PG&E Corp
Form 10-K
February 11, 2014

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended December 31, 2013

Or

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _________ to ___________

Commission File Number	Exact Name of Registrant as specified in its charter	State or Other Jurisdiction of Incorporation or Organization	IRS Employer Identification Number
1-12609	PG&E CORPORATION	California	94-3234914
1-2348	PACIFIC GAS AND ELECTRIC COMPANY	California	94-0742640

77 Beale Street, P.O. Box 770000	77 Beale Street, P.O. Box 770000
San Francisco, California 94177	San Francisco, California 94177
(Address of principal executive offices) (Zip Code)	(Address of principal executive offices) (Zip Code)
(415) 973-1000	(415) 973-7000
(Registrant's telephone number, including area code)	(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
PG&E Corporation: Common Stock, no par value	New York Stock Exchange
Pacific Gas and Electric Company: First Preferred Stock, cumulative, par value $25 per share: Redeemable: 5% Series A, 5%, 4.80%, 4.50%, 4.36% Nonredeemable: 6%, 5.50%, 5%	NYSE Amex Equities

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act:

PG&E Corporation	Yes þ No
Pacific Gas and Electric Company	Yes þ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act:

PG&E Corporation	Yes No þ
Pacific Gas and Electric Company	Yes No þ

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

PG&E Corporation	Yes þ No
Pacific Gas and Electric Company	Yes þ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

PG&E Corporation	Yes þ	No o
Pacific Gas and Electric Company	Yes þ	No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K:

PG&E Corporation	þ
Pacific Gas and Electric Company	þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company (as defined in Rule 12b-2 of the Exchange Act). (Check one):

PG&E Corporation	Pacific Gas and Electric Company
Large accelerated filer þ	Large accelerated filer
Accelerated filer	Accelerated filer
Non-accelerated filer	Non-accelerated filer þ
Smaller reporting company	Smaller reporting company

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

PG&E Corporation	Yes	No þ
Pacific Gas and Electric Company	Yes	No þ

Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants as of June 30, 2013, the last business day of the most recently completed second fiscal quarter:

PG&E Corporation common stock	$20,326 million
Pacific Gas and Electric Company common stock	Wholly owned by PG&E Corporation

Common Stock outstanding as of February 3, 2014:

PG&E Corporation:	457,663,407
Pacific Gas and Electric Company:	264,374,809 shares (wholly owned by PG&E Corporation)

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the documents listed below have been incorporated by reference into the indicated parts of this report, as specified in the responses to the item numbers involved:

Designated portions of the combined 2013 Annual Report to Shareholders	Part I (Items 1, 1A and 3), Part II (Items 5, 6, 7, 7A, 8 and 9A)
Designated portions of the Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders	Part III (Items 10, 11, 12, 13 and 14)

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UNITS OF MEASUREMENT

1 Kilowatt (kW)	=	One thousand watts
1 Kilowatt-Hour (kWh)	=	One kilowatt continuously for one hour
1 Megawatt (MW)	=	One thousand kilowatts
1 Megawatt-Hour (MWh)	=	One megawatt continuously for one hour
1 Gigawatt (GW)	=	One million kilowatts
1 Gigawatt-Hour (GWh)	=	One gigawatt continuously for one hour
1 Kilovolt (kV)	=	One thousand volts
1 MVA	=	One megavolt ampere
1 Mcf	=	One thousand cubic feet
1 MMcf	=	One million cubic feet
1 Bcf	=	One billion cubic feet
1 MDth	=	One thousand decatherms

GLOSSARY

The following terms and abbreviations appearing in the text of this report have the meanings indicated below.

2013 Annual Report	PG&E Corporation's and Pacific Gas and Electric Company's combined Annual Report on Form 10-K for the year ended December 31, 2013, including the information incorporated by reference into the report
AB 32	California Global Warming Solutions Act of 2006
CAISO	California Independent System Operator
CARB	California Air Resources Board
CCA	Community choice aggregator
CEC	California Energy Commission
Central Coast Board	Central Coast Regional Water Quality Control Board
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CO2	carbon dioxide
CO2-e	CO2-equivalent
CPUC	California Public Utilities Commission
CSI	California Solar Initiative
DOE	U.S. Department of Energy
EPA	Environmental Protection Agency
ERRA	Energy Resource Recovery Account
ESC	Engineers and Scientists of California
Exchange Act	Securities Exchange Act of 1934, as amended
FERC	Federal Energy Regulatory Commission
GHG	greenhouse gas
GRC	general rate case
GTN	Gas Transmission Northwest Corporation
GT&S	gas transmission and storage
IBEW	International Brotherhood of Electrical Workers
LTIP	PG&E Corporation long-term incentive plan
MD&A	Management’s Discussion and Analysis of Financial Condition and Results of Operations
MGP	manufactured gas plant
NERC	North American Electric Reliability Corporation
NOx	nitrogen oxide
NRC	Nuclear Regulatory Commission
NTSB	National Transportation Safety Board
ORA	Office of Ratepayer Advocates
OSC	CPUC Order to Show Cause
PHMSA	Pipeline and Hazardous Materials Safety Administration
PSEP	pipeline safety enhancement plan
PV	photovoltaic
QF(s)	qualified facilities
ROE	return on equity
RPS	renewable portfolio standard
SEC	U.S. Securities and Exchange Commission
SED	Safety and Enforcement Division of the CPUC, formerly known as the Consumer Protection and Safety Division or the CPSD

SEIU	Service Employees International Union, United Service Workers West
SO2	sulfur dioxide
TO	transmission owner
TURN	The Utility Reform Network
Utility	Pacific Gas and Electric Company
WECC	Western Interconnection to the Western Electricity Coordinating Council

PART I

ITEM 1. Business

General

PG&E Corporation, incorporated in California in 1995, is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility operating in northern and central California. The Utility was incorporated in California in 1905. PG&E Corporation became the holding company of the Utility and its subsidiaries on January 1, 1997. The Utility's revenues are generated mainly through the sale and delivery of electricity and natural gas to customers.

The principal executive offices of PG&E Corporation and the Utility are located at 77 Beale Street, P.O. Box 770000, San Francisco, California 94177. PG&E Corporation's telephone number is (415) 973-1000 and the Utility's telephone number is (415) 973-7000. PG&E Corporation and the Utility file or furnish various reports with the SEC. These reports, including Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and any amendments to those reports filed or furnished pursuant to Sections 13(a) or 15(d) of the Exchange Act, are available free of charge on both PG&E Corporation's website, www.pgecorp.com, and the Utility's website, www.pge.com, as promptly as practicable after they are filed with, or furnished to, the SEC. The information contained on these websites is not incorporated by reference into this Annual Report on Form 10-K and should not be considered part of this report.

This is a combined Annual Report on Form 10-K of PG&E Corporation and the Utility and includes information incorporated by reference from the joint Annual Report to Shareholders for the year ended December 31, 2013, which is attached to this report as Exhibit 13 and the Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders. The 2013 Annual Report contains forward-looking statements that are necessarily subject to various risks and uncertainties. For a discussion of the significant risks that could affect the outcome of these forward-looking statements and PG&E Corporation's and the Utility's future financial condition and results of operations, see the information in the 2013 Annual Report under the headings "Cautionary Language Regarding Forward-Looking Statements" and "Risk Factors" which appear under the heading "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Natural Gas Operations

During 2013, the Utility continued to make significant progress on efforts to improve the safety and reliability of its natural gas operations, including performing extensive pipeline testing and monitoring, and replacing and upgrading equipment. Much of this work is part of the Utility's PSEP, approved by the CPUC in December 2012, to modernize and upgrade its natural gas transmission system to meet new, industry-wide safety standards. In July 2013, the Utility completed its search and review of records relating to pipeline pressure validation for all approximately 6,750 miles of its natural gas transmission system. Many of these improvement efforts satisfy recommendations made to the Utility by the NTSB and the CPUC in 2010 and 2011 following their investigations into the rupture of one of the Utility's natural gas transmission pipelines in San Bruno, California on September 9, 2010 (the "San Bruno accident"). (For more information, see "Natural Gas Utility Operations" below.)

During 2013, the Utility settled the majority of the civil lawsuits that were filed after the San Bruno accident. The CPUC investigations and the criminal investigation that were commenced after the San Bruno accident are still unresolved. The CPUC's SED also may take enforcement action with respect to numerous reports the Utility has filed to report noncompliance with various natural gas regulations. See information under the headings within MD&A entitled "Natural Gas Matters" and Note 14: Commitments and Contingencies of the Notes to the Consolidated Financial

Statements in the 2013 Annual Report which information is incorporated herein by reference.

Electricity Operations

During 2013, the Utility made significant capital investments to improve and modernize its electricity operations by repairing, replacing, or upgrading equipment to improve safety and reliability. The Utility has substantially completed the installation of advanced electric and gas meters throughout its service territory and continued taking steps to lay the foundation for the development of a "smart grid" to enable customers to have better control over their energy usage and costs, to integrate new sources of energy, and to enable the continued safe and reliable operation of the grid. In 2013, the Utility received regulatory approval to pilot and test new "smart grid" technologies that have the potential to support the provision of safe, reliable and affordable electric service. (For more information, see "Electric Utility Operations" below.)

Employees

At December 31, 2013, PG&E Corporation and its subsidiaries had 21,166 regular employees, including 21,159 regular employees of the Utility. Of the Utility's regular employees, 13,150 are covered by collective bargaining agreements with three labor unions: the IBEW; the ESC; and the SEIU. There are two collective bargaining agreements with IBEW. Both bargaining agreements expire on December 31, 2014. The ESC collective bargaining agreement also expires on December 31, 2014. The SEIU collective bargaining agreement expires on July 31, 2015.

Regulatory Environment

The Utility's business is subject to a complex set of energy, environmental and other laws, regulations, and regulatory proceedings at the federal, state, and local levels. This section and the "Ratemaking Mechanisms" section below summarize some of the more significant laws, regulations, and regulatory proceedings affecting the Utility. For discussion of specific pending regulatory matters that are expected to affect the Utility, see the information under the headings within MD&A entitled "Regulatory Matters" and "Natural Gas Matters" in the 2013 Annual Report, which information is incorporated herein by reference.

PG&E Corporation is a "public utility holding company" as defined under the Public Utility Holding Company Act of 2005 and is subject to regulatory oversight of the FERC. PG&E Corporation and its subsidiaries are exempt from all requirements of the Public Utility Holding Company Act of 2005 other than the obligation to provide access to their books and records to the FERC and the CPUC for ratemaking purposes.

Federal Regulation

The Federal Energy Regulatory Commission

The FERC regulates the transmission of electricity and wholesale sales of electricity in interstate commerce and the transmission and sale of natural gas for resale in interstate commerce. The FERC also regulates interconnections of transmission systems with other electric systems and generation facilities, tariffs and conditions of service of regional transmission organizations, including the CAISO, and the terms and rates of wholesale electricity sales. The FERC has authority to impose fines of up to $1 million per day for violation of certain federal statutes and regulations. The FERC has jurisdiction over the Utility's electricity transmission revenue requirements and rates, the licensing of substantially all of the Utility's hydroelectric generation facilities, and the interstate sale and transportation of natural gas.

The FERC has the responsibility to approve and enforce mandatory standards governing the reliability of the nation's electricity transmission grid, including standards to protect the nation's bulk power system against potential disruptions from cyber and physical security breaches, to prevent market manipulation, and to supplement state transmission siting efforts in certain electric transmission corridors that are determined to be of national interest. The FERC certified the NERC as the nation's Electric Reliability Organization. The NERC is responsible for developing and enforcing electric reliability standards, subject to FERC approval. The FERC also has approved a delegation agreement under which the NERC has delegated enforcement authority for the geographic area known as the Western Interconnection to the Western Electricity Coordinating Council. The Utility must self-certify compliance to the WECC on an annual basis and the compliance program encourages self-reporting of violations. WECC staff, with participation by the NERC and the FERC, also performs a compliance audit of the Utility every three years. The FERC also has authorized the WECC and the NERC to impose fines up to $1 million per day, per violation.

The FERC also has adopted policies and rules to promote investment in energy infrastructure and lower costs for consumers through incentive ratemaking for transmission projects. In addition, the FERC's Order No. 1000 establishes electric transmission planning and cost allocation requirements for public utility transmission providers. Order No. 1000 requires public utility transmission providers to improve transmission planning processes and allocate costs for new transmission facilities to the beneficiaries of those facilities.

The CAISO is responsible for providing open access electricity transmission service on a non-discriminatory basis, planning transmission system additions, and ensuring the maintenance of adequate reserves of generation capacity.

The Nuclear Regulatory Commission

The NRC oversees the licensing, construction, operation and decommissioning of nuclear facilities, including the Utility's two nuclear generating units at Diablo Canyon and the Utility's retired nuclear generating unit at Humboldt Bay. NRC regulations require extensive monitoring and review of the safety, radiological, seismic, environmental, and security aspects of these facilities. In the event of non-compliance, the NRC has the authority to impose fines or to force a shutdown of a nuclear plant, or both. NRC safety and security requirements have, in the past, necessitated substantial capital expenditures at Diablo Canyon, and additional significant capital expenditures could be required in the future. For information about NRC matters affecting Diablo Canyon, including the status of the Utility's relicensing application see the information under the heading within MD&A entitled "Regulatory Matters–Diablo Canyon Nuclear Power Plant" in the 2013 Annual Report, which information is incorporated herein by reference.

The Pipeline and Hazardous Materials Safety Administration

The Utility also is subject to regulations adopted by the federal PHMSA that is within the United States Department of Transportation. The PHMSA develops and enforces regulations for the safe, reliable, and environmentally sound operation of the nation's pipeline transportation system and the shipment of hazardous materials. The PHMSA also has authorized the CPUC to enforce the federal pipeline safety standards over intrastate natural gas pipelines, as well as any state pipeline safety requirements that do not conflict with the federal requirements, through fines and/or injunctive relief.

The National Transportation Safety Board

The NTSB is an independent federal agency that is authorized to investigate pipeline accidents and certain transportation accidents that involve fatalities, substantial property damage, or significant environmental damage. The NTSB investigated the San Bruno accident and in August 2011 announced that it had determined the probable cause of the San Bruno accident placing the blame primarily on the Utility. The NTSB report recommended that the Utility take certain actions to improve the safety of its gas transmission system. The status of the Utility's implementation of the NTSB's recommendations is discussed under "Natural Gas Utility Operations" below.

State Regulation

The California Public Utilities Commission

The CPUC consists of five members appointed by the Governor of California and confirmed by the California State Senate for staggered six-year terms. The CPUC has jurisdiction over the rates and terms and conditions of service for the Utility's electricity and natural gas distribution operations, electricity generation, and natural gas transportation and storage services. The CPUC also has jurisdiction over the Utility's issuances of securities, dispositions of utility assets and facilities, energy purchases on behalf of the Utility's electricity and natural gas retail customers, rates of return, rates of depreciation, oversight of nuclear decommissioning, and aspects of the siting of facilities used in providing electric and natural gas utility service.

The CPUC enforces state laws that set forth safety requirements pertaining to the design, construction, testing, operation, and maintenance of utility gas gathering, transmission, and distribution pipeline systems, and for the safe operation of such pipelines and equipment. The CPUC has adopted many rules and regulations to implement state laws and policies, such as the laws relating to the development of renewable energy resources, demand response and public purpose programs, reduction of GHG emissions, and development of energy storage capacity. As discussed above, the CPUC also has been delegated authority to enforce compliance with certain federal regulations related to the safety of natural gas facilities. The CPUC has authority to impose fines for violating these state and federal laws, orders, or regulations of up to $50,000 per violation, per day. (See the discussion under the heading within MD&A

entitled “Natural Gas Matters” in the 2013 Annual Report for information about the CPUC’s pending enforcement proceedings against the Utility relating to the Utility’s gas operations, which discussion is incorporated herein by reference.)

In addition, California law enacted in 2013 requires the CPUC to develop a safety enforcement program that authorizes CPUC staff to issue citations for safety violations and assess fines subject to a CPUC-approved limit. The CPUC is required to implement the safety enforcement program for gas corporations by July 1, 2014 and for electric corporations by January 1, 2015. (See the discussion under the heading within MD&A entitled “Natural Gas Matters” in the 2013 Annual Report for information about the reports the Utility has filed to notify the CPUC staff of noncompliance with certain gas safety regulations.)

Ratemaking for retail sales from the Utility's generation facilities is under the jurisdiction of the CPUC. To the extent that this electricity is sold for resale into wholesale markets, however, it is under the ratemaking jurisdiction of the FERC. In addition, the CPUC has general jurisdiction over most of the Utility's operations, and regularly reviews the Utility's performance, using measures such as the frequency and duration of outages. The CPUC also conducts investigations into various matters, such as deregulation, competition, and the environment, in order to determine its future policies.

The CPUC has imposed conditions that govern the relationship between the Utility and PG&E Corporation and other affiliates. These conditions relate to finance, human resources, records and bookkeeping, and the transfer of customer information. Among other conditions, the financial conditions provide that the capital requirements of the Utility, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner, must be given first priority by PG&E Corporation's Board of Directors (known as the "first priority" condition). In addition, the Utility must maintain on average its CPUC-authorized utility capital structure, although it can request a waiver of this condition if an adverse financial event reduces the Utility's common equity component by 1% or more. The CPUC also has adopted rules governing transactions between California's CPUC-regulated electricity and gas utilities and certain of their affiliates that are not regulated by the CPUC primarily to prevent these affiliates from gaining an unfair advantage over their unaffiliated competitors.

The California Energy Resources Conservation and Development Commission

The California Energy Resources Conservation and Development Commission, commonly called the CEC, is the state's primary energy policy and planning agency. The CEC is responsible for licensing all thermal power plants over 50 MW, overseeing funding programs that support public interest energy research, advancing energy science and technology through research, development and demonstration, and providing market support to existing, new, and emerging renewable technologies. The CEC also is responsible for forecasts of future energy needs used by the CPUC in determining the adequacy of the utilities' electricity procurement plans.

The California Air Resources Board

The CARB is the state agency charged with setting and monitoring GHG and other emission limits. The CARB also is responsible for adopting and enforcing regulations to meet the AB 32, which requires the gradual reduction of GHG emissions in California to 1990 levels by 2020 on a schedule beginning in 2013. (For more information, see "Environmental Matters — Air Quality and Climate Change" below.)

Other Regulation

The Utility obtains permits, authorizations, and licenses in connection with the construction and operation of the Utility's generation facilities, electricity transmission lines, natural gas transportation pipelines, and gas compressor station facilities. These permits include discharge permits, various Air Pollution Control District permits, U.S. Department of Agriculture-Forest Service permits, FERC hydroelectric generation facility and transmission line licenses, and NRC licenses. (For more information, see "Environmental Matters — Water Quality" below.)

The Utility has franchise agreements with approximately 300 cities and counties that permit the Utility to install, operate, and maintain the Utility's electric and natural gas facilities in the public streets and roads. In exchange for the right to use public streets and roads, the Utility pays annual fees to the cities and counties. In most cases, the Utility's franchise agreements are for an indeterminate term, with no expiration date. The Utility has several franchise agreements that have a specified term of years, including an agreement with a large charter city.

The Utility also periodically obtains permits, authorizations, and licenses in connection with distribution of electricity and natural gas that grant the Utility rights to occupy and/or use public property for the operation of the Utility's business and to conduct certain related operations.

Competition in the Electricity Industry

At the federal level, the FERC is charged with developing rules to encourage fair and efficient competitive wholesale electric markets by employing best practices in market rules and reducing barriers to trade between markets and among regions. (See “Regulatory Environment–Federal Regulation” above for a description of some of these rules.) The FERC also has authority to prevent accumulation and exercise of market power by assuring that proposed mergers and acquisitions of public utility companies and their holding companies are in the public interest and by addressing market power in jurisdictional wholesale markets through its new powers to establish and enforce rules prohibiting market manipulation. The FERC also has issued rules on the interconnection of generators to require regulated transmission providers, such as the Utility or the CAISO, to use standard interconnection procedures and a standard agreement for generator interconnections. These rules are intended to limit opportunities for electric transmission providers to favor their own generation, facilitate market entry for generation competitors by streamlining and standardizing interconnection procedures, and encourage investment in generation and transmission.

In 1998, California became one of the first states to (1) allow customers of the California investor-owned electric utilities to purchase electricity from energy service providers other than the regulated utilities (referred to as "direct access") and (2) establish a competitive market for electricity generation in which generators and other electricity providers were permitted to charge market-based prices for wholesale electricity. The wholesale electricity market failed to function as anticipated leading to the 2000-2001 California energy crisis, the suspension of direct access, and the Utility's reorganization under Chapter 11 of the U.S. Bankruptcy Code. (For information about the unresolved disputed claims made by power suppliers in the Utility's Chapter 11 proceeding, see Note 12: Resolution of Remaining Chapter 11 Disputed Claims, of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated herein by reference.)

