PG&E Corporation and Pacific Gas and Electric Company

2012 Annual Report

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FINANCIAL HIGHLIGHTS[1]

PG&E Corporation

(unaudited, in millions, except share and per share amounts)	2012	2011
Operating Revenues	**$ 15,040**	**$ 14,956**
Income Available for Common Shareholders		
Earnings from operations[2]	1,367	1,438
Items impacting comparability[3]	(551)	(594)
Reported consolidated income available for common shareholders	**816**	**844**
Income Per Common Share, diluted		
Earnings from operations[2]	3.22	3.58
Items impacting comparability[3]	(1.30)	(1.48)
Reported consolidated net earnings per common share, diluted	**1.92**	**2.10**
Dividends Declared Per Common Share	**1.82**	**1.82**
Total Assets at December 31,	**$ 52,449**	**$ 49,750**
Number of common shares outstanding at December 31,	**431,436,673**	**412,257,082**

(1) This is a combined annual report of PG&E Corporation and Pacific Gas and Electric Company ("Utility"). PG&E Corporation's Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries.

(2) "Earnings from operations" is not calculated in accordance with the accounting principles generally accepted in the United States of America ("GAAP") and excludes items impacting comparability as described in Note (3) below.

(3) "Items impacting comparability" represent items that management does not consider part of normal, ongoing operations.

PG&E Corporation's earnings from operations for 2012 and 2011 exclude net costs of $812 million and $739 million, pre-tax, that the Utility incurred in connection with natural gas matters. These amounts included pipeline-related expenses that will not be recoverable through rates to validate safe operating pressures, conduct strength testing, and perform other activities associated with safety improvements to the Utility's natural gas pipeline system, as well as legal and regulatory costs. In addition, a charge was recorded in 2012 for disallowed capital expenditures related to the Utility's pipeline safety enhancement plan that are forecasted to exceed the California Public Utilities Commission's ("CPUC") authorized levels or that were specifically disallowed. Also included are estimated penalties associated with pending CPUC investigations related to various aspects of the Utility's natural gas operations and other potential enforcement matters, accruals for third-party claims arising from the natural gas pipeline accident that occurred in San Bruno, California on September 9, 2010, and a contribution to the City of San Bruno to support the community's recovery efforts after the accident. These costs were partially offset by insurance recoveries. See the table below.

