplier has an existing resource and is willing to sell at less than full cost to minimize losses. With the lessons learned from the energy crisis, the Commission 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 Commission requires long term resource planning and resource adequacy. The main reason spot market prices are lower is that the utilities are buying very little in the spot market, so there is more supply than demand in the spot market at times.

The higher 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.

Figure 3.5: Average Cost for Purchased Power[15]



- **DWR Costs.** DWR costs have decreased in recent years due to the declining price of gas and, in 2011, because DWR's revenue requirement for PG&E was negative (due to the expiration of power contracts in the service area) and resulted in a refund of operating reserves to PG&E customers.
- **Depreciation Costs.** Older UOG plants cost less now because the utilities have already substantially recovered their investments in these plants. As a result, ratepayers pay less for depreciation and return on these assets. Because UOG hydroelectric, coal and nuclear plants are older, they cost between $0.032 and $0.056/kWh – less than the cost for new resources.

[15] The average cost for each resource represents both energy and capacity. On an energy-only basis, RPS exceeds Natural Gas by $0.05/kWh in 2011.

IV. Demand Side Management & Customer Programs

Demand Side Management involves various programs and activities on the customer side of the meter to curtail or shift demand for electricity through energy efficiency, demand response, and distributed generation. In 2003, the CPUC and the CEC adopted the Energy Action Plan to establish goals for the state's energy strategy.[16] 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 demand side management primarily consist of financial incentives to encourage demand side management activities, and the administrative costs to manage these programs. In order to achieve the goals established in the Energy Action Plan, spending on demand side management has experienced a 17% average annual increase since 2003, as CSI and demand response programs were initiated, and energy efficiency programs doubled in size. Cost/benefit studies have shown that in total, the collective costs of these programs are less than the financial savings from reducing the demand for generation. In total, demand side management programs combined accounted for 4.5% of the total revenue requirement, however the revenue requirement does not incorporate the energy savings. In 2010, energy efficiency programs alone resulted in over $800 million in reported net savings to ratepayers.[17]

In addition to demand side management, California also mandates customer programs to provide rate discounts and energy efficiency improvements for low-income customers.

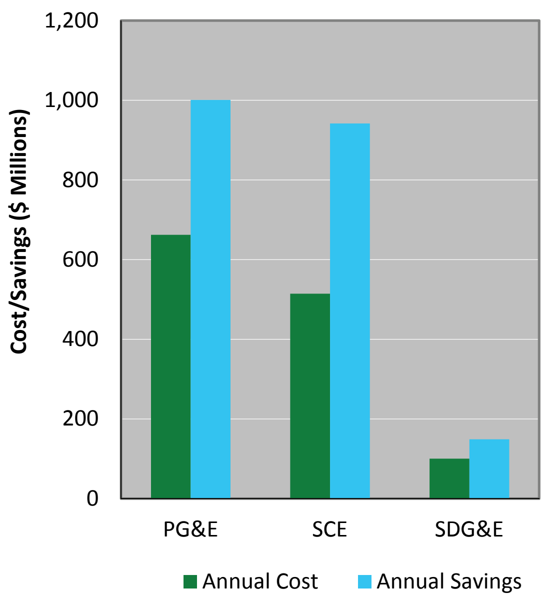
Table 4.1: 2011 Demand Side Management and Customer Program Costs (000)

	PG&E	SCE	SDG&E	Total
Energy Efficiency: Public Goods Charge	$120,670	$100,415	$35,640	$256,725
Energy Efficiency: Procurement Charge	$237,616	$297,252	$38,493	$573,361
Demand Response	($12,852)[18]	$71,162	$0	$58,310
California Solar Initiative	$106,077	$110,000	$25,000	$241,077
Self-Generation Incentive Program	$29,823	$28,000	$10,035	$67,858
Total	**$481,334**	**$606,830**	**$109,168**	**$1,197,332**

[16] The Energy Action Plan was updated in 2005 and 2008.
[17] Net Savings based on 2010 utility reported energy efficiency savings and costs.
[18] This includes demand response program costs of $67 million and an $80 million decrease because of a reduction in funding for PG&E's SmartAC Program.

Energy Efficiency

Figure 4.2: Annual Utility Reported Costs and Savings for 2010 Energy Efficiency Programs



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 Commission translated this policy into specific annual and cumulative numerical goals for electricity and natural gas savings by utility service territory. These goals are updated periodically by the Commission as provided for in that decision. The Commission-adopted energy savings goals are expressed in terms of annual and cumulative gigawatt hours (GWh), million-therms (MMtherms) and peak megawatt (MW) load reductions.

Prior to 2006, energy efficiency programs had largely been funded by the Public Goods Charge (PGC) as authorized by Public Utilities (PU) Code Sections 381 and 399. In addition to the energy efficiency budget supported by the Public Goods Charge, additional funds for energy efficiency programs are also collected through the procurement component of rates. As a result, the aggregated annual budget for energy efficiency programs increased from $283 million in 2003 to $830 million in 2011.

The Commission's 2006-2009 energy efficiency funding supported programs and activities that generated annual energy savings of 9,812 GWh, 1,717 MW and 112 MMtherms for ratepayers.[19] Approximately 60 percent of those savings would not have occurred without program intervention. The net benefits over the life of these installed technologies and actions were estimated at $2.8 billion for the 2006-2008 period and an additional $1.5 billion in 2009. The estimated cost effectiveness (Total Resource Cost – TRC) ratios were 1.14 and 1.54 respectively for those time periods.[20] In addition to the directly quantifiable savings and benefits, the Commission has also supported programmatic activities targeted at the long term transformation of consumer energy markets through education and training. The Commission has continued to support investments in energy efficiency across all market sectors in the state. The 2010-2012 energy efficiency portfolio of programs was funded at $3.1 billion, and as of January 2012 claimed savings of 4,093 GWh, 755 MW, and 39.9 MMtherms (pending verification and evaluation).[21] Like former programs, these support residential, commercial, industrial and

[19] 2006-2008 Energy Efficiency Evaluation Report - Executive Summary, p. ii; and Energy Efficiency Evaluation Report for the 2009 Bridge Funding Period Executive Summary, p. 4.
[20] Ibid: 2006-2008, p viii; 2009, p. 4.
[21] Current Program Cycle Reported Savings Information (2010-12) at http://eega.cpuc.ca.gov/Default.aspx.

agricultural sectors to overcome barriers to improving energy efficiency and realize savings for the ratepayer.