Current California law allows for the gradual phase-in of direct access subject to annual and overall limits (measured in GWh) that have been specified for each utility based roughly on each utility's highest level of direct access before the CPUC suspended direct access. A four-year phase-in period began in April 2010 to allow qualifying non-residential customers of the three California investor-owned electric utilities to purchase electricity from alternate service providers, subject to the limits. The Utility's maximum, 9,520 GWh, was reached in November 2013. Although the Utility's total amount of direct access load may increase due to natural load growth for existing direct access customers, further legislative action is required before new customers can be enrolled in excess of these limits.

In addition, the Utility's customers may, under certain circumstances, obtain power from a CCA instead of from the Utility. California law permits cities and counties and certain other public agencies to purchase and sell electricity for their local residents and businesses after they have registered as CCAs. Under these arrangements, the Utility continues to provide distribution, metering, and billing services to the customers of the CCAs and remains the electricity provider of last resort for those customers. The law provides that a CCA can procure electricity for all of its residents who do not affirmatively elect to continue to receive electricity from the Utility. Under the CPUC's rules, a surcharge is imposed on retail end-users of the CCA to prevent a shifting of costs to customers who continue to receive electricity from a utility. The law also authorizes the Utility to recover from each CCA any costs of implementing the program that are reasonably attributable to the CCA, and to recover from all customers any costs of implementing the program not reasonably attributable to a CCA. Approximately 125,000 customers are now receiving commodity service from the Marin Energy Authority, a CCA. Sonoma Clean Power, another CCA, is expected to begin service to a subset of customers in Sonoma County in May 2014.

In some circumstances, governmental entities such as cities and irrigation districts, which have authority under the state constitution or state statute to provide retail electric service, seek to acquire the Utility's distribution facilities. For example, South San Joaquin Irrigation District has indicated that, if it receives the requested authority to provide electric distribution service in and around certain cities (Manteca, Ripon, and Escalon), it will seek to acquire the Utility's distribution facilities, either under a consensual transaction, or via eminent domain.

It is also possible that technological developments could pose challenges for traditional utilities. In particular, technology-related cost declines and sustained federal or state subsidies could make the combination of "distributed generation" and storage a viable, cost-effective alternative to the Utility's bundled electric service. In addition, the levels of self-generation of electricity by customers (primarily solar installations) and the use of customer net energy metering, which allows self-generating customers to receive bill credits at the full retail rate, are increasing.

Although the CPUC has established ratemaking mechanisms that allow the Utility to collect some non-bypassable or fixed charges from those who procure electricity from alternate sources, rates for the Utility's remaining customers could increase as alternative energy providers (CCAs or local government agencies) and alternative energy sources (self-generation and storage, distributed generation, electric vehicles) become more prevalent. Increasing rate pressure on remaining customers could, in turn, cause more customers to seek alternative energy providers or sources, further exacerbating the Utility's rate challenges. New state legislation that became effective on January 1, 2014

(Assembly Bill 327) gave the CPUC new authority to reduce the cost shift associated with customers installing renewable distributed generation under the net energy metering rules.

In addition, the Utility competes with third parties to make various capital investments such as new utility-owned generation facilities, electric transmission projects, SmartGrid electric reliability projects, and distributed generation technologies. The Utility generally participates through a competitive requests-for-offers process that is subject to the oversight of the CPUC or the FERC. If the Utility is selected as the winning bidder, the Utility submits the executed contract for regulatory approval and cost recovery authorization.

Competition in the Natural Gas Industry

Under the FERC's rules, interstate natural gas pipeline companies are required to divide their services into separate gas commodity sales, transportation, and storage services and must provide transportation service whether or not the customer (often a local gas distribution company) buys the natural gas from these companies. The Utility's natural gas pipelines are located within the State of California and are exempt from most of the FERC's rules and regulations applicable to interstate pipelines; the Utility's pipeline operations are instead subject to the jurisdiction of the CPUC.

The Utility's gas transmission and storage system has operated under the CPUC-approved "Gas Accord" market structure since 1998 which largely mimics the regulatory framework required by the FERC for interstate gas pipelines. (See "Ratemaking Mechanisms" below.) The CPUC divides the Utility's natural gas customers into two categories: "core" customers, who are primarily small commercial and residential customers, and "non-core" customers, who are primarily industrial, large commercial, and electric generation customers. Although most of the Utility's core customers purchase natural gas directly from the Utility (along with transportation and distribution services as bundled services), core customers have the option to purchase natural gas from independent, unregulated natural gas marketers. Most of the Utility's noncore customers make natural gas supply arrangements directly with producers or purchase natural gas from marketers.

Non-core customers have access to capacity rights for firm service on the Utility's natural gas pipeline, as well as interruptible (or "as-available") services. All services are offered on a nondiscriminatory basis to any creditworthy customer. This market structure has resulted in a robust wholesale gas commodity market at the Utility's "Citygate," which refers to the non-physical interconnection between the big "backbone" gas transmission system and the smaller downstream local transmission systems.

The Utility competes with other natural gas pipeline companies for customers transporting natural gas into the southern California market on the basis of transportation rates, access to competitively priced supplies of natural gas, and the quality and reliability of transportation services. The most important competitive factor affecting the Utility's market share for transportation of natural gas to the southern California market is the total delivered cost of western Canadian and U.S. Rocky Mountains natural gas delivered to northern California, relative to the total delivered cost of natural gas from the southwestern United States. In general, when the total cost of western Canadian and U.S. Rocky Mountains natural gas delivered to northern California increases relative to other competing natural gas sources, the Utility's market share of transportation services into southern California decreases. The Utility also competes for storage services with other third-party storage providers, primarily in northern California.

In addition, the Utility competes with third parties to make various capital investments such as new natural gas storage facilities. The Utility generally participates through a competitive requests-for-offers process that is subject to the oversight of the CPUC or the FERC. If the Utility is selected as the winning bidder, the Utility submits the executed contract for regulatory approval and cost recovery authorization.

Ratemaking Mechanisms

The Utility's rates for electricity and natural gas utility services are based on its costs of providing service ("cost-of-service ratemaking"). Before setting rates, the CPUC and the FERC conduct proceedings to determine the annual amount of revenue ("revenue requirements") that the Utility is authorized to collect from its customers to recover its reasonable operating and capital costs (depreciation, tax, and financing expenses) of providing utility services. The Utility's revenue requirements are set based on forecasted costs. Differences in the amount or timing between forecast costs and actual costs could negatively affect the Utility's ability to earn its authorized return.

To develop retail rates, the revenue requirements are allocated among customer classes which are mainly residential, commercial, industrial, and agricultural. Rate changes become effective prospectively on or after the date of CPUC or FERC decisions. Most rate changes approved by the CPUC throughout the year are consolidated to take effect on the first day of the following year.

California Assembly Bill 327, effective on January 1, 2014, repealed prior law that restricted the CPUC's ability to change residential electric rates and to reduce the level of rate assistance for certain low-income customers. AB 327 also authorized the CPUC to approve fixed charges to be collected from residential customers. The CPUC has ordered the California investor-owned utilities, including the Utility, to file proposals for changing residential rates that are consistent with the new law. The current procedural schedule calls for a final decision in the first half of 2014 to approve changes to the Utility's residential electric rates for summer 2014, and a final decision by year-end 2014 to approve broader changes in residential electric rates.

While the CPUC generally uses cost-of-service ratemaking to develop revenue requirements and rates, it selectively uses incentive ratemaking, which bases rates on the extent to which the utilities meet objective or fixed standards or goals, such as energy efficiency goals, instead of on the cost of providing service. See "Public Purpose and Customer Programs" below.

Electricity and Natural Gas Distribution and Electricity Generation Operations

General Rate Cases

The GRC is the primary proceeding in which the CPUC determines the amount of revenue requirements that the Utility is authorized to collect from customers to recover the Utility's anticipated costs related to its electricity and natural gas distribution and electricity generation operations and to provide the Utility an opportunity to earn its authorized rate of return. The CPUC generally conducts a GRC every three years. The CPUC approves the annual revenue requirements for the first year (or "test year") of the GRC period and typically authorizes the Utility to receive annual increases (known as "attrition adjustments") in revenue requirements for the subsequent years of the GRC period. Attrition rate adjustments are provided to avoid a reduction in earnings due to, among other things, inflation and increases in invested capital. Intervenors in the Utility's GRC include the CPUC's ORA and TURN, who generally represent the overall interests of customers, as well as a myriad of other intervenors who represent more limited interests.

In November 2012, the Utility filed its 2014 GRC application with the CPUC for rates effective from 2014 through 2016. The CPUC has concluded evidentiary hearings and briefing in the 2014 GRC and the Utility is now waiting for the CPUC to issue a proposed decision. For more information see the heading within MD&A entitled "Regulatory Matters – 2014 General Rate Case" in the 2013 Annual Report, which information is incorporated herein by reference.

In November 2013, the CPUC opened a proceeding to consider modifications to the processing and content of GRCs (and for the Utility's GT&S rate cases) to better integrate and prioritize safety, reliability, and security issues by developing a risk-based decision-making framework for the CPUC to use in evaluating the utilities' requested revenue requirements. The CPUC also will consider whether to change the current three-year rate case cycle and whether to retain the requirement that the ORA review a draft of the utilities' GRC applications prior to filing. A decision is expected to be issued in late 2014.

Cost of Capital Proceedings

The CPUC authorizes the Utility's capital structure (i.e., the relative weightings of common equity, preferred equity, and debt) and the authorized rates of return on each component that the Utility may earn on its electric generation, electric and natural gas distribution, and natural gas transmission and storage rate base. The CPUC has authorized the Utility's capital structure through 2015, consisting of 52% common equity, 47% long-term debt, and 1% preferred stock. The CPUC also authorized the Utility to earn a ROE of 10.40% effective January 1, 2013, compared to the 11.35% previously authorized. The Utility's ROE can be automatically adjusted if the 12-month October-through-September average of the Moody's Investors Service long-term Baa utility bond index increases or decreases by more than 1.00% as compared to the applicable benchmark. If the adjustment mechanism is triggered, the Utility's authorized ROE, beginning January 1 of the following year, would be adjusted by one-half of the difference between the index and the benchmark. Additionally, the Utility's authorized costs of long-term debt and preferred stock would be updated to reflect actual August month-end embedded costs and forecasted interest rates for variable long-term debt, as well as new long-term debt and preferred stock scheduled to be issued. In any year where the 12-month average yield triggers an automatic ROE adjustment, that average would become the new benchmark.

The Utility will file its next full cost of capital application in April 2015 for the 2016 test year.

Rate Recovery of Costs of Electricity Generation Resources

California investor-owned electric utilities are required to use the principles of "least-cost dispatch" in managing electric generation resources to meet customer demand for electricity. The utilities are also responsible for procuring electricity required to meet customer demand, plus applicable reserve margins, that are not satisfied from their own generation facilities and existing electricity contracts. To accomplish this, each utility must submit a ten-year procurement plan to the CPUC for approval. Each procurement plan must be designed to use the State of California's preferred loading order to meet the forecasted demand (i.e., increases in future demand will be offset through energy efficiency programs, demand response programs, renewable generation resources, distributed generation resources, and new conventional generation). The CPUC approved the Utility's electricity procurement plan in January 2012 covering 2011 through 2020 and approved the Utility's GHG compliance instrument procurement plan in April 2012.

California law allows electric utilities to recover the costs incurred in compliance with their CPUC-approved electricity procurement plans without further after-the-fact reasonableness review. To the extent the Utility's electricity purchases are not in compliance with the CPUC-approved plan, costs associated with those purchases may be disallowed. The Utility recovers its electricity procurement costs through the ERRA, a balancing account authorized by the CPUC, that tracks the difference between (1) billed and unbilled ERRA revenues and (2) electric procurement costs incurred under the Utility's authorized procurement plans. Each year, to determine the rates used to collect ERRA revenues, the CPUC reviews the Utility's forecasted procurement costs related to power purchase agreements, hedging, and generation fuel expense and approves a forecasted revenue requirement.

On December 19, 2013, the CPUC approved the Utility's forecast of 2014 procurement costs and associated revenue requirement. Changes in rates to reflect the approved revenue requirement became effective on January 1, 2014. (The CPUC may adjust a utility's retail electricity rates at any time when the forecasted aggregate over-collections or under-collections in the ERRA exceed five percent of its prior year electricity procurement revenues.) The CPUC also performs an annual compliance review to ensure that (1) the Utility prudently administered the contracts that were entered into in accordance with its CPUC-approved procurement plans, (2) utilized the principles of least-cost dispatch in managing its electric generation resources, and (3) prudently operated its own generation facilities.

Costs Incurred Under New Power Purchase Agreements

The CPUC has approved various power purchase agreements that the Utility has entered into with third parties in accordance with the Utility's CPUC-approved procurement plan, the renewable energy mandate, and resource adequacy requirements and has authorized the Utility to recover costs associated with these contracts through the ERRA.

For new non-renewable generation purchased from third parties under power purchase agreements, the Utility may also recover any above-market costs through either (1) a non-bypassable customer charge or (2) the allocation of the "net capacity costs" (i.e., contract price less energy revenues) to all "benefiting customers" in the Utility's service territory, including direct access customers and CCA customers under certain circumstances. The non-bypassable charge can be imposed from the date of signing a power purchase agreement and can last for ten years from the date the new generation unit comes on line or for the term of the contract, whichever is less. Utilities are allowed to justify a cost recovery period longer than ten years on a case-by-case basis. If a utility uses the net capacity cost allocation method, the net capacity costs are allocated for the term of the contract. To use the net capacity allocation method, the CPUC must determine that a resource was needed to meet system or local area reliability needs for the benefit of all distribution customers. The CPUC can decide whether to require an energy auction for resources subject to the net capacity cost allocation.

For renewable generation purchased from third parties under power purchase agreements, the Utility may also recover any above-market costs through the imposition of a non-bypassable charge on customers.

Costs of Utility-Owned Generation Resource Projects

The Utility's recovery of its capital costs and non-fuel operating and maintenance costs for Utility-owned generation facilities is addressed in the Utility's GRC. From time to time, the Utility may also request the CPUC to authorize additional revenue requirements to recover capital investments and operating costs associated with new Utility-owned generation facilities in a separate ratemaking proceeding. The Utility may recover any above-market costs associated with new utility-owned generation resources in a manner similar to the recovery of above-market costs for non-renewable generation purchases described above. The recovery of above-market costs is typically addressed in the CPUC order approving a specific utility-owned generation project.

Electricity Transmission

The Utility's electricity transmission revenue requirements and its wholesale and retail transmission rates are subject to authorization by the FERC. The Utility has two main sources of transmission revenues: (1) charges under the Utility's TO tariff and (2) charges under specific contracts with wholesale transmission customers that the Utility entered into before the CAISO began its operations in 1998. These wholesale customers are referred to as existing transmission contract customers and are charged individualized rates based on the terms of their contracts. Other customers pay transmission rates that are established by the FERC in the Utility's TO tariff rate cases. These FERC-approved rates are included by the CPUC in the Utility's retail electric rates and are collected from retail electric customers receiving bundled service.

TO Rate Cases

The primary FERC ratemaking proceeding to determine the amount of revenue requirements that the Utility is authorized to recover for its electric transmission costs and to earn its return on equity is the TO rate case. The Utility generally files a TO rate case every year. The Utility is typically able to charge new rates, subject to refund, before the outcome of the FERC ratemaking review process. See the information within MD&A entitled "Electric Transmission Owner Rate Cases" in the 2013 Annual Report, which information is incorporated herein by reference.

The Utility's TO tariff includes several rate components. The primary component consists of base transmission rates intended to recover the Utility's operating and maintenance expenses, depreciation and amortization expenses, interest expense, tax expense, and return on equity. The Utility derives the majority of the Utility's transmission revenue from base transmission rates. Another component consists of rates that reflect credits and charges from the CAISO for transmission revenues received by the CAISO for providing wholesale wheeling service (i.e., the transfer of electricity that is being sold in the wholesale market) to third parties using the Utility's transmission facilities and charges related to the cost of providing service to existing transmission contract customers under specific contracts. The CAISO also imposes a transmission access charge on the Utility for use of the CAISO-controlled electric transmission grid in serving its customers, which are recovered from the Utility's retail customers as part of transmission rates.

Natural Gas Transmission

Costs Incurred Under the Pipeline Safety Enhancement Plan

Following the San Bruno accident, the CPUC began a rulemaking proceeding in 2011 to adopt new safety and reliability regulations for natural gas transmission and distribution pipelines in California and the related ratemaking mechanisms. As part of this proceeding, the CPUC ordered the California natural gas utilities to submit proposed plans to modernize and upgrade their natural gas transmission systems, including cost forecasts and ratemaking proposals. In December 2012, the CPUC approved most of the projects proposed in the Utility's PSEP but disallowed the Utility's request for rate recovery of a significant portion of PSEP-related costs that the Utility forecasted it would incur through 2014. The CPUC authorized the Utility to recover costs, subject to the adopted capital and expense amounts, for activities including pipeline strength testing, pipeline replacement, in-line inspection, and the installation of automated valves. The CPUC prohibited the Utility from recovering the costs of pressure testing pipeline placed into service after January 1, 1956 for which the Utility is unable to produce pressure test records. The CPUC ordered the Utility to file an update PSEP application after the Utility completes its search and review of records relating to pipeline pressure validation for all 6,750 miles of the Utility's natural gas transmission pipelines. On October 29, 2013, the Utility submitted its update application to present the results of its completed records search and review and to request approval of adjusted revenue requirements for 2014. Based on the information obtained through the records search and review, the Utility has proposed to change the scope and prioritization of PSEP work, including deferring some projects to after 2014 and accelerating other projects. See the information under the headings within MD&A entitled "Natural Gas Matters" in the 2013 Annual Report, which information is incorporated herein by reference.

Natural Gas Transmission and Storage Rate Cases

The CPUC determines the Utility's authorized revenue requirements and rates for its natural gas transmission and storage services in a separate rate case called the GT&S rate case. The CPUC's decision in the most recent GT&S rate case approved a settlement agreement, known as the Gas Accord V, which set the Utility's rates and associated revenue requirements for natural gas transmission and storage services from January 1, 2011 through December 31, 2014. In December 2013, the Utility filed its 2015 GT&S rate case application with the CPUC covering 2015 through 2017. The Utility's forecasts for the 2015 GT&S rate case period are consistent with state law, which requires gas corporations to develop a plan to identify and minimize hazards and systemic risk for public and employee safety. The forecasts include the continuation of work begun in the Utility's PSEP, such as testing pipelines to verify safe operating pressures, replacing older pipelines, installing more valves, and inspecting the interior of more pipelines. The Utility forecasts that it will incur certain costs that it will not seek to recover from customers. See the information under the heading within MD&A entitled "2015 Gas Transmission and Storage Rate Case" in the 2013 Annual Report, which information is incorporated herein by reference.

Under the current ratemaking mechanisms (which have been in existence since 1998 when the first Gas Accord settlement agreement became effective), the Utility's ability to recover a portion of its revenue requirements depends on throughput volumes, gas prices, and the extent to which large industrial customers, large commercial customers, and other shippers contract for firm transmission services. In its 2015 GT&S rate case application, the Utility has proposed eliminating these current mechanisms and that the CPUC establish new two-way balancing accounts to allow the Utility to record differences between actual customer billings and the Utility's authorized revenue requirements for natural gas transmission and storage revenues. Any over-collections would be returned to customers and any under-collections would be paid by customers.

Under the current ratemaking mechanisms, revenue requirements allocated to core customers are decoupled and recovered through balancing accounts that ensure the Utility recovers only its adopted amounts, no more or less. Revenue requirements allocated to non-core customers are subject to a sharing mechanism. Annually, differences between the authorized revenue requirements and actual customer billings are shared between customers and the Utility's shareholders to varying degrees, depending on the type of service. The Utility is currently at risk for approximately 25% of its total authorized GT&S revenue requirements. In its 2015 GT&S rate case application, the Utility has proposed to discontinue the sharing mechanism and to, instead, recover its non-core revenue requirements in the same decoupled manner as its core revenue requirements though existing balancing accounts. Non-core customers are typically large commercial, industrial, electric generation or wholesale customers who meet required usage requirements. These customers must obtain their own gas procurement and are subject to curtailment.

Biennial Cost Allocation Proceeding

Certain of the Utility's natural gas distribution costs and balancing account balances are allocated to customers in the CPUC's Biennial Cost Allocation Proceeding. This proceeding normally occurs every two years and is updated in the interim year for purposes of adjusting natural gas rates to recover from customers any under-collection, or refund to customers any over-collection, in the balancing accounts. Balancing accounts for gas distribution and other authorized expenses accumulate differences between authorized amounts and actual revenues.