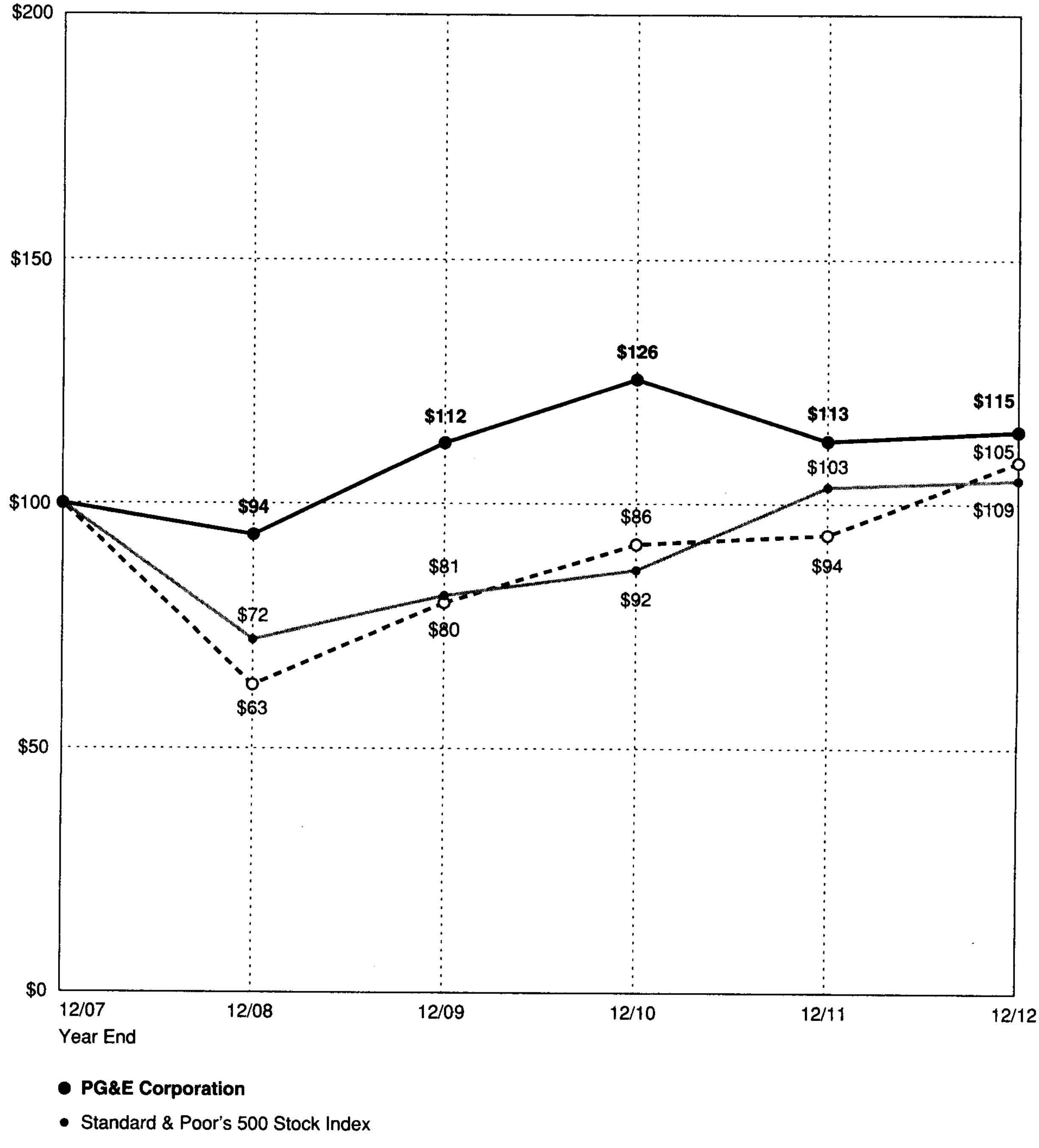
(pre-tax)	2012	2011
Pipeline-related expenses	$ 477	$ 483
Disallowed capital expenditures	353	—
Accrued penalties	17	200
Third-party claims	80	155
Insurance recoveries	(185)	(99)
Contribution to City of San Bruno	70	—
Natural gas matters	**$ 812**	**$ 739**

In addition, PG&E Corporation's earnings from operations for 2012 and 2011 also exclude $106 million and $125 million, pre-tax, for environmental remediation costs associated with the Utility's natural gas compressor site located near Hinkley, California.

PG&E Corporation common stock is traded on the New York Stock Exchange. The official New York Stock Exchange symbol for PG&E Corporation is "PCG."

COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL SHAREHOLDER RETURN[1]

This graph compares the cumulative total return on PG&E Corporation common stock (equal to dividends plus stock price appreciation) during the past five fiscal years with that of the Standard & Poor's 500 Stock Index and the Dow Jones Utilities Index.



(1) Assumes $100 invested on December 31, 2007 in PG&E Corporation common stock, the Standard & Poor's 500 Stock Index, and the Dow Jones Utilities Index, and assumes quarterly reinvestment of dividends. The total shareholder returns shown are not necessarily indicative of future returns.

SELECTED FINANCIAL DATA

(in millions, except per share amounts)	2012	2011	2010	2009	2008[1]
PG&E Corporation					
For the Year					
Operating revenues	$ 15,040	$ 14,956	$ 13,841	$ 13,399	$ 14,628
Operating income	1,693	1,942	2,308	2,299	2,261
Income from continuing operations	830	858	1,113	1,234	1,198
Earnings per common share from continuing operations, basic	1.92	2.10	2.86	3.25	3.23
Earnings per common share from continuing operations, diluted	1.92	2.10	2.82	3.20	3.22
Dividends declared per common share[2]	1.82	1.82	1.82	1.68	1.56
At Year-End					
Common stock price per share	$ 40.18	$ 41.22	$ 47.84	$ 44.65	$ 38.71
Total assets	52,449	49,750	46,025	42,945	40,860
Long-term debt (excluding current portion)	12,517	11,766	10,906	10,381	9,321
Capital lease obligations (excluding current portion)[3]	113	212	248	282	316
Energy recovery bonds (excluding current portion)[4]	—	—	423	827	1,213
Pacific Gas and Electric Company					
For the Year					
Operating revenues	$ 15,035	$ 14,951	$ 13,840	$ 13,399	$ 14,628
Operating income	1,695	1,944	2,314	2,302	2,266
Income available for common stock	797	831	1,107	1,236	1,185
At Year-End					
Total assets	51,923	49,242	45,679	42,709	40,537
Long-term debt (excluding current portion)	12,167	11,417	10,557	10,033	9,041
Capital lease obligations (excluding current portion)[3]	113	212	248	282	316
Energy recovery bonds (excluding current portion)[4]	—	—	423	827	1,213