Demand Response

Demand response 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 signal. Demand response saves 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. Demand response goals are met through customer programs and metering infrastructure upgrades.

- **Demand Response Customer Programs:** These programs are primarily aimed at large commercial and industrial customers that can shed load as an immediate or day ahead response. Customers are provided bill credits or payments to participate in the programs, and customers are called to curtail load on designated peak days. Demand response programs can meet the needs for system reliability or peak capacity management.
- **Advanced Metering Infrastructure (AMI):** The AMI initiative is a statewide effort to upgrade all customers to an electronically integrated network, which enables greater communication and control system technologies to manage energy use. The benefits of AMI are threefold. First, AMI provides price and usage information that helps customers make better informed decisions about energy use, so they can optimize electricity consumption and reduce their bills. Second, AMI lowers the utilities' operating costs by reducing the need for manual meter reading. Third, it allows for faster outage detection and restoration of service by a utility when an outage occurs, resulting in less disruption to customers' homes and businesses. AMI costs are included with the distribution revenue requirements discussed on page 11.[22]

Distributed Generation

Ratepayers fund two distributed generation programs that provide financial incentives to participating customers – CSI and SGIP.

- **California Solar Initiative (CSI):** Established in 2006, CSI provides both up-front payments as well as payments stretched out over the projects' first five years, based on performance, for the installation of photovoltaic solar systems for residential and commercial customers up to 1 MW. The CSI Program has a budget of $2.367 billion over 10 years, and the goal is to reach 1,940 MW of installed solar capacity by the end of 2016. In SDG&E service territory, the CSI program is being implemented by the California Center for Sustainable Energy.

[22] The authorized revenue requirements for AMI were $119.7 million for PG&E, $203.5 million for SCE and $70.6 million for SDG&E in 2011.

- **Self-Generation Incentive Program (SGIP):** Established in 2001, SGIP provides incentives to support existing, new, and emerging distributed energy resources. 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. 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.

A cost/benefit study on the CSI program was issued in April 2011[23] and a cost/benefit study of SGIP was issued in February 2011.[24] The CSI study forecasts that by the program's completion in 2016, declining solar PV installed costs and increasing retail electric rates will make the program cost-effective for many residential customers, even in the absence of CSI program incentives. Overall, installed system costs are a key driver of cost-effectiveness results from both the participant and societal perspectives. The SGIP study concludes that nearly all of the evaluated DG technologies are cost-effective.

Low-Income Programs

IOUs provide two ratepayer-funded programs for low-income customers: CARE rate discounts and the Energy Savings Assistance Program.

Table 4.3: 2011 Low Income Program Costs (000)

	PG&E	SCE	SDG&E	Total
CARE Discount	$725,368	$275,222	$40,357	$1,040,947
CARE Administrative Expenses	$7,695	$5,485	$2,516	$15,696
Energy Savings Assistance Program	$93,454	$63,414	$10,788	$167,656
Total	**$826,517**	**$344,122**	**$53,661**	**$1,224,299**

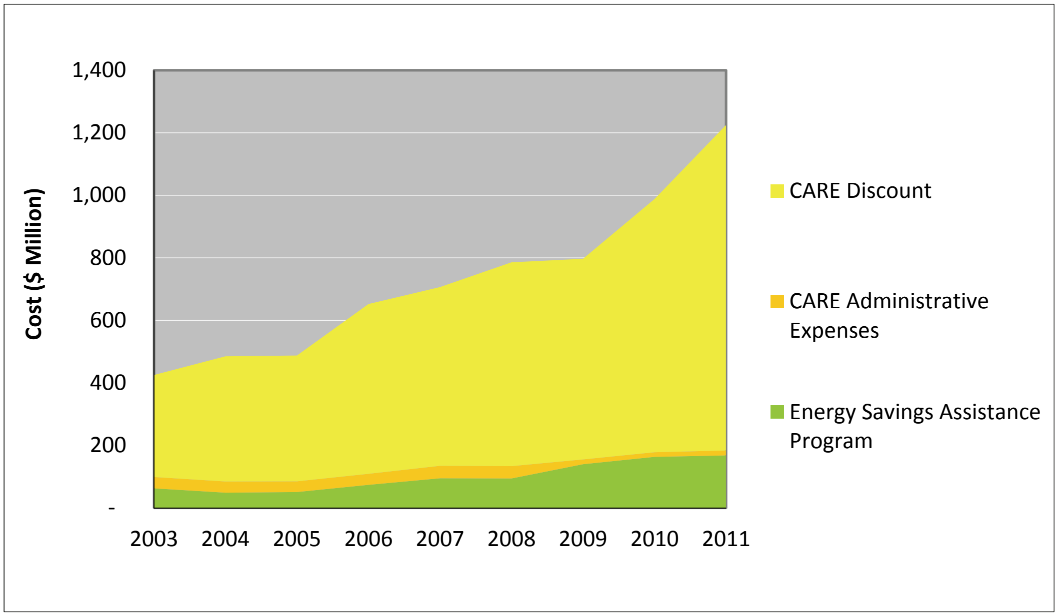
California Alternate Rates for Energy (CARE): The CARE program provides rate discounts for qualifying low-income customers. The minimum CARE rate discount was increased from 15% to 20% by Commission Decision 01-06-010 in 2001. In addition, during the energy crisis, AB 1X exempted CARE customers from certain DWR power costs and kept Tier 1 and Tier 2 residential rates frozen at pre-restructuring levels. Additionally, CARE customers do not have Tier 4 and Tier 5 rates for high consumption levels as non-CARE customers do. As a result, the effective CARE discount increased substantially above 20% for CARE customers with usage above Tier 1 and Tier 2.

CARE costs have two components—CARE program administration cost and the cost of the discount itself. CARE program administration costs total approximately $16 million per year. The CARE discount is a much larger amount and is paid by non-CARE customers. A higher CARE discount does not result in a higher revenue requirement for the utility, but it does increase the rates that non-CARE customers pay. The cost of the PG&E CARE discount in 2011 was $725 million, compared to $275 million for SCE and $40 million for SDG&E. A major reason that PG&E's CARE discount costs more is that PG&E only had Tier 1 and Tier 2 rates for CARE

[23] See ftp://ftp.cpuc.ca.gov/gopher-data/energy_division/csi/CSI%20Report_Complete_E3_Final.pdf.
[24] See http://www.cpuc.ca.gov/NR/rdonlyres/2EB97E1C-348C-4CC4-A3A5-D417B4DDD58F/0/SGIP_CE_Report_Final.pdf

customers for most of 2011 whereas SCE and SDG&E had three tiers, making PG&E's effective CARE discount more substantial at high levels of consumption.[25] The cost of the CARE discount has increased 16% annually since 2003.