Natural Gas Procurement

The Utility recovers the cost of gas purchased on behalf of core customers, as well as some core hedging costs, through its retail gas rates subject to a limited incentive mechanism based on a market-priced benchmark. The Utility recovers the cost of gas used in generation facilities as a cost of electricity that is recovered through retail electricity rates. (For more information, see Note 9: Derivatives, of the Notes to the Consolidated Financial Statements in the

2013 Annual Report, which information is incorporated herein by reference).

Interstate and Canadian Natural Gas Transportation

The Utility has a number of agreements with interstate and Canadian third-party transportation service providers to transport natural gas from the points at which the Utility takes delivery of natural gas (typically in Canada, the U.S. Rocky Mountains, and the southwestern United States) to the points at which the Utility's natural gas transportation system begins. These are governed by tariffs that detail rates, rules, and terms of service for the provision of natural gas transportation services to the Utility on interstate and Canadian pipelines. United States tariffs are approved for each pipeline for service to all of its shippers, including the Utility, by the FERC in a FERC ratemaking review process, and the applicable Canadian tariffs are approved by the Alberta Utilities Commission and the National Energy Board. The transportation costs the Utility incurs under these agreements are recovered through CPUC-approved rates as core natural gas procurement costs or as electricity procurement costs. For more information, see the discussion below under "Natural Gas Utility Operations — Interstate and Canadian Natural Gas Transportation Services Agreements" below.

Electric Utility Operations

During 2013, the Utility made significant capital investments to modernize and upgrade its electric transmission and distribution infrastructure to extend the life of or replace existing infrastructure; to maintain and improve system reliability, safety, and customer service; to integrate more renewable energy resources; to increase capacity; and add new infrastructure to meet customer demand growth. The Utility improved the reliability of its system by adding emergency capacity at substations, increasing distribution system automation, upgrading poor performing circuits, performing targeted asset replacement, and improving service outage restoration processes. The Utility also has been working to accelerate pole replacement and maintenance of its overhead and underground electric facilities and to increase the use of wireless devices that allow the Utility to monitor the performance of the electric system and respond more quickly to power disruptions.

The Utility's advanced metering infrastructure supports the development of a "smart grid" in California, part of a nationwide effort to improve and modernize the nation's electric system by combining advanced communications and controls to create a responsive and resilient energy delivery network. The Utility has substantially completed the installation of an advanced metering infrastructure throughout its service territory in 2012. (As permitted by CPUC rules, customers may choose not to have an advanced meter installed.) The new infrastructure uses SmartMeterTM technology that can measure energy use in hourly or quarter-hourly increments, allow customers to track energy usage throughout the billing month and thus enable greater customer control over electricity costs. Usage data is collected through a wireless communications network and transmitted to the Utility's information system where the data is stored and used for billing and other Utility business purposes.

The Utility is also incorporating the latest "smart grid" technology in parts of its service territory by installing automated switches that reduce outage duration and the number of customers affected by outages. The Utility also received regulatory approval to pilot and test new "smart grid" technologies that have the potential to support the provision of safe, reliable and affordable electric service. Over the next several years, the Utility plans to undertake various "smart grid" projects and invest in "smart grid" technologies.

Electricity Resources

The Utility is required to maintain physical generating capacity adequate to meet its customers' load, including peak demand and planning and operating reserves, deliverable to the locations and at times as may be necessary to provide reliable electric service. The Utility is required to dispatch, or schedule, all of the electricity resources within its portfolio in the most cost-effective way. The following table shows the percentage of the Utility's total actual deliveries of electricity to customers in 2013 represented by each major electricity resource, and further discussed below.

Total 2013 Actual Electricity Delivered – 75,705 GWh:

	Percent of Bundled Retail Sales			
Owned Generation Facilities				
Nuclear	23.8	%		
Small Hydroelectric	1.2	%		
Large Hydroelectric	9.4	%		
Fossil fuel-fired	8.1	%		
Solar	0.4	%		
Total			42.9	%
Qualifying Facilities				
Renewable	4.1	%		
Non-Renewable	8.9	%		
Total			13.0	%
Irrigation Districts and Water Agencies				
Small Hydroelectric	0.2	%		
Large Hydroelectric	1.9	%		
Total			2.1	%
Other Third-Party Purchase Agreements				
Renewable	16.6	%		
Large Hydroelectric	0.6	%		
Non-Renewable	13.0	%		
Total			30.2	%
Others, Net (1)			11.8	%
Total			100	%

(1) Mainly comprised of net CAISO open market purchases, offset by transmission and distribution related system losses.

Owned Generation Facilities

At December 31, 2013, the Utility owned the following generation facilities, all located in California, listed by energy source and further described below:

Generation Type	County Location	Number of Units	Net Operating Capacity (MW)
Nuclear:			

Diablo Canyon	San Luis Obispo	2	2,240
Hydroelectric:			
Conventional	16 counties in northern and central California	104	2,670
Helms pumped storage	Fresno	3	1,212
Hydroelectric subtotal:		107	3,882
Fossil fuel-fired:			
Colusa Generating Station	Colusa	1	657
Gateway Generating Station	Contra Costa	1	580
Humboldt Bay Generating Station	Humboldt	10	163
CSU East Bay Fuel Cell	Alameda	1	1.4
SF State Fuel Cell	San Francisco	2	1.6
Fossil fuel-fired subtotal:		15	1,403
Photovoltaic:	Various	13	152
Total		137	7,677

Diablo Canyon Power Plant. The Utility's Diablo Canyon power plant consists of two nuclear power reactor units, Units 1 and 2. For the year ended December 31, 2013, the Utility’s Diablo Canyon power plant achieved an average overall capacity factor of approximately 92%. The NRC operating license for Unit 1 expires in November 2024, and the NRC operating license for Unit 2 expires in August 2025. For more information on matters affecting Diablo Canyon, see the section of MD&A entitled “Regulatory Matters–Diablo Canyon Nuclear Power Plant” in the 2013 Annual Report, which information is incorporated herein by reference. The ability of the Utility to produce nuclear generation depends on the availability of nuclear fuel. The Utility has entered into various purchase agreements for nuclear fuel that are intended to ensure long-term fuel supply. For more information about these agreements, see Note 14: Commitments and Contingencies — Nuclear Fuel Agreements, of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated herein by reference.

The following table outlines the Diablo Canyon power plant's refueling schedule for the next five years. The Diablo Canyon power plant refueling outages are typically scheduled every 20 months. The average length of a refueling outage over the last five years has been approximately 49.5 days. The actual refueling schedule and outage duration will depend on the scope of the work required for a particular outage and other factors.

	2014	2015	2016	2017	2018
Unit 1					
Refueling	February	September	-	April	-
Startup	March	November	-	May	-
Unit 2					
Refueling	October	-	May	-	February
Startup	November	-	June	-	March

Hydroelectric Generation Facilities. The Utility's hydroelectric system consists of 107 generating units at 67 powerhouses, including the Helms pumped storage facility. Most of the Utility's hydroelectric generation units are classified as "large" hydro facilities, as their powerhouse capacity exceeds 30 MW. The system includes 98 reservoirs, 73 diversions, 169 dams, 173 miles of canals, 43 miles of flumes, 132 miles of tunnels, 65 miles of pipe (penstocks, siphons and low head pipes), and 4 miles of natural waterways, and approximately 140,000 acres of fee-owned land. The system also includes water rights as specified in 89 permits or licenses and 160 statements of water diversion and use. The Helms pumped storage facility consists of three motor/generator units.

All of the Utility's powerhouses are licensed by the FERC (except for three small powerhouses not subject to FERC licensing requirements), with license terms between 30 and 50 years. The Utility is in the process of renewing hydroelectric licenses associated with capacity of approximately 1,138 MW and surrendering the hydroelectric license associated with the Kilarc-Cow Creek Project which has a capacity of 5 MW. Although the original licenses associated with 1,070 MW of the 1,138 MW have expired, the licenses are automatically renewed each year until completion of the relicensing process. Licenses associated with approximately 2,812 MW of hydroelectric power will expire between 2014 and 2047.

Fossil Fuel-fired Generation Facilities. The Utility's natural gas-fired generation facilities include the Colusa Generating Station, the Gateway Generating Station, and the Humboldt Bay generating station. In addition, the Utility owns and operates three fuel cell sites in the Bay Area.

Photovoltaic Facilities. The Utility's operational PV facilities include the Five Points solar station (15 MW), the Westside solar station (15 MW), the Stroud solar station (20 MW), the Huron solar station (20 MW), the Cantua solar station (20 MW), the Giffen solar station (10 MW), the Gates solar station (20 MW), the West Gates solar station (10 MW) and the Guernsey solar station (20 MW). All of these facilities are located in Fresno County, except for the Guernsey solar station, which is located in Kings County.

Generation Resources from Third Parties

Qualifying Facility Power Purchase Agreements. In accordance with the Public Utility Regulatory Policies Act of 1978, the CPUC required electric utilities to purchase energy and capacity from independent power producers with generation facilities that meet the statutory definition of a qualifying facility. QFs primarily include small production facilities whose primary energy sources are co-generation facilities that produce combined heat and power and renewable generation facilities. As of December 31, 2013, the Utility had agreements with 170 QFs that are in operation, which expire at various dates between 2014 and 2028.

Irrigation Districts and Water Agencies. The Utility also has entered into agreements with various irrigation districts and water agencies to purchase hydroelectric power. These agreements require the Utility to make semi-annual fixed minimum payments as well as variable payments based on the operating and maintenance costs incurred by the irrigation districts and water agencies. These contracts will expire on various dates between 2014 and 2030.

Other Third-Party Power Purchase Agreements. The Utility has entered into several power purchase agreements for renewable and conventional generation resources, including tolling agreements and resource adequacy agreements.

For more information regarding the Utility's power purchase agreements, see Note 14: Commitments and Contingencies — Third-Party Power Purchase Agreements, of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated herein by reference.

Renewable Generation Resources

California law requires load-serving entities, such as the Utility, to gradually increase the amount of renewable energy they deliver to their customers to at least 33% of their total annual retail sales. The RPS program, which became effective in December 2011, established three multi-year compliance periods that have gradually increasing RPS targets: 2011 through 2013, 2014 through 2016, and 2017 through 2020. After 2020, the RPS compliance periods will be annual. In 2013, the California law that established the RPS program was amended to allow the CPUC to set higher RPS targets. The CPUC is conducting a rulemaking proceeding to consider, among other issues, whether and how to increase the RPS targets. Renewable generation resources, for purposes of the RPS program, include bioenergy such as biogas and biomass, certain (primarily small) hydroelectric facilities and efficiency improvements, wind, solar, and geothermal energy. The Utility has made substantial financial commitments under third-party renewable energy contracts to meet its RPS requirements. The Utility forecasts that it will comply with its RPS requirements for the first and second compliance periods based on its current portfolio of executed contracts. The costs incurred by the Utility under third-party contracts to meet RPS requirements are expected to be recovered with other procurement costs through rates. The costs of Utility-owned renewable generation projects will be recoverable through traditional cost-of-service ratemaking mechanisms provided that costs do not exceed the maximum amounts authorized by the CPUC for the respective project.

During 2013, most renewable energy deliveries resulted from third party power purchase agreements and QF agreements. Additional renewable resources included the Utility's small hydroelectric and solar facilities and certain irrigation district contracts (small hydroelectric facilities). (Under California law, generally only small hydroelectric generation resources (30 MW or less) can qualify as a renewable resource for purposes of meeting the RPS mandate, with some exceptions. Most of the Utility's hydroelectric generating units have a capacity in excess of the 30-MW threshold and do not qualify as RPS-eligible resources.)

Total 2013 renewable deliveries are stated in the table below.

Type	GWh	Percent of Bundled Retail Sales	
Biopower	3,239	4.3	%
Geothermal	3,693	4.9	%
Wind	4,904	6.5	%
RPS-Eligible Hydroelectric	1,581	2.1	%
Solar	3,613	4.7	%
Total	17,030	22.5	%

For more information regarding the Utility's renewable energy contracts, see Note 14: Commitments and Contingencies — Third-Party Power Purchase Agreements, of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated herein by reference.

Electricity Transmission

At December 31, 2013, the Utility owned approximately 18,115 circuit miles of interconnected transmission lines operated at voltages of 500 kV to 60 kV. The Utility also operated 91 electric transmission substations with a capacity of approximately 62,289 MVA. The Utility's electric transmission system is interconnected with electric power systems in the WECC, which includes many western states, Alberta and British Columbia, Canada, and parts of Mexico.

The CAISO, which is regulated by the FERC, controls the operation of the transmission system and provides open access transmission service on a nondiscriminatory basis. The CAISO also is responsible for ensuring that the reliability of the transmission system is maintained. The Utility acts as its own scheduling coordinator to schedule electricity deliveries to the transmission grid. The Utility also acts as a scheduling coordinator to deliver electricity produced by several governmental entities to the transmission grid under contracts the Utility entered into with these entities before the CAISO commenced operation in 1998. In addition, under the mandatory reliability standards implemented by the FERC, all users, owners, and operators of the transmission system, including the Utility, are also responsible for maintaining reliability through compliance with the reliability standards. See the discussion of reliability standards under "The Utility's Regulatory Environment — Federal Regulation" above.

In November 2013, the Utility, MidAmerican Transmission LLC, and Citizens Energy Corporation were selected by CAISO to develop a new 70-mile transmission line to address the growing power demand in the greater Fresno area. The 230-kV line will span across Fresno, Madera and Kings counties, running from the Gates to Gregg substations, which are owned and operated by the Utility. In addition to increased power, the new line will help reduce the number and duration of power outages, create jobs and support economic development, and bolster efforts to integrate clean, renewable energy onto the grid. The transmission line would be operational no later than 2022 and could come on line earlier.

During 2013, the Utility upgraded several critical substations and re-conductored some transmission lines to improve maintenance and operating flexibility, reliability and safety, including the installation or replacement of 8 transmission substation transformers. The Utility expects to undertake various additional transmission projects over the next few years to upgrade and expand the Utility's transmission system and increase capacity in order to accommodate system load growth, to secure access to renewable generation resources, to replace aging or obsolete equipment, and to improve system reliability. The Utility also has taken steps to improve the physical security of its transmission substations and equipment following the attack on one of its transmission substations in April 2013 which caused significant damage.

Electricity Distribution

The Utility's electricity distribution network consists of approximately 141,000 circuit miles of distribution lines (of which approximately 20% are underground and approximately 80% are overhead), 58 transmission-switching substations, and 603 distribution substations. The Utility's distribution network interconnects with the Utility's transmission system primarily at transmission switching substations and distribution substations where transformers and switching equipment reduce the high-voltage transmission levels at which the electricity transmission system transmits electricity, ranging from 500 kV to 60 kV, to lower voltages, ranging from 44 kV to 2.4 kV, suitable for distribution to the Utility's customers.

The distribution substations serve as the central hubs of the Utility's electricity distribution network and consist of transformers, voltage regulation equipment, protective devices, and structural equipment. Emanating from each substation are primary and secondary distribution lines connected to local transformers and switching equipment that link distribution lines and provide delivery to end-users. In some cases, the Utility sells electricity from its distribution lines or other facilities to entities, such as municipal and other utilities, that then resell the electricity. In April 2013, the Utility began construction on the first of three new electric distribution control centers that will house new smart grid technology, enhancing electric reliability for customers. Located in Concord, California, the 37,000-square-foot facility is expected to be completed in 2014.

In 2013, the Utility replaced more than nearly 100,000 feet of underground cable, primarily in San Francisco and East Bay, replaced 100,686 feet of overhead wire, and installed or replaced 19 distribution substation transformer banks to improve reliability and provide capacity to accommodate growing demand. The Utility plans to continue performing work to improve the reliability and safety of its electricity distribution operations in 2014.

Electricity Operating Statistics

The following table shows certain of the Utility's operating statistics from 2009 to 2013 for electricity sold or delivered, including the classification of revenues by type of service.

	2013	2012	2011	2010	2009
Customers (average for the year)	5,243,216	5,214,170	5,188,638	5,155,724	5,137,240
Deliveries (in GWh) (1)	86,513	86,113	81,255	79,634	72,385
Revenues (in millions):					
Residential	$5,091	$4,953	$4,778	$4,795	$4,759
Commercial	4,905	4,735	4,732	4,823	4,538
Industrial	1,388	1,408	1,379	1,424	1,392
Agricultural	1,021	901	692	736	770
Public street and highway lighting	75	79	77	79	74
Other	(128)	(11)	94	(1,178)	(1,700)
Subtotal	12,352	12,065	11,752	10,679	9,833
Regulatory balancing accounts	137	(51)	(151)	(35)	424
Total electricity operating revenues	$12,489	$12,014	$11,601	$10,644	$10,257
Other Data:					
Average annual residential usage (kWh)	6,752	5,961	6,799	6,843	6,953
Average billed revenues (per kWh):					
Residential	$0.1643	$0.1594	$0.1548	$0.1560	$0.1524
Commercial	0.1499	0.1449	0.1441	0.1468	0.1377
Industrial	0.0928	0.917	0.951	0.988	0.940
Agricultural	0.1454	0.1458	0.1475	0.1451	0.1327

Net plant investment per customer	$6,002	$4,919	$5,045	$4,728	$4,336

(1) These amounts include electricity provided to direct access customers who procure their own supplies of electricity.

Natural Gas Utility Operations

During 2013, the Utility continued to make significant progress on efforts to improve the safety and reliability of its natural gas operations, including performing extensive pipeline testing and monitoring, and replacing and upgrading equipment. Much of this work is part of the Utility's pipeline safety enhancement plan, approved by the CPUC in December 2012, to modernize and upgrade its natural gas transmission system to meet new, industry-wide safety standards. Many of these improvement efforts satisfy recommendations made to the Utility by the NTSB and the CPUC in 2010 and 2011 following their investigations into the San Bruno accident. The Utility has satisfied nine of the twelve NTSB recommendations. The Utility continues to make progress on the remaining three longer-term recommendations.

Since work began on the PSEP and other gas transmission work in 2011, the Utility has verified 657 miles of transmission pipeline through hydrostatic pressure tests or records verification, replaced 127 miles of transmission pipeline, installed 134 automated valves, and collected and digitized more than 3.5 million pipeline records. In July 2013, the Utility completed its search and review of records relating to pipeline pressure validation for all approximately 6,750 miles of its natural gas transmission system. (See the information within MD&A under the heading "Natural Gas Matters" in the 2013 Annual Report, which information is incorporated herein by reference.) In 2013, as part of the Utility's multi-year effort to identify and remove encroachments (e.g. building structures and vegetation overgrowth) from transmission pipeline rights-of-way, the Utility completed a "centerline" mapping survey of its entire gas transmission system to locate, mark, and map the center of all transmission pipelines. The Utility also continued to improve the integrity of transmission pipelines, which included retrofitting approximately 190 miles of pipeline in 2013 to accommodate in-line inspection tools.

The Utility has also implemented a new distribution integrity management program designed to enhance operations and improve the overall safety of the gas distribution system. The Utility has analyzed and replaced a total of 53 miles of Aldyl-A plastic pipeline in 2012 and 2013 and plans to replace 33 additional miles by the end of 2014. It also updated the geographic information system with information on approximately 5,600 miles of Aldyl-A pipeline, including additional pipeline and service attribute information. The Utility completed additional distribution leak surveys in 2013 (in addition to complying with regular distribution leak survey requirements) and repaired approximately 41,000 leaks of all grades.

In August 2013, the Utility opened its new 42,000-square-foot control center in San Ramon, California to monitor and control all aspects of its natural gas system across its service area. The Utility has continued to improve operations by utilizing modern tools and technologies to inspect pipelines, detect gas leaks, and provide real-time access to detailed maps of the Utility's underground gas system. The Utility has improved its supervisory controls and data acquisition system to better detect pipeline leaks and breaks and improve its integrity management program, including incorporating new analysis tools to identify and assess risks to pipeline integrity. The Utility has also implemented a system to enable employees and contractors to report potential pipeline integrity issues and track corrective actions taken. Finally, the Utility has significantly improved the speed at which it responds to gas odor calls.

Natural Gas System Assets

The Utility owns and operates an integrated natural gas transportation, storage, and distribution system that includes most of northern and central California. At December 31, 2013, the Utility's natural gas system consisted of approximately 42,559 miles of distribution pipelines, over 6,000 miles of backbone and local transmission pipelines, and various storage facilities. The Utility owns and operates eight natural gas compressor stations which receive, store and move natural gas through the Utility's pipelines. The Utility's backbone transmission system, composed primarily of Lines 300, 400, and 401, is used to transport gas from the Utility's interconnection with interstate pipelines, other local distribution companies, and California gas fields to the Utility's local transmission and distribution systems. Line 300 interconnects with pipeline systems located in the U.S. Southwest and the Rocky Mountains that are owned by third parties (Transwestern Pipeline Company, El Paso Natural Gas Company, Questar Southern Trails Pipeline Company, and Kern River Pipeline Company). Line 300 has a receipt capacity of approximately 1.1 Bcf per day. Line 400 and 401 interconnect at the California-Oregon border with the pipeline systems owned by GTN and Ruby Pipeline, LLC. This line has a receipt capacity at the border of approximately 2.2 Bcf per day. Through interconnections with other interstate pipelines, the Utility can receive natural gas from all the major natural gas basins in western North America, including basins in western Canada, the Rocky Mountains, and the southwestern United States. The Utility also is supplied by natural gas fields in California.