(1) In 2008, PG&E Corporation recorded $154 million in income from discontinued operations related to losses incurred and synthetic fuel tax credits claimed by PG&E Corporation's former subsidiary, National Energy & Gas Transmission, Inc.

(2) Information about the frequency and amount of dividends and restrictions on the payment of dividends is set forth in "Liquidity and Financial Resources—Dividends" within "Management's Discussion and Analysis of Financial Condition and Results of Operations," and in PG&E Corporation's Consolidated Statements of Equity, the Utility's Consolidated Statements of Shareholders' Equity, and Note 6 of the Notes to the Consolidated Financial Statements.

(3) The capital lease obligations amounts are included in noncurrent liabilities—other in PG&E Corporation's and the Utility's Consolidated Balance Sheets.

(4) See Note 5 of the Notes to the Consolidated Financial Statements.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

PG&E Corporation, incorporated in California in 1995, is a holding company that conducts its business through Pacific Gas and Electric Company ("Utility"), a public utility operating in northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. The Utility served approximately 5.2 million electricity distribution customers and approximately 4.4 million natural gas distribution customers at December 31, 2012.

The Utility is regulated primarily by the California Public Utilities Commission ("CPUC") and the Federal Energy Regulatory Commission ("FERC"). In addition, the Nuclear Regulatory Commission ("NRC") oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities. The CPUC has jurisdiction over the rates and terms and conditions of service for the Utility's electricity and natural gas distribution operations, electric generation, and natural gas transportation and storage. The FERC has jurisdiction over the rates and terms and conditions of service governing the Utility's electric transmission operations and over the rates and terms and conditions of service governing the Utility on its interstate natural gas transportation contracts. The Utility also is subject to the jurisdiction of other federal, state, and local governmental agencies.

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 primary CPUC proceedings are the general rate case ("GRC") and the gas transmission and storage ("GT&S") rate case which generally occur every few years and result in revenue requirements that are set for multi-year periods. The CPUC also periodically conducts a cost of capital proceeding, where it determines the capital structure the Utility must maintain (i.e., the relative weightings of common equity, long-term debt, and preferred equity) and authorizes the Utility to earn a specific rate of return on each capital component, including a rate of return on equity ("ROE"). The authorized revenue requirements the CPUC sets in the GRC and GT&S rate cases are set at levels to provide the Utility an opportunity to earn its authorized rates of return on its "rate base"—the Utility's net investment in facilities, equipment, and other property used or useful in providing utility service to its customers. The primary FERC proceeding is the electric transmission owner ("TO") rate case which generally occurs on an annual basis. The FERC does not conduct a separate proceeding to authorize a specific rate of return on the Utility's FERC-jurisdictional assets. Instead, the rate of return is embedded in electric transmission revenues authorized by the FERC in TO rate cases. If the outcome of a TO rate case is reached through a FERC-approved settlement, the rate of return may not be specifically identified but rates would have been set to provide the Utility an opportunity to earn a reasonable rate of return. In other TO rate cases, the FERC may determine a specific rate of return after the FERC has held hearings and the parties have submitted briefs.

The Utility's ability to recover the revenue requirements that have been authorized by the CPUC in a GRC does not depend on the volume of the Utility's sales of electricity and natural gas services. This decoupling of revenues and sales eliminates volatility in the revenues earned by the Utility due to fluctuations in customer demand. However, fluctuations in operating and maintenance costs and the amount and timing of capital expenditures may impact the Utility's ability to earn its authorized rate of return. The Utility's ability to recover a portion of its revenue requirements that have been authorized by the CPUC in GT&S rate cases depends on the volume of natural gas transported. The Utility's ability to recover its revenue requirements that have been authorized by the FERC in a TO rate case depends on the volume of electricity sales.