Figure 4.4: Trends in Low Income Program Costs



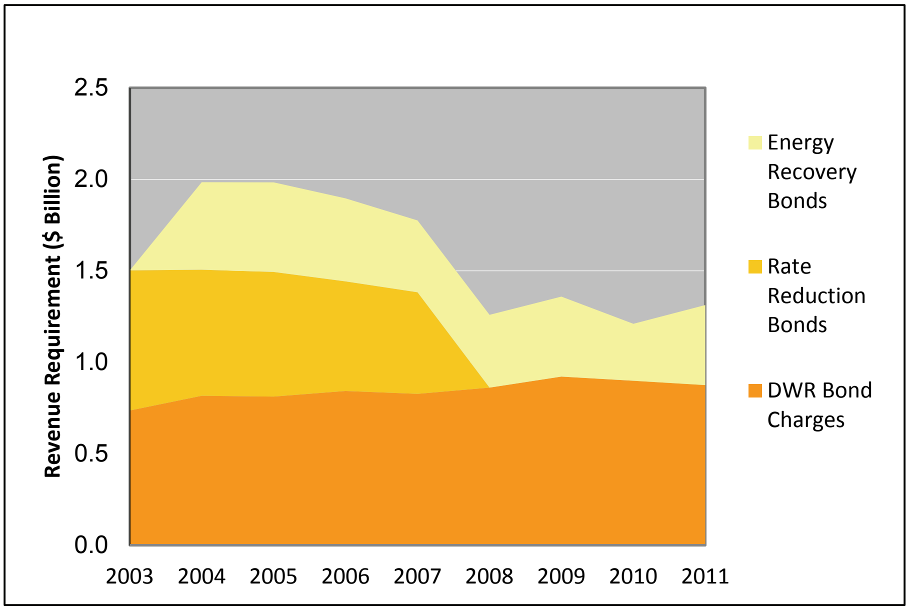
Energy Savings Assistance Program (ESAP):[26] The ESAP is mandated by PU Code 2790, which requires gas and electric corporations to perform home weatherization services for low-income households, and defines those services to include the installation of HVAC measures, lighting measures, water heating conservation measures, and infiltration measures which include caulking and weather stripping. Weatherization services may also include other building conservation measures, energy-efficient appliances and energy education programs. ESAP is considered a low-income program for policymaking purposes, because the program's purpose is to improve the welfare of California's low-income population, by subsidizing and managing energy efficiency improvements for low income residences. The program accounts for 0.6% of the IOUs' total revenue requirement.

[25] PG&E implemented a Tier 3 CARE rate on November 1, 2011 in accordance with SB 695 (October 2009) and D.11-05-047.
[26] Formerly known as the Low Income Energy Efficiency (LIEE) Program.

V. Bonds and Regulatory Fees

The $1.3 billion revenue requirement for bonds constitutes the ongoing costs to ratepayers for the 2000-01 energy crisis. During the era of electric restructuring, the State and the utilities issued a series of bonds to amortize the costs of energy restructuring and the energy crisis. Since the energy crisis, these bond costs have decreased from a peak of $2 billion in 2004 to $1.3 billion in 2011.

Figure 5.1: Trends in Bond Expenses



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 their June 1996 levels, and reduced rates for residential and small commercial customers by 10%.

DWR Bonds were issued in 2003 to recover the costs incurred by the State of California to purchase power during the energy crisis. A $7.2 billion balance remains outstanding on the DWR bonds and 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 $2.7 billion as a Regulatory Asset. The Energy Recovery Bonds were issued by PG&E in 2003 to reduce the financing cost of the Regulatory Asset to ratepayers. But for the bonds, the Regulatory Asset would be financed at PG&E's weighted cost of capital which was higher than the cost of these bonds. The Energy Recovery Bonds are scheduled to be repaid by the end of 2012.

Table 5.2: 2011 Bond Expenses (000)

	PG&E	SCE	SDG&E	Total
DWR Bond Charges	$388,993	$391,495	$94,770	$875,258
Rate Reduction Bonds	$0	$0	$0	$0
Energy Recovery Bonds	$437,225	n/a	n/a	$437,225
Total	**$826,218**	**$391,495**	**$94,770**	**$1,312,483**

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. An example is the Risk/Reward Incentive Mechanism for promoting energy efficiency and the Performance Based Ratemaking incentives. In total, this entire category of expenses accounted for less than 1% of the 2011 revenue requirement.

Table 5.3: 2011 Regulatory Fees (000)

	PG&E	SCE	SDG&E	Total
Fees				
CPUC fee*	$20,602	$20,427	$0	$41,029
Catastrophic Events Memorandum Acct.	$0	$0	$6,184	$6,184
Franchise Fees & Uncollectible Surcharge	$0	$15,791	$4,345	$20,136
Environmental Enhancement	$10,103	$0	$0	$10,103
RD&D	$35,218	$28,563	$6,210	$69,991
Nuclear Decommissioning	$41,705	$23,573	$8,070	$73,348
Spent Nuclear Fuel	$0	$6,119	$948	$7,067
DOE D&D Fees	$0	$0	$0	$0
Nuclear Decommissioning FF&U	$0	$344	$95	$439
Incentives				
AEAP Incentive	$0	$24,092	$0	$24,092
Non-Utility Affiliate Credit/RCRA Offset	$0	($11,132)	$0	($11,132)
Performance-Based Regulations	$0	$0	$0	$0
Customer Service and Safety Performance	$23,571	$0	$0	$23,571
Total	**$131,199**	**$107,777**	**$25,852**	**$264,826**

* 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.

Definition of Fees

- **CPUC Fee:** This is the annual fee to recover the CPUC's operating costs.
- **Catastrophic Events Memorandum Account**: 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.