The Utility owns and operates three underground natural gas storage fields connected to the Utility's transmission and storage system and has a 25% interest in the new Gill Ranch Storage Field. These storage fields and the Utility's Gill Ranch share have a combined firm capacity of approximately 48.7 Bcf. In addition, three independent storage operators are interconnected to the Utility's northern California transportation system.

Natural Gas Services

The CPUC divides the Utility’s on-system natural gas customers into two categories for the purpose of determining service reliability: core and non-core customers. This classification is based largely on a customer’s annual natural gas usage. The core customer class is comprised mainly of residential and small commercial natural gas customers. The non-core customer class is comprised of industrial, large commercial, and electric generation natural gas customers. In 2013, core customers represented more than 99% of the Utility’s total natural gas customers and 37% of its total natural gas deliveries, while non-core customers comprised less than 1% of the Utility’s total natural gas customers and 63% of its total natural gas deliveries. In addition to deliveries discussed above, the Utility delivers gas to off-system customers (i.e., outside of the Utility’s service territory) and to third-party natural gas storage customers.

The Utility provides natural gas transportation services to all core and non-core customers connected to the Utility’s system in its service territory. Core customers can purchase natural gas procurement service (i.e., natural gas supply) from either the Utility or alternate energy service providers. When the Utility provides both transportation and procurement services, the Utility refers to the combined service as “bundled” natural gas service. Currently, more than 91% of core customers, representing nearly 80% of the annual core market demand, receive bundled natural gas service from the Utility.

The Utility does not provide procurement service to large non-core customers such as electricity generators, QF co-generators, enhanced oil recovery customers, refiners, and other large non-core customers. However, some smaller non-core customers are permitted to elect to receive core service, including procurement service, from the Utility if they agree to receive such service for a minimum of five years. Core service to non-core customers is subject to these restrictions to protect core procurement customers from price increases that could otherwise result if the Utility incurred costs to reinforce its pipeline system and take other measures to provide core service reliability on a short-term basis to serve new load from non-core customers.

The Utility offers backbone gas transmission, gas delivery (local transmission and distribution), and gas storage services as separate and distinct services to its non-core customers. Access to the Utility's backbone gas transmission system is available for all natural gas marketers and shippers, as well as non-core customers.

Natural Gas Supplies

The Utility purchases natural gas to serve its core customers directly from producers and marketers in both Canada and the United States. The contract lengths and natural gas sources of the Utility’s portfolio of natural gas purchase contracts have fluctuated generally based on market conditions. During 2013, the Utility purchased approximately 240,414 MMcf of natural gas (net of the sale of excess supply of gas). Substantially all this natural gas was purchased under contracts with a term of one year or less. The Utility’s largest individual supplier represented approximately 13% of the total natural gas volume the Utility purchased during 2013.

Interstate and Canadian Natural Gas Transportation Services Agreements

The Utility has a number of arrangements with interstate and Canadian third-party transportation service providers to serve core customers' service demands. The Utility has firm transportation agreements for delivery of natural gas from western Canada to the United States-Canada border with TransCanada NOVA Gas Transmission, Ltd. and TransCanada Foothills Pipe Lines Ltd., B.C. System. These companies’ pipeline systems connect at the border to the pipeline system owned by GTN, which provides natural gas transportation services to a point of interconnection with the Utility’s natural gas transportation system on the Oregon-California border near Malin, Oregon. The Utility also has firm transportation agreements with Ruby Pipeline, LLC to transport this gas from the U.S Rocky Mountains to the interconnection point with the Utility’s natural gas transportation system in the area of Malin, Oregon, at the California border, and firm transportation agreements with Transwestern Pipeline Company, LLC and El Paso Natural

Gas Company to transport this natural gas from supply points in the U.S. Southwest to interconnection points with the Utility's natural gas transportation system in the area of California near Topock, Arizona. The Utility also has a transportation agreement with Kern River Gas Transmission Company to transport gas from the U.S. Rocky Mountains to the interconnect point with the Utility's natural gas system in the area of Daggett, CA.

Natural Gas Operating Statistics

The following table shows the Utility's operating statistics from 2009 through 2013 (excluding subsidiaries) for natural gas, including the classification of revenues by type of service.

	2013	2012	2011	2010	2009
Customers (average for the year)	4,378,797	4,353,278	4,327,407	4,295,741	4,271,007
Gas purchased (MMcf)	240,414	247,792	279,157	270,228	264,314
Average price of natural gas purchased	$3.29	$2.45	$3.69	$4.07	$3.57
Bundled gas sales (MMcf):					
Residential	181,775	185,376	201,109	195,195	195,217
Commercial	46,668	47,341	52,230	53,921	57,550
Total	228,443	232,717	253,339	249,116	252,767
Revenues (in millions):					
Bundled gas sales:					
Residential	$1,870	$1,852	$2,089	$1,991	$1,953
Commercial	395	383	464	474	496
Regulatory balancing accounts	240	221	295	305	289
Other	44	66	102	49	55
Bundled gas revenues	2,549	2,522	2,950	2,819	2,793
Transportation service only revenue	555	499	400	377	349
Operating revenues	$3,104	$3,021	$3,350	$3,196	$3,142
Selected Statistics:					
Average annual residential usage (Mcf)	44	45	49	48	48
Average billed bundled gas sales revenues per Mcf:					
Residential	$10.29	$9.99	$10.39	$10.20	$10.00
Commercial	8.47	8.09	8.89	8.79	8.62
Net plant investment per customer	$2,234	$1,696	$1,721	$1,637	$1,557

Public Purpose and Customer Programs

California law has established various public purpose programs related to energy efficiency, energy research and development, and renewable energy resources. These programs include the CSI and other self-generation programs, as discussed under “Self-Generation Incentive Program and California Solar Initiative,” below. California law requires the CPUC to authorize funding for these programs through the collection of rate surcharges and other rate components. Additionally, the CPUC has authorized funding for energy savings assistance and demand response programs. For 2013, the Utility was authorized revenue requirements of $724 million from electric customers and $160 million from gas customers to fund public purpose and other programs.

Energy Efficiency Programs

The Utility’s energy efficiency programs are designed to encourage the manufacture, design, distribution, and customer use of energy efficient appliances, other energy-using equipment and energy management products to meet energy savings goals in California. The CPUC has authorized a total of $823 million to fund the Utility’s 2013 and 2014 energy efficiency programs, including programs administered by the Marin Energy Authority, a CCA, and a regional network of San Francisco Bay area cities and counties.

On December 20, 2012, the CPUC approved an energy efficiency incentive mechanism to reward the Utility and other California energy utilities for the successful implementation of their 2010-2012 energy efficiency programs. The mechanism provides each utility with an earnings rate composed of a 5% management fee based on qualified program expenditures and an additional performance bonus of up to 1%. The Utility's earnings rate for the 2010-2012 energy efficiency program cycle is 5.68%. The CPUC has awarded the Utility $21 million and $22 million for program years 2010 and 2011, respectively. The utilities will file their incentive claims based on the CPUC-audited 2012 program expenditures in the third quarter of 2014 for approval by the CPUC in the fourth quarter of 2014.

On September 5, 2013, the CPUC approved a new energy efficiency incentive mechanism designed to reward the Utility and the other California investor-owned utilities for the successful implementation of their energy efficiency portfolios for 2013 and beyond. The mechanism provides each utility with an ability to earn shareholder incentives through four separate earnings categories. The mechanism includes a cap on earnings for the Utility of approximately $41 million annually for 2013 and 2014.

Demand Response Programs

Demand response programs provide financial incentives and other benefits to participating customers to curtail on-peak energy use. In April 2012, the CPUC authorized the Utility to collect $192 million to fund its 2012-2014 demand response programs. On January 16, 2014, the CPUC approved a 2015 and 2016 bridge extension of the existing programs while it determines the enhanced role of demand response in meeting California's resource planning needs and operational requirements, with the exact amount of funding to be determined in a future CPUC decision. Pending a decision, funding will remain capped at the same level as the current 2013-2014 demand response budget.

Self-Generation Incentive Program and California Solar Initiative

The Utility administers the self-generation incentive program authorized by the CPUC to provide incentives to electricity and gas customers who install certain types of clean or renewable distributed generation and energy storage resources that meet all or a portion of their onsite energy usage. The CPUC approved annual funding for the self-generation incentive program of $36 million through 2014, with any carryover funds to be administered through 2015. The Utility also administers the CSI in its service territory. The CPUC has authorized the Utility to collect approximately $1.1 billion from 2007 through 2016 to fund customer incentives for the installation of retail solar energy projects to serve onsite load, as well as to fund research, development, and demonstration activities, and administration expenses. The current overall objective of this initiative is to install 3,000 MW (through both California investor-owned electric utilities and municipal electric utilities) through 2016. The California legislature approved additional funding of $108 million for the low income CSI program and the CPUC will provide direction on this extension in 2014.

Low-Income Energy Efficiency Programs and California Alternate Rates for Energy

The CPUC has authorized the Utility to collect approximately $469 million to support the Utility's energy efficiency programs for low-income and fixed-income customers over 2012 through 2014. The Utility also provides a discount rate called the California Alternate Rates for Energy for low-income customers. This rate subsidy is paid for by the Utility's other customers. During any given year, the extent of the subsidy for customers collectively depends upon the number of customers participating in the program and their actual energy usage. In 2013, the amount of this subsidy was approximately $833 million. The CPUC also authorized the Utility to recover approximately $45 million in administrative costs relating to the California Alternate Rates for Energy subsidy through 2014.

Environmental Regulation

The Utility's operations are subject to extensive federal, state and local laws and requirements relating to the protection of the environment and the safety and health of the Utility's personnel and the public. These laws and requirements relate to a broad range of activities, including the discharge of pollutants into the air, water, and soil; the reporting and reduction of CO2 and other GHG emissions; the remediation of hazardous and radioactive substances; the transportation, handling, storage and disposal of spent nuclear fuel; and the environmental impacts of land use, including endangered species and habitat protection.

The penalties for violation of these laws and requirements can be severe and may include significant fines, damages, and criminal or civil sanctions. These laws and requirements also may require the Utility, under certain circumstances, to interrupt or curtail operations. To comply with these laws and requirements, the Utility may need to spend substantial amounts from time to time to construct, acquire, modify, or replace equipment, acquire permits and/or emission allowances or other emission credits for facility operations and clean-up, or decommission waste disposal areas at the Utility's current or former facilities and at third-party sites where the Utility's wastes may have been discharged. The actual amount of costs that the Utility will incur is subject to many factors, including changing laws and regulations, the ultimate outcome of complex factual investigations, evolving technologies, selection of compliance alternatives, the nature and extent of required remediation, the extent of the facility owner's responsibility, the availability of recoveries or contributions from third parties, and the development of market-based strategies to address climate change. Generally, the Utility has recovered the costs of complying with environmental laws and regulations in the Utility's rates, subject to reasonableness review. Environmental costs associated with the clean-up of most sites that contain hazardous substances are subject to a special ratemaking mechanism described in Note 14: Commitments and Contingencies—Environmental Remediation Contingencies, of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated by reference.

Air Quality and Climate Change

The Utility's electricity generation plants, natural gas pipeline operations, fleet, and fuel storage tanks are subject to numerous air pollution control laws, including the federal Clean Air Act, as well as state and local statutes. These laws and regulations cover, among other pollutants, those contributing to the formation of ground-level ozone, carbon monoxide, SO2, NOx, GHGs, and particulate matter.

Federal Regulation. At the federal level, the EPA is charged with implementation and enforcement of the Clean Air Act. Although there have been several legislative attempts to address climate change through imposition of nationwide regulatory limits on GHG emissions, comprehensive federal legislation has not yet been enacted.. In the absence of federal legislative action, the EPA has used its existing authority under the Clean Air Act to address GHG emissions, including establishing an annual GHG reporting requirement. The Utility files annual GHG emission reports with the EPA covering its electric and gas operations in compliance with the EPA’s reporting requirement. In addition, in January 2014, the EPA published draft regulations under section 111(b) of the Clean Air Act to control GHG emissions from new fossil fuel-fired power plants. While these draft regulations as presently written do not apply to the Utility’s power plants currently in operation or under construction, it is possible that the final regulations may affect the design, construction, operation and cost of future fossil fuel-fired power plants. The EPA has also announced that it intends to issue draft regulations applicable to GHG emissions from existing power plants under section 111(d) of the Clean Air Act in June of 2014.

State Regulation. AB 32 requires the gradual reduction of state-wide GHG emissions to the 1990 level by 2020. The CARB is the state agency charged with monitoring GHG levels and adopting regulations to implement and enforce AB 32. The CARB established a state-wide GHG 1990 emissions baseline of 427 million metric tons of CO2 (or its equivalent) to serve as the 2020 emissions limit for the state of California. The CARB has approved various regulations to implement AB 32, including GHG emissions reporting and a state-wide, comprehensive “cap and trade” program that sets gradually declining limits (or “caps”) on the amount of GHGs that may be emitted by the major sources of GHG emissions.

The cap and trade program’s first two-year compliance period, which began January 1, 2013, applies to the electricity generation and large industrial sectors. The next three-year compliance period, from January 1, 2015 through December 31, 2017, will expand to include the natural gas supply and transportation sectors, effectively covering all the capped sectors until 2020. During each year of the program, the CARB will issue emission allowances (i.e., the rights to emit GHGs) equal to the amount of GHGs emissions allowed for that year. Emitters can obtain allowances from the CARB at quarterly auctions held by the CARB or from third parties or exchanges in the market for trading GHG allowances. The CARB is allocating a fixed number of allowances (which will decrease each year) for free to regulated electric distribution utilities, including the Utility, for the benefit of their electricity customers. The utilities are required to consign their electricity-related allowances for auction by the CARB. The CPUC has ordered the utilities to allocate their electricity-related auction revenues among certain classes of their customers. Although the CPUC has previously authorized the utilities to recover their electricity related GHG compliance costs through rates, the recovery of these costs has been temporarily deferred until May 2014. In addition, the CARB may allocate a number of allowances for free to natural gas suppliers, including the Utility, for the benefit of the Utility’s natural gas customers. In anticipation of the Utility’s expanded compliance obligations for natural gas suppliers beginning January 1, 2015, the Utility has filed requests at the CPUC for authority to recover the natural gas supplier-related compliance costs from natural gas customers on an annual basis effective January 1, 2015. The Utility expects all costs and revenues associated with GHG cap-and-trade to be passed through to customers.

Increasing use of renewable energy supplies also is expected to help reduce GHG emissions in California. (For more information, see “Renewable Generation Resources” above.)

Climate Change Mitigation and Adaptation Strategies. During 2013, the Utility continued its programs to develop strategies to mitigate the impact of the Utility's operations (including customer energy usage) on the environment and to develop its strategy to plan for the actions that it will need to take to adapt to the likely impacts that climate change will have on the Utility's future operations. With respect to electric operations, climate scientists project that, sometime in the next several decades, climate change will lead to increased electricity demand due to more extreme and frequent hot weather events. Climate scientists also predict that climate change will result in significant reductions in snowpack in parts of the Sierra Nevada Mountains. This impact could, in turn, affect the Utility's hydroelectric generation. At this time, the Utility does not anticipate that reductions in Sierra Nevada snowpack will have a significant impact on its hydroelectric generation, due in large part to its adaptation strategies. For example, one adaptation strategy the Utility is developing is a combination of operating changes that may include, but are not limited to, higher winter carryover reservoir storage levels, reduced conveyance flows in canals and flumes in response to an increased portion of precipitation falling as rain rather than snow, and reduced discretionary reservoir water releases during the late spring and summer. If the Utility is not successful in fully adapting to projected reductions in snowpack over the coming decades, it may become necessary to replace some of its hydroelectric generation with electricity from other sources, including GHG-emitting natural gas-fired power plants.

With respect to natural gas operations, both safety-related pipeline hydrotesting/strength testing and normal pipeline maintenance and operations, releases the GHG methane to the atmosphere. The Utility has taken proactive steps to reduce the release of methane by implementing techniques including drafting and cross-compression which reduces the pressures and volumes of natural gas within pipelines prior to venting. In addition, the Utility continues to replace a substantial portion of its older cast iron, steel and plastic distribution pipelines and steel gas transmission mains with new pipe, which reduces leakage. In 2013, the Utility implemented a proactive natural gas leak repair program, 40,676 gas leaks were identified, graded, prioritized and repaired. The primary reason for this effort was public safety, however, eliminating gas leaks results in a positive impact to the environment.

The Utility believes its strategies to reduce GHG emissions—such as energy efficiency and demand response programs, infrastructure improvements, and the support of renewable energy development—are also effective strategies for adapting to the expected increased demand for electricity in extreme hot weather events likely to result from climate change. PG&E Corporation and the Utility are also assessing the benefits and challenges associated with various climate change policies and identifying how a comprehensive program can be structured to mitigate overall costs to customers and the economy as a whole while ensuring that the environmental objectives of the program are met.

Emissions Data

PG&E Corporation and the Utility track and report their annual environmental performance results across a broad spectrum of areas. As a result of the time necessary for a thorough, third-party verification of the Utility's GHG emissions, emissions data for 2012 are the most recent data available. The Utility reports its GHG emissions to the CARB. The Utility also voluntarily reports its GHG emissions to The Climate Registry, a non-profit organization that has a reporting and measurement standard applicable to most industry sectors across North America, which enables the Utility to publicly report GHG emissions not covered by mandatory reporting requirements. The Utility's third-party verified voluntary GHG inventory for 2012 totaled more than 57 million metric tonnes of CO2-e, which includes approximately 38 million metric tonnes CO2-e from customer natural gas use.

Beginning with its 2010 emissions, the Utility reports the GHG emissions from its facilities and operations to the EPA under its mandatory reporting requirements. PG&E Corporation and the Utility also publish third-party-verified GHG emissions data in their annual Corporate Responsibility and Sustainability Report.

2012 Emissions Reported to the California Air Resources Board

The following table shows the GHG emissions data the Utility reported to the CARB under AB 32.

Source	Amount (metric tonnes CO2 – equivalent)
Fossil Fuel-Fired Plants (1)	2,466,851
Natural Gas Compressor Stations (2)	351,878
Distribution Fugitive Natural Gas Emissions	222,995
Customer Natural Gas Use (3)	42,434,940
Total	45,476,664

(1) Includes nitrous oxide and methane emissions from the Utility's generating stations; does not include de minimis emissions.
(2) Includes compressor stations emitting more than 25,000 metric tonnes of CO2-e annually; does not include de minimis emissions.
(3) Includes emissions from the combustion of natural gas delivered to all entities on the Utility's distribution system, with the exception of gas delivered to other natural gas local distribution companies. This figure does not represent the Utility's compliance obligation under AB 32, which will be equivalent to the above reported value less the fuel that is delivered to covered entities as calculated by the CARB.

Benchmarking GHG Emissions for Delivered Electricity

The Utility's third-party-verified CO2 emissions rate associated with the electricity delivered to customers in 2012 was 445 pounds of CO2 per MWh. The Utility's 2012 emissions rate as compared to the national and California averages for electric utilities is shown in the following table:

	Amount (Pounds of CO2 per MWh)
U.S. Average (1)	1,216

California's Average (1)	659
Pacific Gas and Electric Company (2)	445

(1) Source: Environmental Protection Agency eGRID 2012 Version 1.0, which contains year 2009 information configured to reflect the electric power industry's current structure as of May 10, 2012. This is the most up-to-date information available from EPA.

(2) Since the Utility purchases a portion of its electricity from the wholesale market, the Utility is not able to track some of its delivered electricity back to a specific generator. Therefore, there is some unavoidable uncertainty in the Utility's total emissions and the Utility's emission rate for delivered electricity.

Emissions Data for Utility-Owned Generation

In addition to GHG emissions data provided above, the table below sets forth information about the GHG and other emissions from the Utility's owned generation facilities. The Utility's owned generation (primarily nuclear and hydroelectric facilities) comprised more than 40% of the Utility's delivered electricity in 2012. The Utility's fossil fuel-fired generation comprised approximately 8% of the Utility's delivered electricity in 2012.