The Utility also collects additional revenue requirements to recover certain costs that the CPUC has authorized the Utility to pass on to customers, including costs to purchase electricity and natural gas; and to fund public purpose, demand response, and customer energy efficiency programs. Therefore, although the timing and amount of these costs can impact the Utility's revenue, these costs generally do not impact net income. The Utility's revenues and net income, however, also may be affected by incentive ratemaking mechanisms that adjust rates depending on the extent to which the Utility meets or fails to meet certain performance criteria, such as customer energy efficiency goals.

The Utility's revenue requirements are set based on forecasted costs. Differences in actual costs could negatively affect the Utility's ability to earn its authorized return. Differences can occur for numerous reasons, including unanticipated costs related to storms, outages, catastrophic events, or to comply with new legislation, regulations, or orders; or if the Utility is required to pay third-party claims that are not recoverable through insurance. The CPUC could also disallow recovery of costs that it finds were not prudently or reasonably incurred. Finally, there may be some types of costs that the CPUC has determined will not be recoverable through rates or for which the Utility does not seek recovery, such as certain costs associated with the Utility's natural gas system, penalties associated with investigations or violations, and environmental-related liabilities associated with the Utility's natural gas compressor station located in Hinkley, California, as described more fully below.

This is a combined annual report of PG&E Corporation and the Utility, and includes separate Consolidated Financial Statements for each of these two entities. PG&E Corporation's Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries. The Utility's Consolidated Financial Statements include the accounts of the Utility and its wholly owned and controlled subsidiaries. This combined Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") of PG&E Corporation and the Utility should be read in conjunction with the Consolidated Financial Statements and the Notes to the Consolidated Financial Statements included in this annual report.

Key Factors Affecting Results of Operations and Financial Condition

PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows have continued to be materially affected by costs the Utility has incurred to improve the safety and reliability of its natural gas operations, as well as by costs related to the ongoing regulatory proceedings, investigations, and civil lawsuits that commenced following the rupture of one of the Utility's natural gas transmission pipelines in San Bruno, California on September 9, 2010 (the "San Bruno accident"). Through December 31, 2012, PG&E Corporation and the Utility have incurred cumulative charges of approximately $1.83 billion related to the San Bruno accident and natural gas matters. For 2012, this amount includes pipeline-related expenses of $477 million and capital expenditures of $353 million that will not be recoverable through rates. (See "CPUC Gas Safety Rulemaking Proceeding" below.) These matters and a number of other factors will continue to have a material negative impact on PG&E Corporation's and the Utility's future results of operations, financial condition, and cash flows.

- *The Outcome of Matters Related to the Utility's Natural Gas System.* The Utility forecasts that it will incur total pipeline-related costs ranging from $400 million to $500 million in 2013 that will not be recoverable through rates. These amounts include costs to perform work under the Utility's pipeline safety enhancement plan that were disallowed by the CPUC, as well as costs related to the Utility's multi-year effort to identify and remove encroachments from transmission pipeline rights-of-way; costs associated with the integrity of transmission pipelines and other gas-related work; and legal and regulatory expenses. (See "Operating and Maintenance" below.) In addition, PG&E Corporation and the Utility believe that the CPUC will impose penalties on the Utility of at least $200 million in connection with three pending CPUC investigations and other potential enforcement matters. The ultimate amount of penalties could be materially higher and the Utility may also incur costs to implement any remedial actions the CPUC may order the Utility to perform. (See "Pending CPUC Investigations and Enforcement Matters" below.) An ongoing investigation of the San Bruno accident by federal, state, and local authorities may result in the imposition of civil or criminal penalties on the Utility. (See "Criminal Investigation" below.) Finally, PG&E Corporation and the Utility believe it is reasonably possible that they may incur additional charges of up to $145 million for estimated third-party claims related to the San Bruno accident. (See "Third-Party Claims" below.)
- *Authorized Rate of Return, Capital Structure, and Financing Needs.* The CPUC has authorized the Utility's capital structure through 2015 for the Utility's electric generation, electric and natural gas distribution, and natural gas transmission and storage rate base, consisting of 52% common equity and 48% debt and preferred stock. The CPUC also authorized the Utility to earn a ROE of 10.40% beginning January 1, 2013, compared to the 11.35% previously authorized. (See "2013 Cost of Capital Proceeding" below.) In addition, the FERC has ordered the Utility to revise its requested revenue requirements and rates in its pending TO rate case to reflect a 9.1% ROE on electric transmission assets, rather than the 11.5% ROE originally requested by the Utility. (See "FERC Transmission Owner Rate Case" below.) PG&E Corporation contributes equity to the Utility as needed by the Utility to maintain its CPUC-authorized capital structure. The Utility has incurred significant expenses that are not recoverable through rates, which has increased the Utility's equity needs. In 2012, PG&E Corporation made equity contributions to the Utility of $885 million, which were funded primarily through common stock issuances that had a material dilutive effect on PG&E Corporation's earnings per common share. PG&E Corporation forecasts that it will issue additional common stock of approximately $1 billion in 2013 to fund the Utility's equity needs. Issuances that are used to fund the Utility's equity needs that are attributable to unrecoverable costs and penalties will have an additional dilutive effect. The Utility's debt and equity financing needs also will be affected by other factors, including the timing and amount of the