- **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.
- **Uncollectibles:** Includes accounts receivable that have defaulted or cannot be collected.
- **Environmental Enhancement:** A (PG&E only) program established by the PG&E bankruptcy settlement to provide environmental enhancement of a dedicated watershed, which was donated to a public trust as part of the settlement.
- **RD&D:** A public purpose program funded consistent with PU Code Section 399.8. Distribution of funds is currently overseen by the California Energy Commission.
- **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.
- **Hazardous Substance Mechanism (HSM)**: An account that provides a mechanism for allocating historical hazardous waste costs (such as from old-time coal to gas plants) among shareholders and ratepayers, including the allocation of insurance recoveries, if any.

<u>Incentives</u>

- **Annual Earnings Assessment Proceeding (AEAP) Incentive:** Incentives received by a utility, based on a portion of the net present value of the savings achieved by ratepayers participating in energy efficiency programs.
- **Performance-Based Regulation Incentive:** The mechanism enables the investor owned utilities to earn rewards on energy efficiency programs in amounts comparable to what the companies would otherwise earn through supply side investments. The decisions establish a performance standard for the utilities, under which the utilities earn incentives if their energy efficiency program portfolios achieve certain quantitative energy efficiency savings goals.
- **Non-Utility Affiliate Credit/ Reduced Capital Recovery Amount Offset:** Mechanism that initially provided for additional annual nuclear depreciation expense of $75 million, which was offset by suspending annual distribution depreciation expense of $75 million, in accordance with D.94-05-068. Requirement was modified by D.99-10-057, and D.02-04-016.

VI. Natural Gas Utility Ratepayer Costs

The CPUC determines the reasonableness of operational costs and public purpose programs, cost allocation among customer classes and rate design for Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SoCalGas) and San Diego Gas and Electric Company (SDG&E). 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, which are recovered in the transportation component of customer rates, and 3) costs associated with gas public purpose programs (PPP). Unlike for electricity procurement, the CPUC does not set an annual authorized revenue requirement for gas procurement costs. The core gas procurement costs in this report reflect the utilities' actual natural gas commodity costs from 2011. Core gas procurement costs are recovered in utility gas procurement rates which are adjusted monthly. Costs reported for transportation and PPPs reflect amounts authorized by the CPUC.

For 2011, total natural gas utility costs significantly decreased from 2010, and were at their lowest level in the last five years, due primarily to a significant decrease in the price of natural gas since mid-2008. As the tables below show, costs for transportation show moderately steady increases year to year since 2007. However, costs for public purpose programs have markedly increased during that time, particularly on a percentage basis.

Table 6.1: 2011 Gas Revenue Requirement Summary by Key Components (000)

	PG&E	SoCalGas	SDG&E	Total
Core Procurement	$1,520,282	$1,538,869	$206,615	$3,265,766
Transportation	$1,533,332	$1,971,438	$276,573	$3,781,343
Public Purpose Programs	$262,869	$287,564	$45,583	$596,016
Totals	$3,316,483	$3,797,871	$528,771	$7,643,125

Figure 6.2: Trends in Gas Utility Revenue Requirements

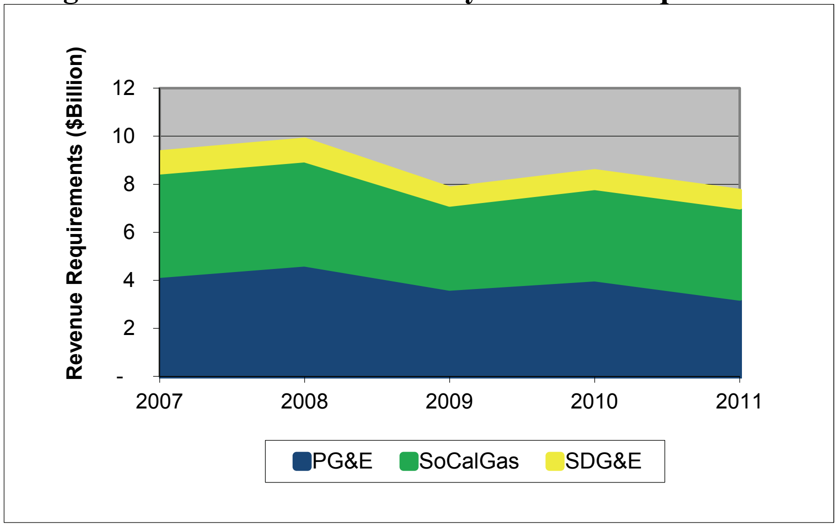


Figure 6.3: Trends in Gas Utility Revenue Requirement Components

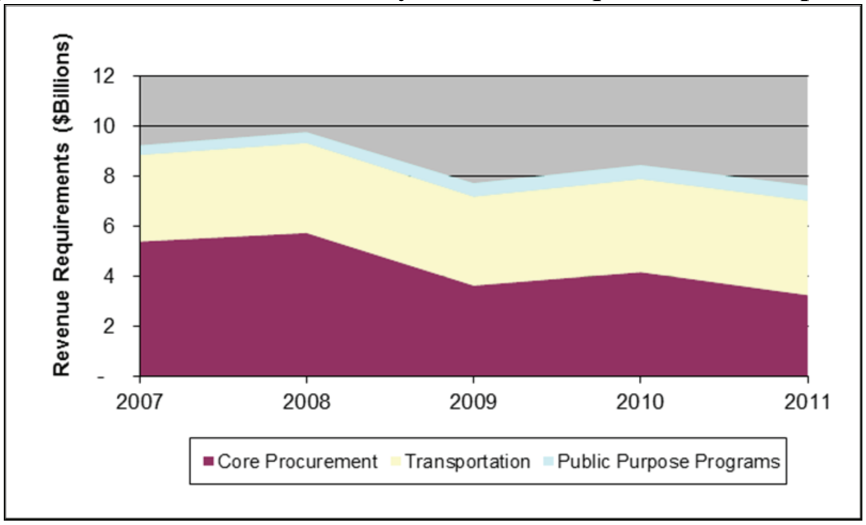


Table 6.4: Historic Gas Utility Revenue Requirement Summary (000)

	2007	2008	2009	2010	2011
Core Procurement	$5,410,391	$5,753,175	$3,647,509	$4,186,881	$3,265,766
Transportation	$3,464,554	$3,595,241	$3,559,641	$3,722,046	$3,781,343
Public Purpose Programs	$375,358	$429,897	$531,482	$553,460	$596,016
Total	**$9,250,303**	**$9,778,313**	**$7,738,632**	**$8,462,387**	**$7,643,125**

Table 6.5: Percent Change in Gas Utility Revenue Requirements from 2007 to 2011

	Core Procurement	Transportation	Public Purpose Programs
PG&E	-44%	7%	98%
SoCalGas	-34%	12%	34%
SDG&E	-45%	-1%	66%

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 2011 decreased by 22% from 2010. Overall, natural gas core procurement costs have decreased by 40% since 2007. In 2011, the core gas procurement costs comprised about 43% of the total utility gas costs.