	2012	2011
Total NOx Emissions (tons)	158	144
NOx Emissions Rates (pounds/MWh)		
Fossil Fuel-Fired Plants	0.05	0.06
All Plants	0.01	0.008
Total SO2 Emissions (tons)	15	12
SO2 Emissions Rates (pounds/MWh)		
Fossil Fuel-Fired Plants	0.005	0.005
All Plants	0.0009	0.0007
Total CO2 Emissions (metric tons)	2,464,464	2,024,206
CO2 Emissions Rates (pounds/MWh)		
Fossil Fuel-Fired Plants	864	875
All Plants	172	126
Other Emissions Statistics		
Sulfur Hexafluoride Emissions		
Total Sulfur Hexafluoride Emissions (metric tons CO2-e)	63,127	70,052
Sulfur Hexafluoride Emissions Leak Rate	1.5 %	1.7 %

Water Quality

The EPA published draft regulations in April 2011 to implement the requirements of the federal Clean Water Act that requires cooling water intake structures at electric power plants, such as the nuclear generation facilities at Diablo Canyon, reflect the best technology available to minimize adverse environmental impacts. In June 2012, the EPA proposed changes to these draft regulations which, if adopted, would provide more flexibility in complying with some of the requirements. It is currently uncertain when the EPA will issue final regulations.

At the state level, the California Water Board has adopted a policy on once-through cooling that generally requires the installation of cooling towers or other significant measures to reduce the impact on marine life from existing power generation facilities in California by at least 85%. The California Water Board has appointed a committee to evaluate the feasibility and cost of using alternative technologies to achieve compliance at nuclear power plants, including Diablo Canyon. The committee's consultant is expected to submit a final report to the California Water Board in 2014. If the California Water Board requires the installation of cooling towers that the Utility believes are not technically or economically feasible, the Utility may be forced to cease operations at Diablo Canyon and may incur a material charge. Even if the Utility is not required to install cooling towers, it could incur significant costs to comply with alternative compliances measures or to make payments to support various environmental mitigation projects. The Utility would seek to recover such costs in rates. The Utility's Diablo Canyon operations must be in compliance with the California Water Board's policy by December 31, 2024.

Hazardous Waste Compliance and Remediation

The Utility's facilities are subject to the requirements issued by the EPA under the federal Resource Conservation and Recovery Act and the CERCLA, as well as other state hazardous waste laws and other environmental requirements. CERCLA and similar state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site, and in some cases corporate successors to the operators or arrangers. Under CERCLA, these persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, damages to natural resources, and the costs of required health studies. In the ordinary course of the Utility's operations, the Utility generates waste that falls within CERCLA's definition of hazardous substances and, as a result, has been and may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

The Utility has a comprehensive program in place to comply with federal, state, and local laws and regulations related to hazardous materials and hazardous waste compliance, remediation activities, and other environmental requirements. The Utility assesses and monitors, on an ongoing basis, measures that may be necessary to comply with these laws and regulations and implements changes to its program as deemed appropriate. The Utility’s remediation activities are overseen by the California Department of Toxic Substances Control, several California regional water quality control boards, and various other federal, state, and local agencies.

The Utility has been, and may be, required to pay for environmental remediation at sites where the Utility has been, or may be, a potentially responsible party under CERCLA and similar state environmental laws. These sites include former manufactured gas plant sites, power plant sites, gas gathering sites, sites where natural gas compressor stations are located, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous substances. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if it did not deposit those substances on the site. Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, estimated costs may vary significantly from actual costs, and the amount of additional future costs may be material to results of operations in the period in which they are recognized. For more information about environmental remediation liabilities, see the sections within MD&A entitled “Environmental Matters,” “Critical Accounting Polices,” and Note 14: Commitments and Contingencies– Environmental Remediation Contingencies, of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated herein by reference.

Generation Facilities

Operations at the Utility's current and former generation facilities may have resulted in contaminated soil or groundwater. Although the Utility sold most of its geothermal and fossil fuel-fired plants, in many cases the Utility retained pre-closing environmental liability under various environmental laws. The Utility currently is investigating or remediating several such sites with the oversight of various governmental agencies. Fossil fuel-fired Units 1 and 2 of the Utility’s Humboldt Bay power plant shut down in September 2010, and are now in the decommissioning process along with the nuclear Unit 3, which was shut down in 1976. The Utility has entered into a voluntary cleanup agreement with the California Department of Toxic Substances Control and is currently completing a soil and groundwater investigation to determine what soil and groundwater remediation may be necessary.

Former Manufactured Gas Plant Sites

The Utility is assessing whether and to what extent remedial action may be necessary to mitigate potential hazards posed by certain retired MGP sites. During their operation, from the mid-1800s through the early 1900s, MGPs produced lampblack and coal tar residues. The residues from these operations, which may remain at some sites, contain chemical compounds that now are classified as hazardous. The Utility has been coordinating with environmental agencies and third-party owners to evaluate and take appropriate action to mitigate any potential environmental concerns at 41 MGP sites that the Utility owned or operated in the past.

Natural Gas Compressor Stations

Groundwater at the Utility's Hinkley and Topock natural gas compressor stations contains hexavalent chromium as a result of the Utility's past operating practices. The Utility is responsible for remediating this groundwater contamination and for abating the effects of the contamination on the environment. The Utility has incurred significant environmental liabilities associated with these sites. For more information about the Utility's remediation and abatement efforts and related liabilities, see Note 14: Commitments and Contingencies–Environmental Remediation Contingencies of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated herein by reference.

Nuclear Fuel Disposal

Under the Nuclear Waste Policy Act of 1982, the DOE and electric utilities with commercial nuclear power plants were authorized to enter into contracts under which the DOE would be required to dispose of the utilities' spent nuclear fuel and high-level radioactive waste by January 1998, in exchange for fees paid by the utilities. The DOE has been unable to meet its contractual obligation with the Utility to dispose of nuclear waste from the Utility's two nuclear generating units at Diablo Canyon and the retired nuclear facility at Humboldt Bay Unit 3. As a result, the Utility constructed an interim dry cask storage facility to store spent fuel at Diablo Canyon through at least 2024, and a separate facility at Humboldt Bay. The Utility and other nuclear power plant owners sued the DOE to recover the costs that they incurred to construct interim storage facilities for spent nuclear fuel.

On September 5, 2012, the U.S. Department of Justice and the Utility executed a settlement agreement that awarded the Utility $266 million for spent fuel storage costs incurred through December 31, 2010. In 2013, the Utility was awarded an additional $29 million for costs incurred between January 2011 and May 2012. These proceeds were recorded in a regulatory balancing account and are being refunded to customers through rates. On January 31, 2014, the U.S. Department of Justice and the Utility executed an addendum extending the term of the settlement agreement for an additional three years, through 2016. The amended settlement agreement does not address costs incurred for spent fuel storage after 2016 and such costs could be the subject to future litigation. Considerable uncertainty continues to exist regarding when and whether the DOE will meet its contractual obligation to the Utility and other nuclear power plant owners to dispose of spent fuel.

Nuclear Decommissioning

The Utility's nuclear power facilities consist of two units at Diablo Canyon and the retired facility at Humboldt Bay Unit 3. Nuclear decommissioning requires 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. The Utility files an application with the CPUC every three years requesting approval of the Utility's estimated decommissioning costs and authorization to recover the estimated costs through rates. Nuclear decommissioning charges collected through rates are held in nuclear decommissioning trusts to be used for the eventual decommissioning of each nuclear unit. (See the discussion of the 2012 Nuclear Decommissioning Cost Triennal Proceeding in the section of MD&A entitled "Regulatory Matters–Diablo Canyon Nuclear Power Plant" and Note 2: Summary of Significant Accounting Policies of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated herein by reference.)

Endangered Species

Many of the Utility's facilities and operations are located in, or pass through, areas that are designated as critical habitats for federal, or state-listed endangered, threatened, or sensitive species. The Utility may be required to incur additional costs or be subjected to additional restrictions on operations if additional threatened or endangered species are listed or additional critical habitats are designated at or near the Utility's facilities or operations. The Utility is seeking to secure "habitat conservation plans" to ensure long-term compliance with state and federal endangered species acts. The Utility expects that it will be able to recover costs of complying with state and federal endangered species acts through rates.

ITEM 1A. Risk Factors

A discussion of the significant risks associated with investments in the securities of PG&E Corporation and the Utility appears within MD&A under the heading "Risk Factors" in the 2013 Annual Report, which information is incorporated herein by reference.

ITEM 1B. Unresolved Staff Comments

None.

ITEM 2. Properties

The Utility owns or has obtained the right to occupy and/or use real property comprising the Utility's electricity and natural gas distribution facilities, natural gas gathering facilities and generation facilities, and natural gas and electricity transmission facilities, which are described above under “Electric Utility Operations” and “Natural Gas Utility Operations” which information is incorporated herein by reference. The Utility occupies or uses real property that it does not own primarily through various leases, easements, rights-of-way, permits, or licenses from private landowners or governmental authorities. In total, the Utility occupies 11.0 million square feet of real property, including 8.6 million square feet that the Utility owns. The Utility’s corporate headquarters comprises approximately 1.7 million square feet located in several Utility-owned buildings in San Francisco, California. PG&E Corporation also has entered into leases for approximately 87,000 square feet of office space in San Francisco, California. Leases for 40,000 square feet will expire in 2014 and the remaining leases will expire in 2022.

The Utility currently owns approximately 170,000 acres of land, including approximately 140,000 acres of watershed lands. Pursuant to its 2002 Settlement Agreement with the CPUC, the Utility agreed to permanently preserve six “beneficial public values” on all its watershed lands through conservation easements or equivalent protections, and to make up to 44,000 acres of its watershed lands available for donation to public entities or qualified non-profit conservation organizations through its Land Conservation Commitment. The Utility will not donate watershed lands that contain the Utility's or a joint licensee's hydroelectric generation facilities, but this land will be encumbered with conservation easements. Pursuant to the 2002 Settlement Agreement, the Pacific Forest Watershed Lands Stewardship Council was formed to oversee the development and implementation of a Land Conservation Plan that articulates the long-term management objectives for these watershed lands. The Council is governed by an 18-member board of directors, one of whom is appointed by the Utility. The other members represent a range of diverse stakeholders in the watershed lands. The Utility’s goal is to implement all the Land Conservation Commitment transactions by the end of 2017, subject to securing all required regulatory approvals.

ITEM 3. Legal Proceedings

In addition to the following legal proceedings, PG&E Corporation and the Utility are involved in various legal proceedings in the ordinary course of their business. For more information regarding PG&E Corporation’s and the Utility’s liability for legal matters, see Note 14: Commitments and Contingencies of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated herein by reference.

Diablo Canyon Power Plant

The Utility's Diablo Canyon power plant employs a “once-through” cooling water system that is regulated under a Clean Water Act permit issued by the Central Coast Board. This permit allows the Diablo Canyon power plant to discharge the cooling water at a temperature no more than 22 degrees above the temperature of the ambient receiving water, and requires that the beneficial uses of the water be protected. The beneficial uses of water in this region include industrial water supply, marine and wildlife habitat, shellfish harvesting, and preservation of rare and endangered species. In January 2000, the Central Coast Board issued a proposed draft cease and desist order alleging that, although the temperature limit has never been exceeded, the Utility's Diablo Canyon power plant's discharge was not protective of beneficial uses.

In October 2000, the Utility and the Central Coast Board reached a tentative settlement under which the Central Coast Board agreed to find that the Utility's discharge of cooling water from the Diablo Canyon power plant protects beneficial uses and that the intake technology reflects the best technology available, as defined in the federal Clean Water Act. As part of the tentative settlement, the Utility agreed to take measures to preserve certain acreage north of the plant and to fund approximately $6 million in environmental projects and future environmental monitoring related to coastal resources. On March 21, 2003, the Central Coast Board voted to accept the settlement agreement. On June 17, 2003, the settlement agreement was executed by the Utility, the Central Coast Board and the California Attorney General's Office. A condition to the effectiveness of the settlement agreement is that the Central Coast Board renew Diablo Canyon's permit.

At its July 10, 2003 meeting, the Central Coast Board did not renew the permit and continued the permit renewal hearing indefinitely. Several Central Coast Board members indicated that they no longer supported the settlement agreement, and the Central Coast Board requested a team of independent scientists, as part of a technical working group, to develop additional information on possible mitigation measures for Central Coast Board staff. In January 2005, the Central Coast Board published the scientists' draft report recommending several such mitigation measures. If the Central Coast Board adopts the scientists' recommendations, and if the Utility ultimately is required to implement the projects proposed in the draft report, it could incur costs of up to approximately $30 million. The Utility would seek to recover these costs through rates charged to customers.

The EPA published draft regulations in April 2011 to implement the requirements of SECTION 316(b) of the federal Clean Water Act that requires cooling water intake structures at electric power plants, such as the nuclear generation facilities at Diablo Canyon, to reflect the best technology available to minimize adverse environmental impacts. In June 2012, the EPA proposed changes to these draft regulations which, if adopted, would provide more flexibility in complying with some of the requirements. It is currently uncertain when the EPA will issue final regulations. As part of the implementation process for the California Water Resources Control Board's once-through cooling policy, the California Water Board's nuclear review committee is overseeing development of an alternative technology assessment for Diablo Canyon. The committee's consultant is expected to submit its final report to the California Water Board in 2014. The California Water Board's policy on once-through cooling and the EPA's final regulations could affect future negotiations between the Central Coast Board and the Utility regarding the status of the 2003 settlement agreement. (See "Item 1. Business−Environmental Matters−Water Quality" above.) PG&E Corporation and the Utility believe that the ultimate outcome of this matter will not have a material impact on their Utility's financial condition or results of operations.

Litigation Related to the San Bruno Accident and Natural Gas Spending

Following the San Bruno accident various lawsuits were filed in San Mateo County Superior Court against PG&E Corporation and the Utility to seek compensation for personal injury and property damage, and other relief, including punitive damages. In 2011 and 2012 , the Utility entered into settlement agreements to resolve many of the claims and In September 2013, the Utility agreed to settle the claims of substantially all of the remaining plaintiffs who sought compensation. At December 31, 2013, the Utility has recorded cumulative charges of $565 million as its best estimate of probable loss for third-party claims related to the San Bruno accident and has made cumulative payments of $520 million to third-party claimants.

At December 31, 2013, there were also four purported shareholder derivative lawsuits outstanding against PG&E Corporation and the Utility seeking recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims. The plaintiffs for three of these lawsuits have filed a consolidated complaint with the San Mateo County Superior Court. The court has lifted the stay on these proceedings for the limited purpose of allowing the parties to exchange information and discuss possible resolution. A case management conference is scheduled for April 18, 2014. The remaining purported shareholder derivative lawsuit, filed in the U.S. District Court for the Northern District of California, remains stayed.   PG&E Corporation and the Utility are uncertain when and how these derivative lawsuits will be resolved.

In addition, on August 23, 2012, a complaint was filed in the San Francisco Superior Court against PG&E Corporation and the Utility (and other unnamed defendants) by individuals who seek certification of a class consisting of all California residents who were customers of the Utility between 1997 and 2010, with certain exceptions. The plaintiffs allege that the Utility collected more than $100 million in customer rates from 1997 through 2010 for the purpose of various safety measures and operations projects but instead used the funds for general corporate purposes such as executive compensation and bonuses. PG&E Corporation and the Utility contest the allegations.

For additional information, see the discussion within MD&A under the heading, “Natural Gas Matters” and in Note 14: Commitments and Contingencies of the Notes to the Consolidated Financial Statements contained in the 2013 Annual Report, which discussions are incorporated herein by reference.

Pending CPUC Investigations

There are three CPUC investigative enforcement proceedings pending against the Utility related to the Utility’s natural gas operations and the San Bruno accident. Evidentiary hearings and briefing on the issue of alleged violations have been completed in each of these investigations. The CPUC has stated that it is prepared to impose significant penalties on the Utility if the CPUC determines that the Utility violated applicable laws, rules, and orders. The SED has recommended that the CPUC impose what the SED characterizes as a penalty of $2.25 billion on the Utility, consisting of a $300 million fine payable to the State General Fund and $1.950 billion of non-recoverable costs to perform work under the Utility’s pipeline safety enhancement plan and to implement the operational remedies. Several other parties have also submitted penalty recommendations. The administrative law judges who oversee the investigation are expected to issue one or more presiding officers’ decisions to address the violations that they have determined the Utility committed and to impose penalties. It is uncertain when the decisions will be issued.

For more information, see discussions within MD&A under the heading, “Natural Gas Matters,” and Note 14: Commitments and Contingencies of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which discussions are incorporated herein by reference.

Other CPUC Enforcement Matters

The Utility and other California gas corporations are required to provide notice to the SED of any self-identified or self-corrected violations of certain state and federal regulations that relate to the safety of natural gas facilities and operating practices. The SED is authorized to issue citations and impose fines for self-identified or self-corrected violations and for violations that the SED identifies through its periodic audits of the Utility's operations or otherwise. In January 2012, the SED imposed fines of $16.8 million on the Utility for self-reported failure to perform certain leak surveys and in 2013 the SED imposed fines ranging from $50,000 to $8.1 million for self-reported violations. The Utility has filed over 50 self-reports with the SED, plus additional follow-up reports, that the SED has not yet addressed. The SED is expected to impose fines or take enforcement action with respect to some of these self-reports.

In August 2013, the CPUC issued two OSCs related to a document submitted by the Utility on July 3, 2013 as "errata" to correct information about some segments in Lines 101 and 147 (two of the Utility's natural gas transmission pipelines that serve the San Francisco peninsula) that had been previously provided to the CPUC in October 2011 to allow the Utility to restore operating pressure on these pipelines. On December 19, 2013, the CPUC issued a decision to impose fines of approximately $14 million on the Utility in connection with the errata submission, finding that the Utility violated CPUC rules that prohibit any person from misleading the CPUC. On January 23, 2014, the Utility filed an application for rehearing of this decision, arguing that it is erroneous in several respects. It is uncertain when the CPUC will issue a decision on the other OSC that directed the Utility to show cause why all orders issued by the CPUC to authorize increased operating pressure on the Utility's gas transmission pipelines should not be immediately suspended pending competent demonstration that the Utility's natural gas system records are reliable.

In addition, the Utility has notified the CPUC and the SED that the Utility is undertaking a system-wide effort to survey its transmission pipelines and identify and remove encroachments from pipeline rights-of-way over a multi-year period. The SED could impose penalties on the Utility or take other enforcement action in connection with this matter.

Criminal Investigation

In June 2011, the U.S. Department of Justice, the California Attorney General's Office, and the San Mateo County District Attorney's Office began an investigation of the San Bruno accident and indicated that the Utility is a target of the investigation. Although the San Mateo County District Attorney's Office has publicly indicated that it will not pursue state criminal charges, the U.S. Department of Justice may still bring criminal charges, including charges based on claims that the Utility violated the federal Pipeline Safety Act, against PG&E Corporation or the Utility. It is uncertain whether any criminal charges will be brought against any of PG&E Corporation's or the Utility's current or former employees. The Utility is continuing to cooperate with federal investigators. A criminal charge or finding would further harm the Utility's reputation. PG&E Corporation and the Utility are unable to estimate the amount or range of reasonably possible losses associated with any civil or criminal penalties that could be imposed and such penalties could have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows. In addition, the Utility's business or operations could be negatively affected by any remedial measures that the Utility may undertake, such as operating its natural gas transmission business subject to the supervision and oversight of an independent monitor.

See the discussions within MD&A under the heading "Natural Gas Matters – Criminal Investigation," and in Note 14: Commitments and Contingencies of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which discussions are incorporated herein by reference.

ITEM 4. Mine Safety Disclosures

Not applicable.

EXECUTIVE OFFICERS OF THE REGISTRANTS

The names, ages and positions of PG&E Corporation "executive officers," as defined by Rule 3b-7 of the General Rules and Regulations under the Exchange Act at February 3, 2014 were as follows.

Name	Age	Position
Anthony F. Earley, Jr.	64	Chairman of the Board, Chief Executive Officer, and President
Kent M. Harvey	55	Senior Vice President and Chief Financial Officer
Christopher P. Johns	53	President, Pacific Gas and Electric Company
Hyun Park	52	Senior Vice President and General Counsel
Greg S. Pruett	56	Senior Vice President, Corporate Affairs
John R. Simon	49	Senior Vice President, Human Resources

All officers of PG&E Corporation serve at the pleasure of the Board of Directors of PG&E Corporation. During at least the past five years through February 3, 2014, the executive officers of PG&E Corporation had the following business experience. Except as otherwise noted, all positions have been held at PG&E Corporation.