Utility's capital expenditures, operating expenses, and collateral requirements associated with price risk management activities. The Utility forecasts that capital spending will total approximately $5.1 billion in 2013, including capital projects related to its pipeline safety enhancement plan. PG&E Corporation's and the Utility's ability to access the capital markets and the terms and rates of future financings could be affected by changes in their respective credit ratings, the outcome of natural gas matters, general economic and market conditions, and other factors. (See "Liquidity and Financial Resources" below.)

- *The Timing and Outcome of Ratemaking Proceedings.* The Utility's financial results are affected by the timing and outcome of ratemaking proceedings. The CPUC issued decisions in 2011 that determined the majority of the Utility's base revenue requirements through 2013. In November 2012, the Utility filed its 2014 GRC application with the CPUC to request that the CPUC determine the amount of revenue requirements the Utility is authorized to collect through rates for its electric generation operations and electric and natural gas distribution from 2014 through 2016. The Utility has requested that the CPUC increase the Utility's base revenues for 2014 by $1.28 billion over the comparable revenues for 2013 that were previously authorized. (See "2014 General Rate Case" below.) The FERC is expected to determine in the pending TO rate case the amount of electric transmission revenues the Utility can recover beginning in May 2013. (See "FERC Transmission Owner Rate Case" below.) In addition, in late 2013, the Utility expects to file an application with the CPUC to initiate the Utility's 2015 GT&S rate case in which the CPUC will determine the rates, and terms and conditions of the Utility's gas transmission and storage services beginning January 1, 2015. The outcome of these ratemaking proceedings can be affected by many factors, including general economic conditions, the level of customer rates, regulatory policies, and political considerations.
- *The Ability of the Utility to Control Operating Costs and Capital Expenditures.* Rates are primarily set based on forecasts and assumptions about the amount of operating costs and capital expenditures the Utility will incur in future periods. PG&E Corporation's and the Utility's net income is negatively affected when the revenues provided by rates are not sufficient for the Utility to recover the costs it actually incurs. In 2012, in addition to the non-recoverable costs related to the Utility's natural gas system described above, the Utility incurred costs of $255 million to improve the safety and reliability of its electric and natural gas operations that it will not recover through rates. The Utility forecasts that it will incur approximately $250 million to make additional incremental improvements in 2013 that it will not recover through rates. (See "Operating and Maintenance" below.) In addition, 2013 net income will be negatively affected by costs related to capital expenditures that the Utility forecasts will exceed authorized levels. Any future increase in the Utility's environmental-related liabilities that are not recoverable through rates, such as costs associated with its natural gas compressor station located in Hinkley, California, also will negatively affect PG&E Corporation's and the Utility's net income. For 2012, the Utility recorded total charges to net income of $127 million for environmental remediation related to the Hinkley site. (See "Environmental Matters" below.) Other differences between the amount or timing of the Utility's actual costs and forecasted or authorized amounts may also affect the Utility's ability to earn its authorized ROE.