Although core gas customers – primarily residential and small commercial customers – have the option to choose a non-utility natural gas supplier, natural gas utilities in California provide procurement service for over 95% of core customers. Almost all larger, “noncore” natural gas consumers – industrial customers or electric generators – procure their own natural gas supplies from non-utility suppliers.

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, 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, the state's natural gas utilities' procurement costs have fallen drastically since mid-2008. Neither the Commission nor the FERC regulates the price of natural gas. The decrease in the price of natural gas has resulted from developments in the natural gas commodity market. As the following table shows, natural gas utility procurement costs in 2011 were at their lowest level in the last five years due primarily to the considerable rise in domestic natural gas production in recent years. This increase in production has created a surplus in domestic supply resulting in the lowest total core gas procurement rates in at least the last five years.

Figure 6.6: Revenue Requirements for Utility Natural Gas Core Procurement

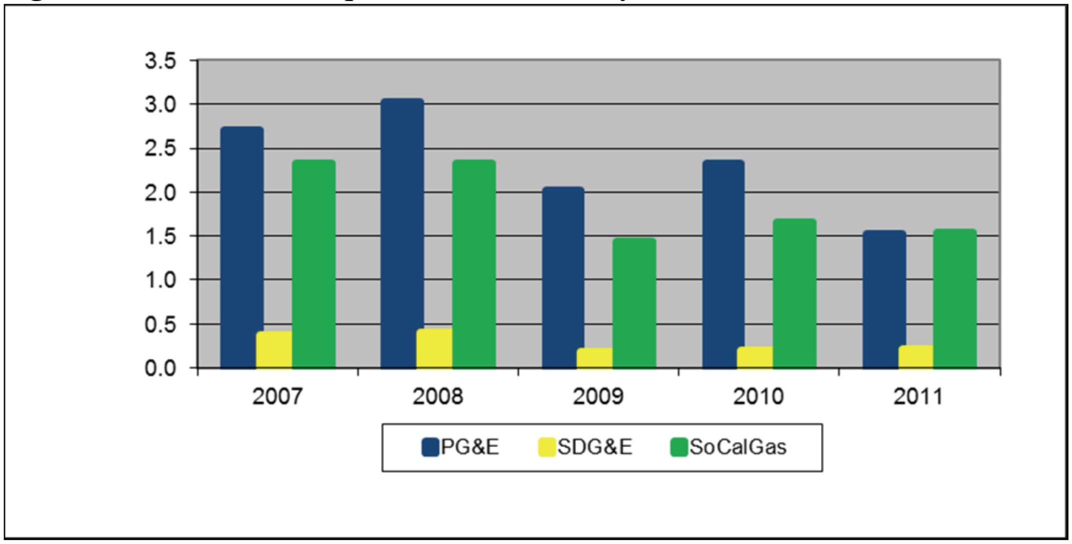


Table 6.7: Historic Revenue Requirements for Core Procurement Summary (000)

	2007	2008	2009	2010	2011
PG&E	$2,705,231	$3,022,339	$2,020,976	$2,327,868	$1,520,282
SoCalGas	$2,331,536	$2,330,774	$1,441,099	$1,656,802	$1,538,869
SDG&E	$373,624	$400,062	$185,434	$202,211	$ 206,615
TOTAL	**$5,410,391**	**$5,753,175**	**$ 3,647,509**	**$4,186,881**	**$3,265,766**

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 moderately increased in recent years. In 2011, the gas operational costs were about 49% of the total utility gas costs. The bulk of these revenue requirements are primarily determined by the CPUC in three types of major proceedings: general rate cases for PG&E, SoCalGas and SDG&E, PG&E transmission and storage proceedings, and SoCalGas/SDG&E cost allocation proceedings.

The following table shows that total authorized revenue requirements for transmission, distribution, storage, and customer services, combined under the "transportation" category, have been fairly steady in recent years, with an increase of 9% between 2007 through 2011. Over the last year, PG&E and SDG&E experienced slight decreases in transportation costs while SoCalGas had a slight increase. In total, the transportation costs increased by 2% from last year.

These costs are mainly recovered by the utilities through end-use transportation rates, backbone transmission rates (for PG&E) or "firm access rights" rates (for SoCalGas), and storage rates. Such rates are generally changed annually, in accordance with previous CPUC decisions which have adopted revenue requirements, cost allocation and rate design.

PG&E backbone transmission service, SoCalGas firm access rights service and both utilities' storage service are optional services for noncore customers. If a noncore customer opts not to take those services, they would not be charged for those services. Such customers typically take delivery of supplies at the utility "citygate" from a marketer (who may be paying for these services), and only pay the utility transportation rate.

Figure 6.8: Revenue Requirements for Utility Natural Gas Transmission, Distribution and Storage

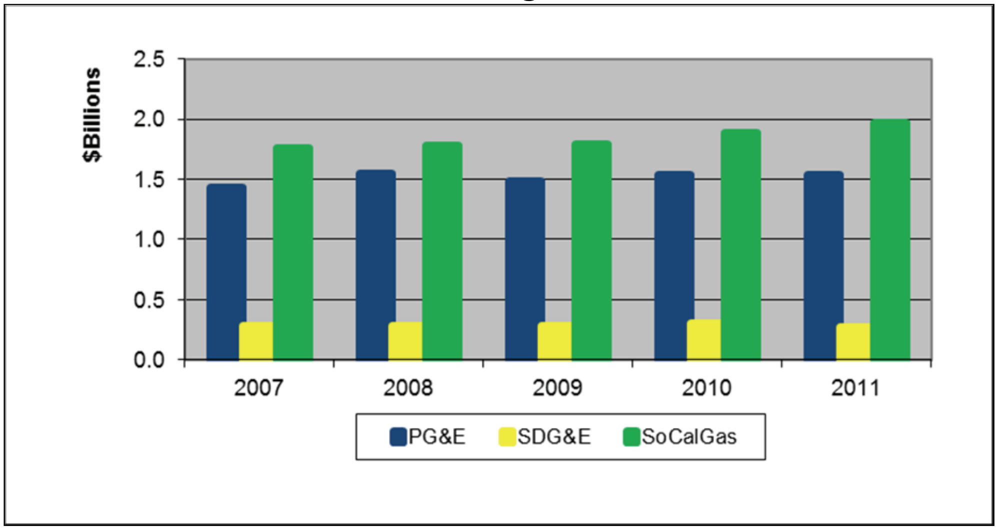


Table 6.9: Historic Revenue Requirements for Transportation Summary (000)