Name	Position	Period Held Office
Anthony F. Earley, Jr.	Chairman of the Board, Chief Executive Officer, and President	September 13, 2011 to present
	Executive Chairman of the Board, DTE Energy Company	October 1, 2010 to September 12, 2011
	Chairman of the Board and Chief Executive Officer, DTE Energy Company	August 1998 to September 30, 2010
Kent M. Harvey	Senior Vice President and Chief Financial Officer	August 1, 2009 to present
	Senior Vice President, Financial Services, Pacific Gas and Electric Company	August 1, 2009 to present
	Senior Vice President and Chief Risk and Audit Officer	October 1, 2005 to July 31, 2009
Christopher P. Johns	President, Pacific Gas and Electric Company	August 1, 2009 to present
	Senior Vice President and Chief Financial Officer	May 1, 2009 to July 31, 2009
	Senior Vice President, Financial Services, Pacific Gas and Electric Company	May 1, 2009 to July 31, 2009
	Senior Vice President, Chief Financial Officer, and Treasurer	October 4, 2005 to April 30, 2009
	Senior Vice President and Treasurer, Pacific Gas and Electric Company	June 1, 2007 to April 30, 2009
Hyun Park	Senior Vice President and General Counsel	November 13, 2006 to present
Greg S. Pruett	Senior Vice President, Corporate Affairs	November 1, 2009 to present
	Senior Vice President, Corporate Affairs, Pacific Gas and Electric Company	November 1, 2009 to present
	Senior Vice President, Corporate Relations	November 1, 2007 to October 31, 2009

	Senior Vice President, Corporate Relations, Pacific Gas and Electric Company	March 1, 2009 to October 31, 2009
John R. Simon	Senior Vice President, Human Resources	April 16, 2007 to present
	Senior Vice President, Human Resources, Pacific Gas and Electric Company	April 16, 2007 to present

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The names, ages and positions of the Utility's "executive officers," as defined by Rule 3b-7 of the General Rules and Regulations under the Exchange Act at February 3, 2014 were as follows:

Name	Age	Position
Anthony F. Earley, Jr.	64	Chairman of the Board, Chief Executive Officer, and President, PG&E Corporation
Christopher P. Johns	53	President
Nickolas Stavropoulos	55	Executive Vice President, Gas Operations
Geisha J. Williams	52	Executive Vice President, Electric Operations
Karen A. Austin	52	Senior Vice President and Chief Information Officer
Desmond A. Bell	51	Senior Vice President, Safety and Shared Services
Thomas E. Bottorff	60	Senior Vice President, Regulatory Affairs
Helen A. Burt	57	Senior Vice President and Chief Customer Officer
John T. Conway	56	Senior Vice President, Energy Supply
Edward D. Halpin	52	Senior Vice President and Chief Nuclear Officer
Kent M. Harvey	55	Senior Vice President, Financial Services
Gregory K. Kiraly	49	Senior Vice President, Electric Distribution Operations
Hyun Park	52	Senior Vice President and General Counsel, PG&E Corporation
Greg S. Pruett	56	Senior Vice President, Corporate Affairs
John R. Simon	49	Senior Vice President, Human Resources
Jesus Soto, Jr.	46	Senior Vice President, Engineering, Construction & Operations
Fong Wan	52	Senior Vice President, Energy Procurement
Dinyar B. Mistry	51	V Vice President, Chief Financial Officer, and Controller

All officers of the Utility serve at the pleasure of the Board of Directors of the Utility. During at least the past five years through February 3, 2014, the executive officers of the Utility had the following business experience. Except as otherwise noted, all positions have been held at Pacific Gas and Electric Company.

Name	Position	Period Held Office
Anthony F. Earley, Jr.	Chairman of the Board, Chief Executive Officer, and President, PG&E Corporation	September 13, 2011 to present
	Executive Chairman of the Board, DTE Energy Company	October 1, 2010 to September 12, 2011
	Chairman of the Board and Chief Executive Officer, DTE Energy Company	August 1998 to September 30, 2010
Christopher P. Johns	President	August 1, 2009 to present
	Senior Vice President, Financial Services	May 1, 2009 to July 31, 2009
	Senior Vice President and Chief Financial Officer, PG&E Corporation	May 1, 2009 to July 31, 2009
	Senior Vice President and Treasurer	June 1, 2007 to April 30, 2009

	Senior Vice President, Chief Financial Officer, and Treasurer, PG&E Corporation	October 4, 2005 to April 30, 2009
Nickolas Stavropoulos	Executive Vice President, Gas Operations	June 13, 2011 to present
	Executive Vice President and Chief Operating Officer, U.S. Gas Distribution, National Grid	August 2007 to March 31, 2011
Geisha J. Williams	Executive Vice President, Electric Operations	June 1, 2011 to present
	Senior Vice President, Energy Delivery	December 1, 2007 to May 31, 2011
Karen A. Austin	Senior Vice President and Chief Information Officer	June 1, 2011 to present
	President, Consumer Electronics, Sears Holdings	February 2009 to May 2011
	Executive Vice President, Chief Information Officer, Sears Holdings	March 2005 to January 2009

Desmond A. Bell	Senior Vice President, Safety and Shared Services	January 1, 2012 to present
	Senior Vice President, Shared Services and Chief Procurement Officer	October 1, 2008 to December 31, 2011
	Vice President, Shared Services and Chief Procurement Officer	March 1, 2008 to September 30, 2008
Thomas E. Bottorff	Senior Vice President, Regulatory Affairs	September 1, 2012 to present
	Senior Vice President, Regulatory Relations	October 14, 2005 to August 31, 2012
Helen A. Burt	Senior Vice President and Chief Customer Officer	February 27, 2006 to present
John T. Conway	Senior Vice President, Energy Supply	March 1, 2012 to present
	Senior Vice President, Energy Supply and Chief Nuclear Officer	April 1, 2009 to February 29, 2012
	Senior Vice President, Generation and Chief Nuclear Officer	October 1, 2008 to March 31, 2009
	Senior Vice President and Chief Nuclear Officer	March 1, 2008 to September 30, 2008
Edward D. Halpin	Senior Vice President and Chief Nuclear Officer	April 2, 2012 to present
	President, Chief Executive Officer and Chief Nuclear Officer, South Texas Project Nuclear Operating Company	December 2009 to March 2012
	Chief Nuclear Officer, South Texas Project Nuclear Operating Company	October 2008 to November 2009
Kent M. Harvey	Senior Vice President, Financial Services	August 1, 2009 to present
	Senior Vice President and Chief Financial Officer, PG&E Corporation	August 1, 2009 to present
	Senior Vice President and Chief Risk and Audit Officer, PG&E Corporation	October 1, 2005 to July 31, 2009
Gregory K. Kiraly	Senior Vice President, Electric Distribution Operations	September 18, 2012 to present
	Vice President, Electric Distribution Operations	October 1, 2011 to September 17, 2012
	Vice President, SmartMeter Operations	August 23, 2010 to September 30, 2011
	Vice President, Electric Maintenance and Construction	January 1, 2010 to August 22, 2010
	Vice President, Transmission Substations, Maintenance and Construction	January 1, 2009 to December 31, 2009
Hyun Park	Senior Vice President and General Counsel, PG&E Corporation	November 13, 2006 to present

Greg S. Pruett	Senior Vice President, Corporate Affairs	November 1, 2009 to present
	Senior Vice President, Corporate Affairs, PG&E Corporation	November 1, 2009 to present
	Senior Vice President, Corporate Relations	March 1, 2009 to October 31, 2009
	Senior Vice President, Corporate Relations, PG&E Corporation	November 1, 2007 to October 31, 2009
John R. Simon	Senior Vice President, Human Resources	April 16, 2007 to present
	Senior Vice President, Human Resources, PG&E Corporation	April 16, 2007 to present
Jesus Soto, Jr.	Senior Vice President, Engineering, Construction & Operations	September 2013 to present
	Senior Vice President, Gas Transmission Operations	May 29, 2012 to September 2013
	Vice President, Operations Services, El Paso Pipeline Group	May 2007 to May 2012
Fong Wan	Senior Vice President, Energy Procurement	October 1, 2008 to present
Dinyar B. Mistry	Vice President, Chief Financial Officer, and Controller	October 1, 2011 to present
	Vice President and Controller, PG&E Corporation	March 8, 2010 to present
	Vice President and Controller	March 8, 2010 to September 30, 2011
	Vice President and Chief Risk and Audit Officer	September 16, 2009 to March 7, 2010
	Vice President and Chief Risk and Audit Officer, PG&E Corporation	August 1, 2009 to March 7, 2010
	Vice President, Internal Auditing/Compliance and Ethics, PG&E Corporation	January 1, 2009 to July 31, 2009

PART II

ITEM 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

As of February 3, 2014, there were 64,972 holders of record of PG&E Corporation common stock. PG&E Corporation common stock is listed on the New York Stock Exchange and the Swiss stock exchange. The high and low sales prices of PG&E Corporation common stock for each quarter of the two most recent fiscal years are set forth under the heading "Quarterly Consolidated Financial Data (Unaudited)" in the 2013 Annual Report, which information is incorporated herein by reference. Shares of common stock of the Utility are solely owned by PG&E Corporation. Information about the frequency, amount, and restrictions upon the payment of, dividends on common stock declared by PG&E Corporation and the Utility is set forth in PG&E Corporation's Consolidated Statements of Equity, the Utility's Consolidated Statements of Shareholders' Equity, Note 5: Common Stock and Share-Based Compensation–Dividends of the Notes to the Consolidated Financial Statements, and within MD&A under the heading "Liquidity and Financial Resources—Dividends," in the 2013 Annual Report, which information is incorporated herein by reference.

Sales of Unregistered Equity Securities

During the quarter ended December 31, 2013, PG&E Corporation made equity contributions totaling $305 million to the Utility in order to maintain the Utility's 52% common equity target authorized by the CPUC and to ensure that the Utility has adequate capital to fund its capital expenditures. PG&E Corporation did not make any sales of unregistered equity securities during 2013.

Issuer Purchases of Equity Securities

During the quarter ended December 31, 2013, PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. Also, during the quarter ended December 31, 2013, the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.

ITEM 6. Selected Financial Data

Selected financial information, for each of PG&E Corporation and the Utility for each of the last five fiscal years, is set forth under the heading "Selected Financial Data" in the 2013 Annual Report, which information is incorporated herein by reference.

ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

A discussion of PG&E Corporation's and the Utility's consolidated financial condition and results of operations is set forth under the heading "Management's Discussion and Analysis of Financial Condition and Results of Operations" as well as the "Glossary" in the 2013 Annual Report, which discussion is incorporated herein by reference.

ITEM 7A. Quantitative and Qualitative Disclosures About Market Risk

Information responding to Item 7A is set forth within MD&A under the heading "Risk Management Activities," and in Note 9: Derivatives and Note 10: Fair Value Measurements of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated herein by reference.

ITEM 8. Financial Statements and Supplementary Data

Information responding to Item 8 is set forth under the following headings for PG&E Corporation: “Consolidated Statements of Income,” “Consolidated Statements of Comprehensive Income,” “Consolidated Balance Sheets,” “Consolidated Statements of Cash Flows,” and “Consolidated Statements of Equity;” under the following headings for Pacific Gas and Electric Company: “Consolidated Statements of Income,” “Consolidated Statements of Comprehensive Income,” “Consolidated Balance Sheets,” “Consolidated Statements of Cash Flows,” and “Consolidated Statements of Shareholders' Equity” in the 2013 Annual Report and under the following headings for PG&E Corporation and Pacific Gas and Electric Company jointly: “Notes to the Consolidated Financial Statements,” “Quarterly Consolidated Financial Data (Unaudited),” and “Reports of Independent Registered Public Accounting Firm” in the 2013 Annual Report, which information is incorporated herein by reference.

ITEM 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

Not applicable.

ITEM 9A. Controls and Procedures

Based on an evaluation of PG&E Corporation's and the Utility's disclosure controls and procedures as of December 31, 2013, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures are effective to ensure that information required to be disclosed by PG&E Corporation and the Utility in reports that the companies file or submit under the 1934 Act is recorded, processed, summarized, and reported within the time periods specified in the SEC rules and forms. In addition, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures were effective in ensuring that information required to be disclosed by PG&E Corporation and the Utility in the reports that PG&E Corporation and the Utility file or submit under the 1934 Act is accumulated and communicated to PG&E Corporation’s and the Utility’s management, including PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

There were no changes in internal control over financial reporting that occurred during the quarter ended December 31, 2013 that have materially affected, or are reasonably likely to materially affect, PG&E Corporation's or the Utility's internal control over financial reporting.

Management of PG&E Corporation and the Utility have prepared an annual report on internal control over financial reporting. Management's report, together with the report of the independent registered public accounting firm, appears in the 2013 Annual Report under the heading “Management's Report on Internal Control Over Financial Reporting” and “Report of Independent Registered Public Accounting Firm,” which information is incorporated by reference and included in Exhibit 13 to this report.

ITEM 9B. Other Information

Not applicable.

PART III

ITEM 10. Directors, Executive Officers and Corporate Governance

Information regarding executive officers of PG&E Corporation and the Utility is set forth under "Executive Officers of the Registrants" at the end of Part I of this report. Other information regarding directors is set forth under the heading "Nominees for Directors of PG&E Corporation and Pacific Gas and Electric Company" in the Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders, which information is incorporated herein by reference. Information regarding compliance with Section 16 of the Exchange Act is included under the heading "Section 16(a) Beneficial Ownership Reporting Compliance" in the Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders, which information is incorporated herein by reference.

Website Availability of Code of Ethics, Corporate Governance and Other Documents

The following documents are available both on PG&E Corporation's website www.pgecorp.com, and the Utility's website, www.pge.com: (1) the codes of conduct and ethics adopted by PG&E Corporation and the Utility applicable to their respective directors and employees, including their respective Chief Executive Officers, Chief Financial Officers, Controllers and other executive officers, (2) PG&E Corporation's and the Utility's corporate governance guidelines, and (3) key Board Committee charters, including charters for the companies' Audit Committees and the PG&E Corporation Nominating and Governance Committee and Compensation Committee.

If any amendments are made to, or any waivers are granted with respect to, provisions of the codes of conduct and ethics adopted by PG&E Corporation and the Utility that apply to their respective Chief Executive Officers, Chief Financial Officers, or Controllers, the company whose code is so affected will disclose the nature of such amendment or waiver on its respective website and any waivers to the code will be disclosed in a Current Report on Form 8-K filed within four business days of the waiver.

Procedures for Shareholder Recommendations of Nominees to the Boards of Directors

During 2013 there were no material changes to the procedures described in PG&E Corporation's and the Utility's Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders by which security holders may recommend nominees to PG&E Corporation's or Pacific Gas and Electric Company's Boards of Directors.

Audit Committees and Audit Committee Financial Expert

Information regarding the Audit Committees of PG&E Corporation and the Utility and the "audit committee financial expert" as defined by the SEC is set forth under the headings "Corporate Governance – Board Committee Duties – Audit Committees" and "Corporate Governance – Committee Membership" in the Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders, which information is incorporated herein by reference.

ITEM 11. Executive Compensation

Information responding to Item 11, for each of PG&E Corporation and the Utility, is set forth under the headings "Compensation Discussion and Analysis," "Compensation Committee Report," "Summary Compensation Table - 2013," "Grants of Plan-Based Awards in 2013," "Outstanding Equity Awards at Fiscal Year End - 2013," "Option Exercises and Stock Vested During 2013," "Pension Benefits – 2013," "Non-Qualified Deferred Compensation – 2013," "Potential Payment Upon Resignation, Retirement, Termination, Change in Control, Death, or Disability" and "Compensation of Non-Employee Directors – 2013 Director Compensation" in the Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders, which information is incorporated herein by reference.

ITEM 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information regarding the beneficial ownership of securities for each of PG&E Corporation and the Utility is set forth under the headings "Share Ownership Information – Security Ownership of Management" and "Share Ownership Information – Principal Shareholders" in the Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders, which information is incorporated herein by reference.

Equity Compensation Plan Information

The following table provides information as of December 31, 2013 concerning shares of PG&E Corporation common stock authorized for issuance under PG&E Corporation's existing equity compensation plans.

Plan Category	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights		(b) Weighted Average Exercise Price of Outstanding Options, Warrants and Rights	(c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column(a))	
Equity compensation plans approved by shareholders	6,194,819	(1)	$32.98	3,310,474	(2)
Equity compensation plans not approved by shareholders	-		-	-	
Total equity compensation plans	6,194,819	(1)	$32.98	3,310,474	(2)

(1) Includes 46,185 phantom stock units, 2,329,256 restricted stock units and 3,566,966 performance shares. The weighted average exercise price reported in column (b) does not take these awards into account. For a description of these performance shares, see Note 5: Common Stock and Share-Based Compensation of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which description is incorporated herein by reference. For performance shares, amounts reflected in this table assume payout in shares at 200% of target. The actual number of shares issued can range from 0% to 200% of target depending on achievement of total shareholder return objectives. Also, restricted stock units and performance shares are generally settled in net shares. Upon vesting, shares with a value equal to required tax withholding will be withheld and, in lieu of issuing the shares, taxes will be paid on behalf of employees. Shares not issued due to share withholding or performance achievement below maximum will be available again for issuance.

(2) Represents the total number of shares available for issuance under the LTIP and the 2006 LTIP as of December 31, 2013. Outstanding stock-based awards granted under the LTIP include stock options, and phantom stock. The LTIP expired on December 31, 2005. The 2006 LTIP, which became effective on January 1, 2006, authorizes up to 12 million shares to be issued pursuant to awards granted under the 2006 LTIP. Outstanding stock-based awards granted under the 2006 LTIP include stock options, restricted stock, restricted stock units, phantom stock and performance shares. For a description of the 2006 LTIP, see Note 5: Common Stock and Share-Based Compensation of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which

description is incorporated herein by reference.

ITEM 13. Certain Relationships and Related Transactions, and Director Independence

Information responding to Item 13, for each of PG&E Corporation and the Utility, is included under the headings "Related Party Transactions" and "Corporate Governance – Board and Director Independence and Qualifications" and "Corporate Governance – Committee Membership" in the Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders, which information is incorporated herein by reference.

ITEM 14. Principal Accountant Fees and Services

Information responding to Item 14, for each of PG&E Corporation and the Utility, is set forth under the heading "Information Regarding the Independent Registered Public Accounting Firm for PG&E Corporation and Pacific Gas and Electric Company" in the Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders, which information is incorporated herein by reference.

PART IV

ITEM 15. Exhibits and Financial Statement Schedules

(a) The following documents are filed as a part of this report:

1. The following consolidated financial statements, supplemental information and reports of independent registered public accounting firm are contained in the 2013 Annual Report and are incorporated by reference in this report:

Consolidated Statements of Income for the Years Ended December 31, 2013, 2012, and 2011 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2013, 2012, and 2011 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Balance Sheets at December 31, 2013 and 2012 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Cash Flows for the Years Ended December 31, 2013, 2012, and 2011 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Equity for the Years Ended December 31, 2013, 2012, and 2011 for PG&E Corporation.

Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 2013, 2012, and 2011 for Pacific Gas and Electric Company.

Notes to the Consolidated Financial Statements.

Quarterly Consolidated Financial Data (Unaudited).

Reports of Independent Registered Public Accounting Firm (Deloitte & Touche LLP).

2. The following financial statement schedules and report of independent registered public accounting firm are filed as part of this report:

Reports of Independent Registered Public Accounting Firm (Deloitte & Touche LLP).

I—Condensed Financial Information of Parent as of December 31, 2013 and 2012 and for the Years Ended December 31, 2013, 2012, and 2011.

II—Consolidated Valuation and Qualifying Accounts for each of PG&E Corporation and Pacific Gas and Electric Company for the Years Ended December 31, 2013, 2012, and 2011.

Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto.