Summary of Changes in Earnings per Common Share and Income Available for Common Shareholders for 2012

The following table is a summary reconciliation of the key changes, after-tax, in PG&E Corporation's income available for common shareholders and earnings per common share for the year ended December 31, 2012:

(in millions, except per share amounts)	Earnings	Earnings Per Common Share (Diluted)
Income Available for Common Shareholders—2011	$ 844	$ 2.10
Increase in rate base earnings	80	0.19
Natural gas matters(1)	32	0.15
Storm and outage expenses	28	0.06
Litigation and regulatory matters	27	0.06
Gas transmission revenues	15	0.04
Environmental-related costs	11	0.03
Planned incremental work	(151)	(0.36)
Employee operational performance incentive	(33)	(0.08)
Energy efficiency incentive	(3)	(0.01)
Increase in shares outstanding(2)	—	(0.19)
Other	(34)	(0.07)
Income Available for Common Shareholders—2012	**$ 816**	**$ 1.92**

(1) The Utility incurred charges related to natural gas matters of $812 million and $739 million, pre-tax, for 2012 and 2011, respectively. The amount shown above represents the favorable tax impact attributable to the lower amount of non-deductible penalties recorded in 2012 of $17 million, as compared to $200 million recorded in 2011.

(2) Represents the impact of a higher number of shares outstanding at December 31, 2012, compared to the number of shares outstanding at December 31, 2011. PG&E Corporation issues shares to fund its equity contributions to the Utility to maintain the Utility's capital structure and fund operations, including expenses related to natural gas matters. This has no dollar impact on earnings.

CAUTIONARY LANGUAGE REGARDING FORWARD-LOOKING STATEMENTS

This 2012 Annual Report contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions which are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report.

These forward-looking statements relate to, among other matters, estimated losses associated with various investigations; estimated losses and insurance recoveries associated with the civil litigation arising from the San Bruno accident; forecasts of costs the Utility will incur to make safety and reliability improvements, including costs to perform work under the pipeline safety enhancement plan, that the Utility will not recover through rates; forecasts of capital expenditures; estimates and assumptions used in critical accounting policies, including those relating to environmental remediation, tax, litigation, third-party claims, and other liabilities; and the level of future equity or debt issuances. These statements are also identified by words such as "assume," "expect," "intend," "forecast," "plan," "project," "believe," "estimate," "predict," "anticipate," "may," "should," "would," "could," "potential" and similar expressions. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

- the timing and terms of the resolution of pending investigations and enforcement matters related to the Utility's natural gas system operating practices and the San Bruno accident, including the ultimate amount of penalties the Utility will be required to pay, the cost of any remedial actions the Utility may be ordered to perform, and whether the resolution is reached through settlement negotiations, or a fully litigated proceeding; the ultimate amount of third-party claims associated with the San Bruno accident and the timing and amount of related insurance recoveries; the ultimate amount of punitive damages, if any, the Utility may incur related to third-party claims; and the ultimate amount of civil or criminal penalties, if any, the Utility may incur related to the criminal investigation;
- the outcomes of current ratemaking proceedings, such as the 2014 GRC and the pending TO rate case; the outcome of future ratemaking and regulatory proceedings, such as the 2015 GT&S rate case, and the CPUC's natural gas rulemaking proceeding in which the CPUC will consider the Utility's proposed scope, timing, and

cost recovery mechanisms that will apply to the second phase of the pipeline safety enhancement plan; and the outcomes of other ratemaking and regulatory proceedings;