	2007	2008	2009	2010	2011
PG&E	$1,427,208	$1,543,010	$1,488,501	$1,541,446	$1,533,332
SoCalGas	$1,758,678	$1,774,960	$1,785,220	$1,880,826	$1,971,438
SDG&E	$278,668	$277,271	$285,920	$299,774	$276,573
TOTAL	**$3,464,554**	**$3,595,241**	**$3,559,641**	**$3,722,046**	**$3,781,343**

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 Rates for Energy (CARE) subsidy, and the gas public interest research and development program administered by the California Energy Commission. The CARE subsidy comprised 41% of total PPP program costs in 2011.[27] Gas PPP costs are determined in various CPUC proceedings associated with the particular type of gas PPP. Gas PPP costs have increased significantly in recent years, but are a small part of total costs.

Costs authorized by the CPUC for natural gas PPPs have increased by 59% overall since 2007. Gas PPP costs have increased due to significant increases for energy efficiency and low-income energy efficiency programs and the CARE subsidy. With these increases, gas PPP costs comprised about 8% of total utility costs in 2011, up from 6% in 2010.

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 6.10: Revenue Requirements for Utility Public Purpose Programs

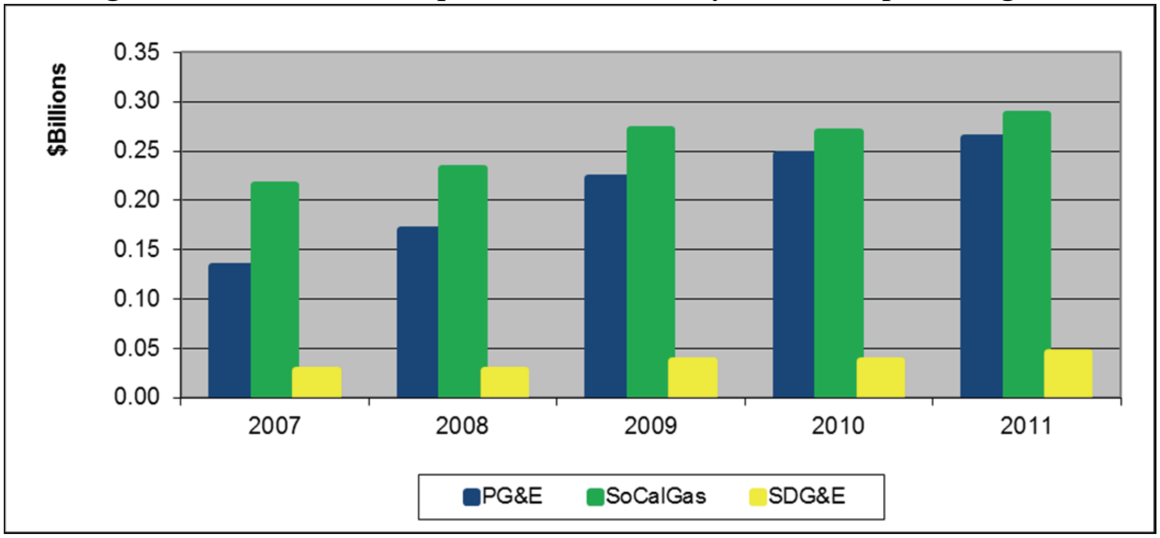


Table 6.11: Historic Revenue Requirements for Public Purpose Programs Summary (000)

	2007	2008	2009	2010	2011
PG&E	$132,805	$169,869	$222,589	$246,480	$262,869
SoCalGas	$215,155	$232,437	$271,411	$269,412	$287,564
SDG&E	$27,398	$27,591	$37,482	$37,568	$45,583
TOTAL	**$375,358**	**$429,897**	**$531,482**	**$553,460**	**$596,016**

[27] See page 39 for a breakdown of PPP costs.