3. Exhibits required by Item 601 of Regulation S-K

Exhibit Number	Exhibit Description
2.1	Order of the U.S. Bankruptcy Court for the Northern District of California dated December 22, 2003, Confirming Plan of Reorganization of Pacific Gas and Electric Company, including Plan of Reorganization, dated July 31, 2003 as modified by modifications dated November 6, 2003 and December 19, 2003 (Exhibit B to Confirmation Order and Exhibits B and C to the Plan of Reorganization omitted) (incorporated by reference to Pacific Gas and Electric Company's Registration Statement on Form S-3 No. 333-109994, Exhibit 2.1)
2.2	Order of the U.S. Bankruptcy Court for the Northern District of California dated February 27, 2004 Approving Technical Corrections to Plan of Reorganization of Pacific Gas and Electric Company and Supplementing Confirmation Order to Incorporate such Corrections (incorporated by reference to Pacific Gas and Electric Company's Registration Statement on Form S-3 No. 333-109994, Exhibit 2.2)
3.1	Restated Articles of Incorporation of PG&E Corporation effective as of May 29, 2002 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609), Exhibit 3.1)
3.2	Certificate of Determination for PG&E Corporation Series A Preferred Stock filed December 22, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 3.2)
3.3	Bylaws of PG&E Corporation amended as of June 19, 2013 (incorporated by reference to PG&E Corporation’s Form 10-Q for the quarter ended June 30, 2013 (File No. 1-12609), Exhibit 3.1)
3.4	Restated Articles of Incorporation of Pacific Gas and Electric Company effective as of April 12, 2004 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K filed April 12, 2004 (File No. 1-2348), Exhibit 3)
3.5	Bylaws of Pacific Gas and Electric Company amended as of June 19, 2013 (incorporated by reference to Pacific Gas and Electric Company’s Form 10-Q for the quarter ended June 30, 2013 (File No. 1-2348), Exhibit 3.2)
4.1	Indenture, dated as of April 22, 2005, supplementing, amending and restating the Indenture of Mortgage, dated as of March 11, 2004, as supplemented by a First Supplemental Indenture, dated as of March 23, 2004, and a Second Supplemental Indenture, dated as of April 12, 2004, between Pacific Gas and Electric Company and The Bank of New York Trust Company, N.A. (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 4.1)
4.2	First Supplemental Indenture dated as of March 13, 2007 relating to the Utility’s issuance of $700,000,000 principal amount of 5.80% Senior Notes due March 1, 2037 (incorporated by reference from Pacific Gas and Electric Company’s Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1)
4.3	Second Supplemental Indenture dated as of December 4, 2007 relating to the Utility’s issuance of $500,000,000 principal amount of 5.625% Senior Notes due November 30, 2017 (incorporated by reference from Pacific Gas and Electric Company’s Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1)
4.4	Third Supplemental Indenture dated as of March 3, 2008 relating to the Utility’s issuance of 5.625% Senior Notes due November 30, 2017 and 6.35% Senior Notes due February 15, 2038 (incorporated by reference to Pacific Gas and Electric Company’s Form 8-K dated March 3, 2008 (File No. 1-2348), Exhibit 4.1)
4.5	Fourth Supplemental Indenture dated as of October 21, 2008 relating to the Utility’s issuance of $600,000,000 aggregate principal amount of its 8.25% Senior Notes due

October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated October 21, 2008 (File No. 1-2348), Exhibit 4.1)

4.6 Fifth Supplemental Indenture dated as of November 18, 2008 relating to the Utility's issuance of $400,000,000 aggregate principal amount of its 6.25% Senior Notes due December 1, 2013 and $200 million principal amount of its 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2008 (File No. 1-2348), Exhibit 4.1)

4.7 Sixth Supplemental Indenture, dated as of March 6, 2009 relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 6.25% Senior Notes due March 1, 2039 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 6, 2009 (File No. 1-2348), Exhibit 4.1)

4.8 Eighth Supplemental Indenture dated as of November 18, 2009 relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2009 (File No. 1-2348), Exhibit 4.1)

4.9 Ninth Supplemental Indenture dated as of April 1, 2010 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due January 15, 2040 and $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due March 1, 2037 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 1, 2010 (File No. 1-2348), Exhibit 4.1)

4.10 Tenth Supplemental Indenture dated as of September 15, 2010 relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 15, 2010 (File No. 1-2348), Exhibit 4.1)

4.11 Twelfth Supplemental Indenture dated as of November 18, 2010 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 and $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 5.40% Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2010 (File No. 1-2348), Exhibit 4.1)

4.12 Thirteenth Supplemental Indenture dated as of May 13, 2011, relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.25% Senior Notes due May 15, 2021. (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated May 13, 2011 (File No. 1-2348), Exhibit 4.1)

4.13 Fourteenth Supplemental Indenture dated as of September 12, 2011 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due September 15, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 12, 2011 (File No. 1-2348), Exhibit 4.1)

4.14 Sixteenth Supplemental Indenture dated as of December 1, 2011 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.50% Senior Notes due December 15, 2041 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated December 1, 2011 (File No. 1-2348), Exhibit 4.1)

4.15 Seventeenth Supplemental Indenture dated as of April 16, 2012 relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.45% Senior Notes due April 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 16, 2012 (File No. 1-2348), Exhibit 4.1)

4.16 Eighteenth Supplemental Indenture dated as of August 16, 2012 relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 2.45% Senior Notes due August 15, 2022 and $350,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.75% Senior Notes due August 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 16, 2012 (File No. 1-2348), Exhibit 4.1)

4.17 Nineteenth Supplemental Indenture dated as of June 14, 2013 relating to the issuance of $375,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due June 15, 2023 and $375,000,000 aggregate principal amount of its 4.60% Senior Notes due June 15, 2043 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 14, 2013 (File No. 1-2348), Exhibit 4.1)

4.18 Twentieth Supplemental Indenture dated as of November 12, 2013 relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.85% Senior Notes due November 15, 2023 and $500,000,000 aggregate principal amount of its 5.125% Senior Notes due November 15, 2043 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 12, 2013 (File No. 1-2348), Exhibit 4.1)

4.19 Senior Note Indenture related to PG&E Corporation's 5.75% Senior Notes due April 1, 2014, dated as of March 12, 2009, between PG&E Corporation and Deutsche Bank Trust Company Americas as Trustee (incorporated by reference to PG&E Corporation's Form 8-K dated March 10, 2009 (File No. 1-12609), Exhibit 4.1)

4.20 First Supplemental Indenture, dated as of March 12, 2009 relating to the issuance of $350,000,000 aggregate principal amount of PG&E Corporation's 5.75% Senior Notes due April 1, 2014 (incorporated by reference to PG&E Corporation's Form 8-K dated March 10, 2009 (File No. 1-12609), Exhibit 4.2)

10.1 Amended and restated credit agreement dated April 1, 2013 among (1) PG&E Corporation as borrower, (2) Bank of America, N.A., as administrative agent and a lender, (3) J.P. Morgan Securities LLC, Citigroup Global Markets Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, RBS Securities Inc. and Wells Fargo Securities LLC as joint lead arrangers and joint bookrunners, (4) Citibank N.A. and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, (5) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, and Sumitomo Mitsui Banking Corporation (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-12609), Exhibit 10.1)

10.2 Amended and restated credit agreement dated April 1, 2013 among (1) Pacific Gas and Electric Company as borrower, (2) Citibank N.A., as administrative agent and a lender, (3) Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., J.P. Morgan Securities LLC, RBS Securities Inc. and Wells Fargo Securities LLC as joint lead arrangers and joint bookrunners, (4) Bank of America, N.A. and JPMorgan Chase Bank, N.A. as co-syndication agents and lenders, (5) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, and Sumitomo Mitsui Banking Corporation (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-2348), Exhibit 10.2)

10.3 Settlement Agreement among California Public Utilities Commission, Pacific Gas and Electric Company and PG&E Corporation, dated as of December 19, 2003, together with appendices (incorporated by reference to PG&E Corporation's and Pacific Gas and

	Electric Company's Form 8-K filed December 22, 2003 (File No. 1-12609 and File No. 1-2348), Exhibit 99)
10.4	Transmission Control Agreement among the California Independent System Operator (CAISO) and the Participating Transmission Owners, including Pacific Gas and Electric Company, effective as of March 31, 1998, as amended (CAISO, FERC Electric Tariff No. 7) (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.8)

10.5	Operating Agreement, as amended on November 12, 2004, effective as of December 22, 2004, between the State of California Department of Water Resources and Pacific Gas and Electric Company (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.9)
10.6*	Letter regarding Compensation Agreement between PG&E Corporation and Anthony F. Earley, Jr. dated August 8, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.1)
10.7*	Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2013 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.5)
10.8*	Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2012 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.3)
10.9*	Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011(incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.2)
10.10 *	Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.3)
10.11 *	Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2013 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.6)
10.12 *	Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2012 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.4)
10.13 *	Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.4)
10.14 *	Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.5)
10.15 *	Restricted Stock Unit Agreement between Christopher P. Johns and PG&E Corporation dated May 9, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12609), Exhibit 10.4)
10.16 *	Letter regarding Compensation Arrangement between PG&E Corporation and Hyun Park dated October 10, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2006 (File No. 1-12609), Exhibit 10.18)
10.17 *	Letter regarding Compensation Arrangement between PG&E Corporation and John R. Simon dated March 9, 2007 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.18)
10.18 *	

Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Jesus Soto, Jr. dated April 4, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2012 (File No. 1-2348), Exhibit 10.2)

10.19*	Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Edward D. Halpin dated February 3, 2012 for employment starting April 1, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2012 (File No. 1-2348), Exhibit 10.21)
10.20*	Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Karen Austin dated April 29, 2011 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-2348), Exhibit 10.7)
10.21*	Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Nick Stavropoulos dated April 29, 2011 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-2348), Exhibit 10.8)
10.22*	PG&E Corporation Supplemental Retirement Savings Plan amended effective as of September 19, 2001, and frozen after December 31, 2004 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004) (File No. 1-12609), Exhibit 10.10)
10.23*	PG&E Corporation 2005 Supplemental Retirement Savings Plan, as amended effective September 17, 2013 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2013 (File No. 1-12609), Exhibit 10.1)
10.24*	PG&E Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, effective as of January 1, 2005 (as amended to comply with Internal Revenue Code Section 409A regulations effective as of January 1, 2009) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.24)
10.25*	PG&E Corporation Deferred Compensation Plan for Non-Employee Directors, as amended and restated effective as of July 22, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 1998 (File No. 1-12609), Exhibit 10.2)
10.26*	Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.27)
10.27*	Amendment to PG&E Corporation Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.27)
10.28 *	Amendment to Pacific Gas and Electric Company Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2008 (File No. 1-2348), Exhibit 10.28)
10.29 *	PG&E Corporation Supplemental Executive Retirement Plan, as amended effective as of January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609, Exhibit 10.31)
10.30 *	PG&E Corporation Defined Contribution Executive Supplemental Retirement Plan, as amended effective September 17, 2013 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2013 (File No. 1-12609), Exhibit 10.2)

10.31*	Pacific Gas and Electric Company Relocation Assistance Program for Officers (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2008 (File No. 1-2348), Exhibit 10.30)
10.32*	Postretirement Life Insurance Plan of the Pacific Gas and Electric Company as amended and restated on February 14, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-2348), Exhibit 10.7)

10.33*	PG&E Corporation Non-Employee Director Stock Incentive Plan (a component of the PG&E Corporation Long-Term Incentive Program) as amended effective as of July 1, 2004 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.27)
10.34*	Resolution of the PG&E Corporation Board of Directors dated September 19, 2012, adopting director compensation arrangement effective January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012) (File No. 1-12609), Exhibit 10.36)
10.35*	Resolution of the Pacific Gas and Electric Company Board of Directors dated September 19, 2012, adopting director compensation arrangement effective January 1, 2013 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2012) (File No. 1-12609), Exhibit 10.37)
10.36*	PG&E Corporation 2006 Long-Term Incentive Plan, as amended effective January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.40)
10.37*	PG&E Corporation Long-Term Incentive Program (including the PG&E Corporation Stock Option Plan and Performance Unit Plan), as amended May 16, 2001, (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2001 (File No. 1-12609), Exhibit 10)
10.38*	Form of Restricted Stock Unit Agreement for 2013 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.3)
10.39*	Form of Restricted Stock Unit Agreement for 2012 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.1)
10.40*	Form of Restricted Stock Unit Agreement for 2011 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2011 (File No. 1-12609), Exhibit 10.1)
10.41*	Form of Restricted Stock Unit Agreement for 2010 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2010 (File No. 1-12609), Exhibit 10.2)
10.42 *	Form of Restricted Stock Unit Agreement for 2009 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2009 (File No. 1-12609), Exhibit 10.2)
10.43 *	Form of Restricted Stock Unit Agreement for 2013 grants to directors under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-12609), Exhibit 10.1)
10.44 *	Form of Restricted Stock Unit Agreement for 2012 grants to directors under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2012 (File No. 1-12609), Exhibit 10.3)
10.45 *	Form of Non-Qualified Stock Option Agreement under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 6, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 99.1)
10.46 *	Form of Performance Share Agreement for 2013 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's

Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.4)

10.47*	Form of Performance Share Agreement for 2012 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.2)
10.48*	Form of Performance Share Agreement for 2011 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2011 (File No. 1-12609), Exhibit 10.2)
10.49*	Form of Performance Share Agreement for 2010 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2010 (File No. 1-12609), Exhibit 10.3)
10.50*	PG&E Corporation 2010 Executive Stock Ownership Guidelines as adopted September 14, 2010, effective January 1, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.3)
10.51*	PG&E Corporation Executive Stock Ownership Program Guidelines as amended effective September 15, 2010 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.2)
10.52*	PG&E Corporation 2012 Officer Severance Policy, effective as of March 1, 2012 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.6)
10.53*	PG&E Corporation Officer Severance Policy, as amended effective as of March 1, 2012 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.5)
10.54*	PG&E Corporation Officer Severance Policy, as amended effective as of February 15, 2011 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2010 (File No. 1-12609), Exhibit 10.51)
10.55*	PG&E Corporation Golden Parachute Restriction Policy effective as of February 15, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005 (File No. 1-12609), Exhibit 10.49)
10.56 *	Amendment to PG&E Corporation Golden Parachute Restriction Policy dated December 31, 2008 (amendment to comply with Internal Revenue Code Section 409A Regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.58)
10.57 *	PG&E Corporation Director Grantor Trust Agreement dated April 1, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 1998 (File No. 1-12609), Exhibit 10.1)
10.58 *	PG&E Corporation Officer Grantor Trust Agreement dated April 1, 1998, as updated effective January 1, 2005 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.39)
10.59 *	PG&E Corporation and Pacific Gas and Electric Company Executive Incentive Compensation Recoupment Policy effective as of February 17, 2010 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2009 (File No. 1-12609), Exhibit 10.54)
10.60 *	Resolution of the Board of Directors of PG&E Corporation regarding indemnification of officers and directors dated December 18, 1996 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.40)
10.61 *	Resolution of the Board of Directors of Pacific Gas and Electric Company regarding indemnification of officers and directors dated July 19, 1995 (incorporated by reference to Pacific Gas and Electric Company’s Form 10-K for the year ended December 31, 2004 (File No. 1-2348), Exhibit 10.41)

12.1	Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company

12.2	Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company
12.3	Computation of Ratios of Earnings to Fixed Charges for PG&E Corporation
13	The following portions of the 2013 Annual Report to Shareholders of PG&E Corporation and Pacific Gas and Electric Company are included: “Selected Financial Data,” “Glossary,” “Management's Discussion and Analysis of Financial Condition and Results of Operations,” financial statements of PG&E Corporation entitled “Consolidated Statements of Income,” “Consolidated Statements of Comprehensive Income,” “Consolidated Balance Sheets,” “Consolidated Statements of Cash Flows,” and “Consolidated Statements of Equity,” financial statements of Pacific Gas and Electric Company entitled “Consolidated Statements of Income,” “Consolidated Statements of Comprehensive Income,” “Consolidated Balance Sheets,” “Consolidated Statements of Cash Flows,” and “Consolidated Statements of Shareholders' Equity,” “Notes to the Consolidated Financial Statements,” “Quarterly Consolidated Financial Data (Unaudited),” “Management's Report on Internal Control Over Financial Reporting,” and “Report of Independent Registered Public Accounting Firm.”
21	Subsidiaries of the Registrant
23	Consent of Independent Registered Public Accounting Firm (Deloitte & Touche LLP)
24	Powers of Attorney
31.1	Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002
32.1**	Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

* Management contract or compensatory agreement.
** Pursuant to Item 601(b)(32) of SEC Regulation S-K, these exhibits are furnished rather than filed with this report.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrants have duly caused this Annual Report on Form 10-K for the year ended December 31, 2013 to be signed on their behalf by the undersigned, thereunto duly authorized.

PG&E CORPORATION (Registrant)	PACIFIC GAS AND ELECTRIC COMPANY (Registrant)
ANTHONY F. EARLEY, JR. Anthony F. Earley, Jr.	CHRISTOPHER P. JOHNS Christopher P. Johns
By: Chairman of the Board, Chief Executive Officer, and President	By: President
Date: February 11, 2014	Date: February 11, 2014

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrants and in the capacities and on the dates indicated.

Signature	Title	Date
A. Principal Executive Officers		
ANTHONY F. EARLEY, JR. Anthony F. Earley, Jr.	Chairman of the Board, Chief Executive Officer, and President (PG&E Corporation)	February 11, 2014
CHRISTOPHER P. JOHNS Christopher P. Johns	President (Pacific Gas and Electric Company)	February 11, 2014
B. Principal Financial Officers		
KENT M. HARVEY Kent M. Harvey	Senior Vice President and Chief Financial Officer (PG&E Corporation)	February 11, 2014
DINYAR B. MISTRY Dinyar B. Mistry	Vice President, Chief Financial Officer, and Controller (Pacific Gas and Electric Company)	February 11, 2014
C. Principal Accounting Officer		
DINYAR B. MISTRY Dinyar B. Mistry	Vice President and Controller (PG&E Corporation) Vice President, Chief Financial Officer, and Controller (Pacific Gas and Electric Company)	February 11, 2014

D. Directors

*LEWIS CHEW Lewis Chew	Director	February 11, 2014

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*C. LEE COX C. Lee Cox	Director	February 11, 2014
*ANTHONY F. EARLEY, JR. Anthony F. Earley, Jr.	Director	February 11, 2014
*FRED J. FOWLER Fred J. Fowler	Director	February 11, 2014
*MARYELLEN C. HERRINGER Maryellen C. Herringer	Director	February 11, 2014
*CHRISTOPHER P. JOHNS Christopher P. Johns	Director (Pacific Gas and Electric Company only)	February 11, 2014
*RICHARD C. KELLY	Director	February 11, 2014
*ROGER H. KIMMEL Roger H. Kimmel	Director	February 11, 2014
*RICHARD A. MESERVE Richard A. Meserve	Director	February 11, 2014
*FORREST E. MILLER Forrest E. Miller	Director	February 11, 2014
*ROSENDO G. PARRA Rosendo G. Parra	Director	February 11, 2014
*BARBARA L. RAMBO Barbara L. Rambo	Director	February 11, 2014
*BARRY LAWSON WILLIAMS Barry Lawson Williams	Director	February 11, 2014

*By: HYUN PARK
HYUN PARK, Attorney-in-Fact

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
PG&E Corporation and Pacific Gas and Electric Company
San Francisco, California

We have audited the consolidated financial statements of PG&E Corporation and subsidiaries (the “Company”) and Pacific Gas and Electric Company and subsidiaries (the “Utility”) as of December 31, 2013 and 2012, and for each of the three years in the period ended December 31, 2013, and the Company's and the Utility’s internal control over financial reporting as of December 31, 2013, and have issued our reports thereon dated February 11, 2014 (which report on the consolidated financial statements expresses an unqualified opinion and includes an explanatory paragraph relating to three investigative enforcement proceedings pending with the California Public Utilities Commission that may result in material amounts of penalties); such consolidated financial statements and reports are included in your 2013 Annual Report to Shareholders of the Company and the Utility and are incorporated herein by reference. Our audits also included the consolidated financial statement schedules of the Company and Utility listed in Item 15. These consolidated financial statement schedules are the responsibility of the Company's and the Utility’s management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California
February 11, 2014

PG&E CORPORATION
SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF PARENT
CONDENSED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(in millions, except per share amounts)

	Year Ended December 31,		
	2013	2012	2011
Administrative service revenue	$41	$43	$44
Operating expenses	(42)	(41)	(44)
Interest income	1	1	1
Interest expense	(25)	(22)	(22)
Other income	(57)	(39)	(17)
Equity in earnings of subsidiaries	848	817	852
Income before income taxes	766	759	814
Income tax benefit	48	57	30
Net income	$814	$816	$844
Other Comprehensive Income			
Pension and other postretirement benefit plans (net of taxes of $80, $72, $9, at respective dates)	113	108	(11)
Other (net of taxes of $26, $3, and $0, at respective dates)	38	4	-
Total other comprehensive income (loss)	151	112	(11)
Comprehensive Income	$965	$928	$833
Weighted average common shares outstanding, basic	444	424	401
Weighted average common shares outstanding, diluted	445	425	402
Net earnings per common share, basic	$1.83	$1.92	$2.10
Net earnings per common share, diluted	$1.83	$1.92	$2.10

PG&E CORPORATION
SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF PARENT – (Continued)
CONDENSED BALANCE SHEETS
(in millions)

	Balance at December 31, 2013	2012
ASSETS		
Current Assets		
Cash and cash equivalents	$231	$207
Advances to affiliates	30	26
Income taxes receivable	13	33
Other current assets	86	-
Total current assets	360	266
Noncurrent Assets		
Equipment	2	1
Accumulated depreciation	(1)	(1)
Net equipment	1	-
Investments in subsidiaries	14,711	13,387
Other investments	110	102
Income taxes receivable	5	5
Deferred income taxes	188	178
Other	-	1
Total noncurrent assets	15,015	13,673
Total Assets	$15,375	$13,939
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$260	$120
Long-term debt, classified as current	350	-
Accounts payable – other	66	48
Other	230	221
Total current liabilities	906	389
Noncurrent Liabilities		
Long-term debt	-	349
Other	127	127
Total noncurrent liabilities	127	476
Common Shareholders' Equity		
Common stock	9,550	8,428
Reinvested earnings	4,742	4,747
Accumulated other comprehensive income (loss)	50	(101)
Total common shareholders' equity	14,342	13,074
Total Liabilities and Shareholders' Equity	$15,375	$13,939

PG&E CORPORATION
SCHEDULE I – CONDENSED FINANCIAL INFORMATION OF PARENT – (Continued)
CONDENSED STATEMENTS OF CASH FLOWS
(in millions)

	Year Ended December 31,		
	2013	2012	2011
Cash Flows from Operating Activities:			
Net income	$814	$816	$844
Adjustments to reconcile net income to net cash provided by operating activities:			
Stock-based compensation amortization	54	51	36
Equity in earnings of subsidiaries	(848)	(817)	(852)
Deferred income taxes and tax credits, net	(10)	(31)	(26)
Noncurrent income taxes receivable/payable	-	(6)	(47)
Current income taxes receivable/payable	20	(82)	49
Other	(20)	20	(80)
Net cash provided by (used in) operating activities	10	(49)	(76)
Cash Flows From Investing Activities:			
Investment in subsidiaries	(1,371)	(1,023)	(759)
Dividends received from subsidiaries (1)	716	716	716
Proceeds from tax equity investments	275	228	129
Other	(8)	-	-
Net cash provided by (used in) investing activities	(388)	(79)	86
Cash Flows From Financing Activities:			
Borrowings under revolving credit facilities	140	120	150
Repayments under revolving credit facilities	-	-	(150)
Common stock issued	1,045	751	662
Common stock dividends paid (2)	(782)	(746)	(704)
Other	(1)	1	1
Net cash provided by (used in) financing activities	402	126	(41)
Net change in cash and cash equivalents	24	(2)	(31)
Cash and cash equivalents at January 1	207	209	240
Cash and cash equivalents at December 31	$231	$207	$209
Supplemental disclosures of cash flow information			
Cash received (paid) for:			
Interest, net of amounts capitalized	$(23)	$(20)	$(20)
Income taxes, net	21	(60)	8
Supplemental disclosures of noncash investing and financing activities			
Noncash common stock issuances	$22	$22	$24
Common stock dividends declared but not yet paid	208	196	188

(1) Because of its nature as a holding company, PG&E Corporation classifies dividends received from subsidiaries an investing cash flow.

(2) On January 15, April 15, July 15, October 15, 2013, PG&E Corporation paid quarterly common stock dividends of $0.455 per share.

On January 15, April 15, July 15, October 15, 2012, PG&E Corporation paid quarterly common stock dividends of $0.455 per share.

On January 15, April 15, July 15, October 15, 2011, PG&E Corporation paid quarterly common stock dividends of $0.455 per share.

PG&E Corporation

SCHEDULE II – CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2013, 2012, and 2011
(in millions)

		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions (2)	Balance at End of Period
Valuation and qualifying accounts deducted from assets:					
2013:					
Allowance for uncollectible accounts(1)	$87	$53	$-	$60	$80
2012:					
Allowance for uncollectible accounts(1)	$81	$66	$-	$60	$87
2011:					
Allowance for uncollectible accounts(1)	$81	$60	$-	$60	$81

(1) Allowance for uncollectible accounts is deducted from “Accounts receivable – Customers.”

(2) Deductions consist principally of write-offs, net of collections of receivables previously written off.

Pacific Gas and Electric Company

SCHEDULE II – CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2013, 2012, and 2011
(in millions)

		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions (2)	Balance at End of Period
Valuation and qualifying accounts deducted from assets:					
2013:					
Allowance for uncollectible accounts(1)	$87	$53	$-	$60	$80
2012:					
Allowance for uncollectible accounts(1)	$81	$66	$-	$60	$87
2011:					
Allowance for uncollectible accounts(1)	$81	$60	$-	$60	$81

(1) Allowance for uncollectible accounts is deducted from “Accounts receivable – Customers.”

(2) Deductions consist principally of write-offs, net of collections of receivables previously written off.

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EXHIBIT INDEX

Exhibit Number	Exhibit Description
2.1	Order of the U.S. Bankruptcy Court for the Northern District of California dated December 22, 2003, Confirming Plan of Reorganization of Pacific Gas and Electric Company, including Plan of Reorganization, dated July 31, 2003 as modified by modifications dated November 6, 2003 and December 19, 2003 (Exhibit B to Confirmation Order and Exhibits B and C to the Plan of Reorganization omitted) (incorporated by reference to Pacific Gas and Electric Company's Registration Statement on Form S-3 No. 333-109994, Exhibit 2.1)
2.2	Order of the U.S. Bankruptcy Court for the Northern District of California dated February 27, 2004 Approving Technical Corrections to Plan of Reorganization of Pacific Gas and Electric Company and Supplementing Confirmation Order to Incorporate such Corrections (incorporated by reference to Pacific Gas and Electric Company's Registration Statement on Form S-3 No. 333-109994, Exhibit 2.2)
3.1	Restated Articles of Incorporation of PG&E Corporation effective as of May 29, 2002 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609), Exhibit 3.1)
3.2	Certificate of Determination for PG&E Corporation Series A Preferred Stock filed December 22, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 3.2)
3.3	Bylaws of PG&E Corporation amended as of June 19, 2013 (incorporated by reference to PG&E Corporation’s Form 10-Q for the quarter ended June 30, 2013 (File No. 1-12609), Exhibit 3.1)
3.4	Restated Articles of Incorporation of Pacific Gas and Electric Company effective as of April 12, 2004 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K filed April 12, 2004 (File No. 1-2348), Exhibit 3)
3.5	Bylaws of Pacific Gas and Electric Company amended as of June 19, 2013 (incorporated by reference to Pacific Gas and Electric Company’s Form 10-Q for the quarter ended June 30, 2013 (File No. 1-2348), Exhibit 3.2)
4.1	Indenture, dated as of April 22, 2005, supplementing, amending and restating the Indenture of Mortgage, dated as of March 11, 2004, as supplemented by a First Supplemental Indenture, dated as of March 23, 2004, and a Second Supplemental Indenture, dated as of April 12, 2004, between Pacific Gas and Electric Company and The Bank of New York Trust Company, N.A. (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 4.1)
4.2	First Supplemental Indenture dated as of March 13, 2007 relating to the Utility’s issuance of $700,000,000 principal amount of 5.80% Senior Notes due March 1, 2037 (incorporated by reference from Pacific Gas and Electric Company’s Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1)
4.3	Second Supplemental Indenture dated as of December 4, 2007 relating to the Utility’s issuance of $500,000,000 principal amount of 5.625% Senior Notes due November 30, 2017 (incorporated by reference from Pacific Gas and Electric Company’s Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1)
4.4	Third Supplemental Indenture dated as of March 3, 2008 relating to the Utility’s issuance of 5.625% Senior Notes due November 30, 2017 and 6.35% Senior Notes due

	February 15, 2038 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 3, 2008 (File No. 1-2348), Exhibit 4.1)
4.5	Fourth Supplemental Indenture dated as of October 21, 2008 relating to the Utility's issuance of $600,000,000 aggregate principal amount of its 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated October 21, 2008 (File No. 1-2348), Exhibit 4.1)

4.6 Fifth Supplemental Indenture dated as of November 18, 2008 relating to the Utility's issuance of $400,000,000 aggregate principal amount of its 6.25% Senior Notes due December 1, 2013 and $200 million principal amount of its 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2008 (File No. 1-2348), Exhibit 4.1)
4.7 Sixth Supplemental Indenture, dated as of March 6, 2009 relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 6.25% Senior Notes due March 1, 2039 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 6, 2009 (File No. 1-2348), Exhibit 4.1)
4.8 Eighth Supplemental Indenture dated as of November 18, 2009 relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2009 (File No. 1-2348), Exhibit 4.1)
4.9 Ninth Supplemental Indenture dated as of April 1, 2010 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due January 15, 2040 and $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due March 1, 2037 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 1, 2010 (File No. 1-2348), Exhibit 4.1)
4.10 Tenth Supplemental Indenture dated as of September 15, 2010 relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 15, 2010 (File No. 1-2348), Exhibit 4.1)
4.11 Twelfth Supplemental Indenture dated as of November 18, 2010 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 and $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 5.40% Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2010 (File No. 1-2348), Exhibit 4.1)
4.12 Thirteenth Supplemental Indenture dated as of May 13, 2011, relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.25% Senior Notes due May 15, 2021. (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated May 13, 2011 (File No. 1-2348), Exhibit 4.1)
4.13 Fourteenth Supplemental Indenture dated as of September 12, 2011 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due September 15, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 12, 2011 (File No. 1-2348), Exhibit 4.1)
4.14 Sixteenth Supplemental Indenture dated as of December 1, 2011 relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.50% Senior Notes due December 15, 2041 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated December 1, 2011 (File No. 1-2348), Exhibit 4.1)
4.15 Seventeenth Supplemental Indenture dated as of April 16, 2012 relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.45% Senior Notes due April 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 16, 2012 (File No. 1-2348), Exhibit 4.1)
4.16 Eighteenth Supplemental Indenture dated as of August 16, 2012 relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's

2.45% Senior Notes due August 15, 2022 and $350,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.75% Senior Notes due August 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 16, 2012 (File No. 1-2348), Exhibit 4.1)

4.17 Nineteenth Supplemental Indenture dated as of June 14, 2013 relating to the issuance of $375,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due June 15, 2023 and $375,000,000 aggregate principal amount of its 4.60% Senior Notes due June 15, 2043 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 14, 2013 (File No. 1-2348), Exhibit 4.1)

4.18 Twentieth Supplemental Indenture dated as of November 12, 2013 relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.85% Senior Notes due November 15, 2023 and $500,000,000 aggregate principal amount of its 5.125% Senior Notes due November 15, 2043 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 12, 2013 (File No. 1-2348), Exhibit 4.1)

4.19 Senior Note Indenture related to PG&E Corporation's 5.75% Senior Notes due April 1, 2014, dated as of March 12, 2009, between PG&E Corporation and Deutsche Bank Trust Company Americas as Trustee (incorporated by reference to PG&E Corporation's Form 8-K dated March 10, 2009 (File No. 1-12609), Exhibit 4.1)

4.20 First Supplemental Indenture, dated as of March 12, 2009 relating to the issuance of $350,000,000 aggregate principal amount of PG&E Corporation's 5.75% Senior Notes due April 1, 2014 (incorporated by reference to PG&E Corporation's Form 8-K dated March 10, 2009 (File No. 1-12609), Exhibit 4.2)

10.1 Amended and restated credit agreement dated April 1, 2013 among (1) PG&E Corporation as borrower, (2) Bank of America, N.A., as administrative agent and a lender, (3) J.P. Morgan Securities LLC, Citigroup Global Markets Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, RBS Securities Inc. and Wells Fargo Securities LLC as joint lead arrangers and joint bookrunners, (4) Citibank N.A. and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, (5) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, and Sumitomo Mitsui Banking Corporation (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-12609), Exhibit 10.1)

10.2 Amended and restated credit agreement dated April 1, 2013 among (1) Pacific Gas and Electric Company as borrower, (2) Citibank N.A., as administrative agent and a lender, (3) Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., J.P. Morgan Securities LLC, RBS Securities Inc. and Wells Fargo Securities LLC as joint lead arrangers and joint bookrunners, (4) Bank of America, N.A. and JPMorgan Chase Bank, N.A. as co-syndication agents and lenders, (5) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, and Sumitomo Mitsui Banking Corporation (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-2348), Exhibit 10.2)

10.3 Settlement Agreement among California Public Utilities Commission, Pacific Gas and Electric Company and PG&E Corporation, dated as of December 19, 2003, together

	with appendices (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 8-K filed December 22, 2003 (File No. 1-12609 and File No. 1-2348), Exhibit 99)
10.4	Transmission Control Agreement among the California Independent System Operator (CAISO) and the Participating Transmission Owners, including Pacific Gas and Electric Company, effective as of March 31, 1998, as amended (CAISO, FERC Electric Tariff No. 7) (incorporated by reference to PG&E Corporation’s and Pacific Gas and Electric Company’s Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.8)

10.5		Operating Agreement, as amended on November 12, 2004, effective as of December 22, 2004, between the State of California Department of Water Resources and Pacific Gas and Electric Company (incorporated by reference to PG&E Corporation’s and Pacific Gas and Electric Company’s Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.9)
10.6	*	Letter regarding Compensation Agreement between PG&E Corporation and Anthony F. Earley, Jr. dated August 8, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.1)
10.7	*	Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2013 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.5)
10.8	*	Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2012 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.3)
10.9	*	Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011(incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.2)
10.10	*	Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.3)
10.11	*	Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2013 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.6)
10.12	*	Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2012 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.4)
10.13	*	Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.4)
10.14	*	Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.5)
10.15	*	Restricted Stock Unit Agreement between Christopher P. Johns and PG&E Corporation dated May 9, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12609), Exhibit 10.4)
10.16	*	Letter regarding Compensation Arrangement between PG&E Corporation and Hyun Park dated October 10, 2006 (incorporated by reference to PG&E Corporation’s Form 10-K for the year ended December 31, 2006 (File No. 1-12609), Exhibit 10.18)
10.17	*	Letter regarding Compensation Arrangement between PG&E Corporation and John R. Simon dated March 9, 2007 (incorporated by reference to PG&E Corporation’s Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.18)
10.18	*	Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Jesus Soto, Jr. dated April 4, 2012 (incorporated by reference to Pacific Gas and

Electric Company's Form 10-Q for the quarter ended June 30, 2012 (File No. 1-2348), Exhibit 10.2)

10.19*	Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Edward D. Halpin dated February 3, 2012 for employment starting April 1, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2012 (File No. 1-2348), Exhibit 10.21)
10.20 *	Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Karen Austin dated April 29, 2011 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-2348), Exhibit 10.7)
10.21 *	Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Nick Stavropoulos dated April 29, 2011 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-2348), Exhibit 10.8)
10.22 *	PG&E Corporation Supplemental Retirement Savings Plan amended effective as of September 19, 2001, and frozen after December 31, 2004 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004) (File No. 1-12609), Exhibit 10.10)
10.23 *	PG&E Corporation 2005 Supplemental Retirement Savings Plan, as amended effective September 17, 2013 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2013 (File No. 1-12609), Exhibit 10.1)
10.24 *	PG&E Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, effective as of January 1, 2005 (as amended to comply with Internal Revenue Code Section 409A regulations effective as of January 1, 2009) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.24)
10.25 *	PG&E Corporation Deferred Compensation Plan for Non-Employee Directors, as amended and restated effective as of July 22, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 1998 (File No. 1-12609), Exhibit 10.2)
10.26 *	Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.27)
10.27 *	Amendment to PG&E Corporation Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.27)
10.28 *	Amendment to Pacific Gas and Electric Company Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2008 (File No. 1-2348), Exhibit 10.28)
10.29 *	PG&E Corporation Supplemental Executive Retirement Plan, as amended effective as of January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609, Exhibit 10.31)
10.30 *	PG&E Corporation Defined Contribution Executive Supplemental Retirement Plan, as amended effective September 17, 2013 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2013 (File No. 1-12609), Exhibit 10.2)
10.31 *	Pacific Gas and Electric Company Relocation Assistance Program for Officers (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the

	year ended December 31, 2008 (File No. 1-2348), Exhibit 10.30)
10.32 *	Postretirement Life Insurance Plan of the Pacific Gas and Electric Company as amended and restated on February 14, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-2348), Exhibit 10.7)

10.33 * PG&E Corporation Non-Employee Director Stock Incentive Plan (a component of the PG&E Corporation Long-Term Incentive Program) as amended effective as of July 1, 2004 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.27)

10.34 * Resolution of the PG&E Corporation Board of Directors dated September 19, 2012, adopting director compensation arrangement effective January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012) (File No. 1-12609), Exhibit 10.36)

10.35* Resolution of the Pacific Gas and Electric Company Board of Directors dated September 19, 2012, adopting director compensation arrangement effective January 1, 2013 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2012) (File No. 1-12609), Exhibit 10.37)

10.36 * PG&E Corporation 2006 Long-Term Incentive Plan, as amended effective January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.40)

10.37* PG&E Corporation Long-Term Incentive Program (including the PG&E Corporation Stock Option Plan and Performance Unit Plan), as amended May 16, 2001, (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2001 (File No. 1-12609), Exhibit 10)

10.38* Form of Restricted Stock Unit Agreement for 2013 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.3)

10.39* Form of Restricted Stock Unit Agreement for 2012 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.1)

10.40* Form of Restricted Stock Unit Agreement for 2011 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2011 (File No. 1-12609), Exhibit 10.1)

10.41 * Form of Restricted Stock Unit Agreement for 2010 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2010 (File No. 1-12609), Exhibit 10.2)

10.42 * Form of Restricted Stock Unit Agreement for 2009 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2009 (File No. 1-12609), Exhibit 10.2)

10.43 * Form of Restricted Stock Unit Agreement for 2013 grants to directors under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-12609), Exhibit 10.1)

10.44 * Form of Restricted Stock Unit Agreement for 2012 grants to directors under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2012 (File No. 1-12609), Exhibit 10.3)

10.45 * Form of Non-Qualified Stock Option Agreement under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 6, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 99.1)

10.46 * Form of Performance Share Agreement for 2013 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's

Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.4)

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10.47*	Form of Performance Share Agreement for 2012 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.2)
10.48*	Form of Performance Share Agreement for 2011 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2011 (File No. 1-12609), Exhibit 10.2)
10.49*	Form of Performance Share Agreement for 2010 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2010 (File No. 1-12609), Exhibit 10.3)
10.50*	PG&E Corporation 2010 Executive Stock Ownership Guidelines as adopted September 14, 2010, effective January 1, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.3)
10.51*	PG&E Corporation Executive Stock Ownership Program Guidelines as amended effective September 15, 2010 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.2)
10.52*	PG&E Corporation 2012 Officer Severance Policy, effective as of March 1, 2012 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.6)
10.53*	PG&E Corporation Officer Severance Policy, as amended effective as of March 1, 2012 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.5)
10.54*	PG&E Corporation Officer Severance Policy, as amended effective as of February 15, 2011 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2010 (File No. 1-12609), Exhibit 10.51)
10.55*	PG&E Corporation Golden Parachute Restriction Policy effective as of February 15, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005 (File No. 1-12609), Exhibit 10.49)
10.56 *	Amendment to PG&E Corporation Golden Parachute Restriction Policy dated December 31, 2008 (amendment to comply with Internal Revenue Code Section 409A Regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.58)
10.57 *	PG&E Corporation Director Grantor Trust Agreement dated April 1, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 1998 (File No. 1-12609), Exhibit 10.1)
10.58 *	PG&E Corporation Officer Grantor Trust Agreement dated April 1, 1998, as updated effective January 1, 2005 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.39)
10.59 *	PG&E Corporation and Pacific Gas and Electric Company Executive Incentive Compensation Recoupment Policy effective as of February 17, 2010 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2009 (File No. 1-12609), Exhibit 10.54)
10.60 *	Resolution of the Board of Directors of PG&E Corporation regarding indemnification of officers and directors dated December 18, 1996 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.40)
10.61 *	Resolution of the Board of Directors of Pacific Gas and Electric Company regarding indemnification of officers and directors dated July 19, 1995 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-2348), Exhibit 10.41)
12.1	

Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company

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12.2	Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company
12.3	Computation of Ratios of Earnings to Fixed Charges for PG&E Corporation
13	The following portions of the 2013 Annual Report to Shareholders of PG&E Corporation and Pacific Gas and Electric Company are included: “Selected Financial Data,” “Glossary,” “Management's Discussion and Analysis of Financial Condition and Results of Operations,” financial statements of PG&E Corporation entitled “Consolidated Statements of Income,” “Consolidated Statements of Comprehensive Income,” “Consolidated Balance Sheets,” “Consolidated Statements of Cash Flows,” and “Consolidated Statements of Equity,” financial statements of Pacific Gas and Electric Company entitled “Consolidated Statements of Income,” “Consolidated Statements of Comprehensive Income,” “Consolidated Balance Sheets,” “Consolidated Statements of Cash Flows,” and “Consolidated Statements of Shareholders' Equity,” “Notes to the Consolidated Financial Statements,” “Quarterly Consolidated Financial Data (Unaudited),” “Management's Report on Internal Control Over Financial Reporting,” and “Report of Independent Registered Public Accounting Firm.”
21	Subsidiaries of the Registrant
23	Consent of Independent Registered Public Accounting Firm (Deloitte & Touche LLP)
24	Powers of Attorney
31.1	Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002
32.1**	Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

* Management contract or compensatory agreement.
** Pursuant to Item 601(b)(32) of SEC Regulation S-K, these exhibits are furnished rather than filed with this report.