Appendix A: AB 67 Table— 2011 Electric Revenue Requirement

	Federal/State Mandate	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total	-	-	**5,289,796**	**4,128,137**	**938,595**
Qualifying Facilities	Federal PURPA, 1978; PUC Section 454.5(d)(3)	CPUC Decisions	299,063	1,416,515	55,831
General Rate Case Revenues		CPUC Decisions	1,875,913	1,337,741	237,738
Renewable Portfolio Standard	PUC Section 454.5(d)(3)	CPUC Decisions	901,100	w/QFs	121,063
Other Utility Fuel & Purchased Power	PUC Section 454.5(d)(3)	CPUC Decisions	2,212,480	1,366,806	523,963
Other		CPUC Decisions, Resolutions	1,240	7,075	0
Transmission Total			**1,201,083**	**586,091**	**430,250**
Reliability Services	FERC Order 459		31,622	4,367	19,936
Transmission Access Charge	FERC		204,302	(32,197)	5,979
Transmission Owner Rate Case Revenues	FERC		985,328	467,951	406,900
Other - FERC Rate Case Revenues	FERC		(20,169)	145,970	(2,565)
Distribution Total			**4,022,279**	**4,101,430**	**1,300,699**
AMI/Smart Meter		Report	178,386	203,474	70,572
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	29,823	28,000	10,035
California Solar Initiative		CPUC Decisions	106,077	110,000	25,000
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	(8,899)	71,162	14,527
Catastrophic Events	PUC Section 454.9(a)	CPUC Decisions	0	16,491	6,184
General Rate Case Revenues		CPUC Decisions	3,626,834	3,636,425	1,161,001
Hazardous Substance Mechanism		CPUC Decisions	11,638	2,491	279
AEAP Incentives		CPUC Decisions	0	24,092	0
Low Emission Vehicle Program	PUC Section 740.3 & 740.8	CPUC Decisions, Resolutions	0	0	0
CPUC Fee	PUC Section 431	CPUC Resolution M-4816	20,602	20,427	0
Other		CPUC Decisions, Resolutions	33,709	(11,132)	4,396
PBR Sharing Mechanism		CPUC Decisions, Resolutions	0	0	7,579
Customer Service & Safety Awards/Penalties		CPUC Decisions, Resolutions	24,109	0	1,126
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**58,678**	**7,667**	**8,336**
Public Purpose Programs Total			**678,335**	**687,481**	**128,033**
Energy Efficiency, PUCode 399.8	PUC Section 399.8	CPUC Decisions, E-3792	120,588	125,013	13,640
RD&D PUCode 399.8	PUC Section 399.8	CPUC Resolution E-3792	35,218	28,563	5,902
Renewables, PUCode 399.8	PUC Section 399.8	CPUC Resolution E-3792	36,826	29,924	7,810
Energy Efficiency, non-PUCode 399.8		CPUC Decisions	235,061	379,868	33,860
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	93,454	63,414	10,788
CARE Adm., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	157,188	60,699	56,033
DWR Power Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**(226,827)**	**610,465**	**169,000**
-					
DWR Bond Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**388,993**	**391,495**	**94,770**
AB1890 Rate Reduction Bonds	AB 1890, PUC Section 368(a), 840-847	CPUC Decisions, Resolutions	**0**	**0**	**0**
Ongoing Competition Transition Charge	AB 57, PUC Section 367(a) & 369	CPUC Decisions	**627,176**	**590,718**	**62,615**
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	**404,531**	**0**	**0**
Franchise Fee Surcharge	PUC Sections 6350-6354, 6231	CPUC Decisions	0	**17,893**	**17,505**
-					
Electric Total			**12,444,044**	**11,121,377**	**3,149,803**

† This table shows revenue requirements collected in rates, after balancing account adjustments.

Appendix A: AB 67 Table— 2010 Electric Revenue Requirement

	Federal/State Mandate	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total	-	-	**5,476,294**	**4,161,344**	**1,039,566**
Qualifying Facilities	Federal PURPA, 1978; PUC Section 454.5(d)(3)	CPUC Decisions	484,803	1,699,822	94,441
General Rate Case Revenues		CPUC Decisions	1,589,228	1,352,969	211,063
Renewable Portfolio Standard	PUC Section 454.5(d)(3)	CPUC Decisions	465,610	w/QFs	161,765
Other Utility Fuel & Purchased Power	PUC Section 454.5(d)(3)	CPUC Decisions	2,925,832	1,098,856	572,297
Other		CPUC Decisions, Resolutions	10,823	9,697	0
Transmission Total			**840,141**	**578,338**	**273,077**
Reliability Services	FERC Order 459		52,901	(3,840)	12,193
Transmission Access Charge	FERC		84,784	(45,849)	(1,289)
Transmission Owner Rate Case Revenues	FERC		844,167	581,827	268,049
Other - FERC Rate Case Revenues	FERC		(141,711)	46,200	(5,876)
Distribution Total			**3,744,531**	**3,916,356**	**1,157,038**
AMI/Smart Meter		Report	140,071	93,599	64,757
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	30,186	28,000	10,035
California Solar Initiative		CPUC Decisions	0	110,000	25,000
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	85,243	71,162	16,585
Catastrophic Events	PUC Section 454.9(a)	CPUC Decisions	5,922	0	0
General Rate Case Revenues		CPUC Decisions	3,408,056	3,571,814	982,858
Hazardous Substance Mechanism		CPUC Decisions	8,987	7,237	349
AEAP Incentives		CPUC Decisions	0	25,652	0
Low Emission Vehicle Program	PUC Section 740.3 & 740.8	CPUC Decisions, Resolutions	0	0	(81)
CPUC Fee	PUC Section 431	CPUC Resolution M-4816	20,645	20,024	0
Other		CPUC Decisions, Resolutions	14,007	(11,132)	57,199
PBR Sharing Mechanism		CPUC Decisions, Resolutions	0	0	0
Customer Service & Safety Awards/Penalties		CPUC Decisions, Resolutions	31,414	0	336
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**26,034**	**53,203**	**10,408**
Public Purpose Programs Total			**592,001**	**571,167**	**135,092**
Energy Efficiency, PUCode 399.8	PUC Section 399.8	CPUC Decisions, E-3792	115,593	82,785	35,640
RD&D PUCode 399.8	PUC Section 399.8	CPUC Resolution E-3792	35,218	28,244	5,887
Renewables, PUCode 399.8	PUC Section 399.8	CPUC Resolution E-3792	36,826	29,590	4,493
Energy Efficiency, non-PUCode 399.8		CPUC Decisions	254,801	306,834	43,127
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	90,044	61,561	11,272
CARE Adm., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	59,519	62,153	34,673
DWR Power Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**1,004,164**	**836,752**	**331,000**
-					
DWR Bond Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**411,133**	**391,013**	**96,861**
AB1890 Rate Reduction Bonds	AB 1890, PUC Section 368(a), 840-847	CPUC Decisions, Resolutions	**0**	**0**	**0**
Ongoing Competition Transition Charge	AB 57, PUC Section 367(a) & 369	CPUC Decisions	**310,635**	**467,539**	**46,361**
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	**193,775**	**0**	**0**
-					
Franchise Fee Surcharge	PUC Sections 6350-6354, 6231	CPUC Decisions	**0**	**15,070**	**6,755**
-					
Electric Total			**12,598,708**	**10,990,782**	**3,096,158**

†This table shows revenue requirements collected in rates, after balancing account adjustments.

Appendix A: AB 67 Table— 2009 Electric Revenue Requirement

	Federal/State Mandate	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total	-	-	**5,521,821**	**5,216,362**	**1,062,553**
Qualifying Facilities	Federal PURPA, 1978; PUC Section 454.5(d)(3)	CPUC Decisions	1,387,873	2,140,916	109,432
General Rate Case Revenues		CPUC Decisions	1,219,636	1,172,663	187,998
Renewable Portfolio Standard	PUC Section 454.5(d)(3)	CPUC Decisions	510,078	w/QFs	106,172
Other Utility Fuel & Purchased Power	PUC Section 454.5(d)(3)	CPUC Decisions	2,388,938	1,887,181	658,951
Other		CPUC Decisions, Resolutions	15,296	15,602	0
Transmission Total			**771,022**	**388,902**	**259,053**
Reliability Services	FERC Order 459		35,584	(14,595)	10,219
Transmission Access Charge	FERC		(5,265)	77,326	(29,989)
Transmission Owner Rate Case Revenues	FERC		830,751	447,433	293,027
Other - FERC Rate Case Revenues	FERC		(90,048)	(121,262)	(14,204)
Distribution Total			**3,659,068**	**3,830,973**	**1,044,381**
AMI/Smart Meter		Report	90,954	97,332	40,315
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	30,186	28,000	10,035
California Solar Initiative		CPUC Decisions	141,436	0	0
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	95,266	47,803	15,390
Catastrophic Events	PUC Section 454.9(a)	CPUC Decisions	12,586	7,691	0
General Rate Case Revenues		CPUC Decisions	3,207,111	3,732,404	968,274
Hazardous Substance Mechanism		CPUC Decisions	6,451	7,282	242
AEAP Incentives		CPUC Decisions	0	24,700	0
Low Emission Vehicle Program	PUC Section 740.3 & 740.8	CPUC Decisions, Resolutions	0	0	315
CPUC Fee	PUC Section 431	CPUC Resolution M-4816	21,147	0	0
Climate Smart			4,293	0	0
Other		CPUC Decisions, Resolutions	14,653	(11,132)	0
PBR Sharing Mechanism		CPUC Decisions, Resolutions	0	(103,106)	0
Customer Service & Safety Awards/Penalties		CPUC Decisions, Resolutions	34,986	0	9,810
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**23,846**	**51,348**	**10,298**
Public Purpose Programs Total			**157,190**	**207,858**	**28,247**
Energy Efficiency, PUCode 399.8	PUC Section 399.8	CPUC Decisions, E-3792	(149,976)	99,076	(4,800)
RD&D PUCode 399.8	PUC Section 399.8	CPUC Resolution E-3792	34,436	28,244	6,805
Renewables, PUCode 399.8	PUC Section 399.8	CPUC Resolution E-3792	36,009	(161,670)	(39,766)
Energy Efficiency, non-PUCode 399.8		CPUC Decisions	203,706	155,586	51,338
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	68,308	60,242	12,527
CARE Adm., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	(35,293)	26,379	2,143
DWR Power Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**1,593,664**	**1,379,923**	**542,715**
-					
DWR Bond Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**406,569**	**426,780**	**88,238**
AB1890 Rate Reduction Bonds	AB 1890, PUC Section 368(a), 840-847	CPUC Decisions, Resolutions	**(14,194)**	**0**	**0**
Ongoing Competition Transition Charge	AB 57, PUC Section 367(a) & 369	CPUC Decisions	**426,566**	**106,365**	**43,895**
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	**202,777**	**0**	**0**
-					
Franchise Fee Surcharge	PUC Sections 6350-6354, 6231	CPUC Decisions	**0**	**8,290**	**4,597**
-					
Electric Total			**12,748,329**	**11,616,801**	**3,083,977**

†This table shows revenue requirements collected in rates, after balancing account adjustments.

Appendix A: AB 67 Table— 2011 Gas Revenue Requirement

	Federal/State Mandate	CPUC Mandate	PG&E	SDG&E	SoCalGas
Core Procurement Total			**1,520,282**	**206,615**	**1,538,869**
Core Gas Supply Portfolio		CPUC Decisions	1,100,364	206,615	1,527,637
Other		CPUC Decisions	325,406	0	0
10/20 Winter Gas Savings		CPUC Resolutions	(8,784)	0	0
Core Gas Hedging		Report	103,296	0	5,010
Incentive Mechanism		Report	0	0	6,222
Transportation Total			**1,533,332**	**276,573**	**1,971,438**
Distribution		CPUC Decisions	1,022,937	257,949	1,909,388
Transmission		CPUC Decisions	353,471	0	0
Advanced Metering Infrastructure		Report	100,488	16,999	0
Smart Meter			0	0	0
Self Gen Inc Prog (SGIP)	PUC Section 379.6 (a)	CPUC Decisions	6,480	755	8,135
Climate Smart			0	0	0
Calif Solar Initiative (CSI)		CPUC Decisions	0	773	0
Annual Earning Assessment (AEAP)		CPUC Decisions	5,568	0	9,931
Low Emission Vehicle (LEV)	PUC Section 740.3 & 740.8	CPUC Decisions	0	0	45,091
Haz Substance Mechanism (HSM)		CPUC Decisions	26,880	616	5,998
Performance Based Regulation (PBR)		CPUC Decisions, Resolutions	0	0	0
Customer Service & Safety Performance Indicator		CPUC Decisions, Resolutions	0	299	2,250
Non Public Interest Research, Dvlp & Demo (RD&D)		CPUC Decisions	0	0	(2,040)
Core Pricing Flexibility Program		CPUC Decisions	0	0	324
Non core competitive load growth program		CPUC Decisions	0	0	707
Catastrophic Event Memo Acct (CEMA)	PUC Section 454.9 (a), Res E-3238	CPUC Decisions, Resolutions	0	157	0
Z-Factor		CPUC Decisions	0	0	0
Other Balancing Accts Balances		Report	71	(3,200)	(35,047)
CPUC Fee	PUC Section 431	Resolution M-4816	3,210	0	0
Franchise Fees & Uncollectibles	PUC Section 6231	CPUC Decisions	2,000	0	0
Franchise Fee Surcharge (G-SUR)	PUC Sections 6350-6354	CPUC Resolutions	12,227	2,225	26,701
Public Purpose Program Surcharges Total			**262,869**	**45,583**	**287,564**
Energy Efficiency (EE) Programs	PUC Sections 399.8, 890-900	CPUC Decisions	89,926	20,677	66,027
Low Income Energy Efficiency (LIEE)	PUC Sections 739.1, 890-900, 2790	CPUC Decisions	64,022	9,540	78,256
Public Interest RD&D and State Board of Equalization (BOE)	PUC Sections 740, 890-900	CPUC Decisions	10,557	1,285	12,640
Calif Alternate Rates for Energy (CARE) Program	PUC Sections 739.1 & .2, 890-900	CPUC Decisions	98,364	14,081	130,641
GAS TOTAL			**3,316,483**	**528,771**	**3,797,871**