- the ultimate amount of costs the Utility incurs in the future that are not recovered through rates, including costs to perform work under the pipeline safety enhancement plan, to identify and remove encroachments from transmission pipeline easements, and to perform incremental work to improve the safety and reliability of electric and natural gas operations;
- the outcome of future investigations or proceedings that may be commenced by the CPUC or other regulatory authorities relating to the Utility's compliance with laws, rules, regulations, or orders applicable to the operation, inspection, and maintenance of its electric and gas facilities;
- whether PG&E Corporation and the Utility are able to repair the reputational harm that they have suffered, and may suffer in the future, due to the negative publicity surrounding the San Bruno accident, the related civil litigation, and the pending investigations, including any charge or finding of criminal liability;
- the level of equity contributions that PG&E Corporation must make to the Utility to enable the Utility to maintain its authorized capital structure as the Utility incurs charges and costs, including costs associated with natural gas matters and penalties imposed in connection with the pending investigations, that are not recoverable through rates or insurance;
- the impact of environmental remediation laws, regulations, and orders; the ultimate amount of costs incurred to discharge the Utility's known and unknown remediation obligations; the extent to which the Utility is able to recover compliance and remediation costs from third parties or through rates or insurance; and the ultimate amount of costs the Utility incurs in connection with environmental remediation liabilities that are not recoverable through rates or insurance, such as the remediation costs associated with the Utility's natural gas compressor station site located near Hinkley, California;
- the impact of new legislation or NRC regulations, recommendations, policies, decisions, or orders relating to the operations, seismic design, security, safety, or decommissioning of nuclear facilities, including the Utility's Diablo Canyon nuclear power plant ("Diablo Canyon"), or relating to the storage of spent nuclear fuel, cooling water intake, or other issues; and the ability of the Utility to relicense the Diablo Canyon units;
- the impact of weather-related conditions or events (such as storms, tornadoes, floods, drought, solar or electromagnetic events, and wildland and other fires), natural disasters (such as earthquakes, tsunamis, and pandemics), and other events (such as explosions, fires, accidents, mechanical breakdowns, equipment failures, human errors, and labor disruptions), as well as acts of terrorism, war, or vandalism, including cyber-attacks, that can cause unplanned outages, reduce generating output, disrupt the Utility's service to customers, or damage or disrupt the facilities, operations, or information technology and systems owned by the Utility, its customers, or third parties on which the Utility relies; and subject the Utility to third-party liability for property damage or personal injury, or result in the imposition of civil, criminal, or regulatory penalties on the Utility;
- the impact of environmental laws and regulations aimed at the reduction of carbon dioxide and other greenhouse gases ("GHG"s), and whether the Utility is able to recover associated compliance costs, including the cost of emission allowances and offsets, that the Utility may incur under cap-and-trade regulations;
- changes in customer demand for electricity ("load") and natural gas resulting from unanticipated population growth or decline in the Utility's service area, general and regional economic and financial market conditions, the extent of municipalization of the Utility's electric distribution facilities, changing levels of "direct access" customers who procure electricity from alternative energy providers, changing levels of customers who purchase electricity from governmental bodies that act as "community choice aggregators," and the development of alternative energy technologies including self-generation and distributed generation technologies;
- the adequacy and price of electricity, natural gas, and nuclear fuel supplies; the extent to which the Utility can manage and respond to the volatility of energy commodity prices; the ability of the Utility and its counterparties to post or return collateral in connection with price risk management activities; and whether the Utility is able to recover timely its energy commodity costs through rates;
- whether the Utility's information technology, operating systems and networks, including the advanced metering system infrastructure, customer billing, financial, and other systems, can continue to function accurately while

meeting regulatory requirements; whether the Utility is able to protect its operating systems and networks from damage, disruption, or failure caused by cyber-attacks, computer viruses, or other hazards; whether the Utility's security measures are sufficient to protect confidential customer, vendor, and financial data contained in such systems and networks; and whether the Utility can continue to rely on third-party vendors and contractors that maintain and support some of the Utility's operating systems;

- the extent to which costs incurred in connection with third-party claims or litigation are not recoverable through insurance, rates, or from other third parties;
- the ability of PG&E Corporation and the Utility to access capital markets and other sources of debt and equity financing in a timely manner on acceptable terms;
- the impact of federal or state laws or regulations, or their interpretation, on energy policy and the regulation of utilities and their holding companies, including how the CPUC interprets and enforces the financial and other conditions imposed on PG&E Corporation when it became the Utility's holding company, and whether the outcome of proceedings and investigations relating to the Utility's natural gas operations affects the Utility's ability to make distributions to PG&E Corporation in the form of dividends or share repurchases; and, in turn, PG&E Corporation's ability to pay dividends;
- the outcome of federal or state tax audits and the impact of any changes in federal or state tax laws, policies, or regulations; and
- the impact of changes in generally accepted accounting principles, standards, rules, or policies, including those related to regulatory accounting, and the impact of changes in their interpretation or application.

For more information about 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, results of operations, and cash flows, see "Risk Factors" below. PG&E Corporation and the Utility do not undertake an obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

RESULTS OF OPERATIONS

The table below details certain items from the accompanying Consolidated Statements of Income for 2012, 2011, and 2010:

(in millions)	Year ended December 31, 2012	2011	2010
Utility			
Electric operating revenues	$ 12,014	$ 11,601	$ 10,644
Natural gas operating revenues	3,021	3,350	3,196
Total operating revenues	**15,035**	**14,951**	**13,840**
Cost of electricity	4,162	4,016	3,898
Cost of natural gas	861	1,317	1,291
Operating and maintenance	6,045	5,459	4,432
Depreciation, amortization, and decommissioning	2,272	2,215	1,905
Total operating expenses	**13,340**	**13,007**	**11,526**
Operating income	1,695	1,944	2,314
Interest income	6	5	9
Interest expense	(680)	(677)	(650)
Other income, net	88	53	22
Income before income taxes	1,109	1,325	1,695
Income tax provision	298	480	574
Net income	811	845	1,121
Preferred stock dividend requirement	14	14	14
Income Available for Common Stock	**$ 797**	**$ 831**	**$ 1,107**
PG&E Corporation, Eliminations, and Other[(1)]			
Operating revenues	$ 5	$ 5	$ 1
Operating expenses	7	7	7
Operating loss	(2)	(2)	(6)
Interest income	1	2	—
Interest expense	(23)	(23)	(34)
Other (expense) income, net	(18)	(4)	5
Loss before income taxes	(42)	(27)	(35)
Income tax benefit	(61)	(40)	(27)
Net income (loss)	**$ 19**	**$ 13**	**$ (8)**
Consolidated Total			
Operating revenues	$ 15,040	$ 14,956	$ 13,841
Operating expenses	13,347	13,014	11,533
Operating income	1,693	1,942	2,308
Interest income	7	7	9
Interest expense	(703)	(700)	(684)
Other income, net	70	49	27
Income before income taxes	1,067	1,298	1,660
Income tax provision	237	440	547
Net income	830	858	1,113
Preferred stock dividend requirement of subsidiary	14	14	14
Income Available for Common Shareholders	**$ 816**	**$ 844**	**$ 1,099**

(1) PG&E Corporation eliminates all intercompany transactions in consolidation.

The following presents the Utility's operating results for 2012, 2011, and 2010.

Electric Operating Revenues

The Utility's electric operating revenues consist of amounts charged to customers for electricity generation, transmission and distribution services, as well as amounts charged to customers to recover the cost of electricity procurement and the cost of public purpose, energy efficiency, and demand response programs.

The following table provides a summary of the Utility's total electric operating revenues:

(in millions)	2012	2011	2010
Revenues excluding passed-through costs	$ 6,280	$ 6,150	$ 5,473
Revenues for recovery of passed-through costs	5,734	5,451	5,171
Total electric operating revenues	**$ 12,014**	**$ 11,601**	**$ 10,644**

The Utility's total electric operating revenues, including revenues intended to recover costs that are passed through to customers, increased by $413 million, or 4%, in 2012 compared to 2011. Revenues intended to recover costs that are passed through to customers and do not impact net income increased by $283 million, primarily due to an increase in the cost of electricity (See "Cost of Electricity" below), the cost of public purpose programs, and pension contributions. Electric operating revenues, excluding revenues intended to recover costs that are passed through to customers, increased by $130 million, primarily due to an increase in base revenues as authorized in the 2011 GRC and in the TO rate case.

The Utility's total electric operating revenues, including revenues intended to recover costs that are passed through to customers, increased by $957 million, or 9%, in 2011 compared to 2010. Revenues intended to recover costs that are passed through to customers and do not impact net income increased by $280 million, primarily due to increases in the cost of electricity (see "Cost of Electricity" below), the cost of public purpose programs, and pension contributions. Electric operating revenues, excluding revenues intended to recover costs that are passed through to customers, increased by $677 million. The increase is primarily due to additional base revenues that were authorized by the CPUC in the 2011 GRC and for various separately funded projects, and authorized by the FERC in the TO rate case that became effective March 1, 2011.

The Utility's future electric operating revenues, excluding revenues intended to recover costs that are passed through to customers, are expected to increase in 2013 as authorized by the CPUC in the 2011 GRC. This increase to future revenues will be offset by the lower revenues authorized by the CPUC in the 2013 Cost of Capital proceeding. (See "Regulatory Matters" below.) Additionally, the Utility's future electric operating revenues are expected to be impacted by revenues authorized by the FERC in the TO rate case (these increased revenues are expected to become effective on May 1, 2013) and by the CPUC in the 2014 GRC, which was filed on November 14, 2012. Future electric operating revenues will also be impacted by the cost of electricity and other revenues intended to recover costs that are passed through to customers.

Cost of Electricity

The Utility's cost of electricity includes the costs of power purchased from third parties, transmission, fuel used in its own generation facilities, fuel supplied to other facilities under power purchase agreements, and realized gains and losses on price risk management activities. (See Note 10 of the Notes to the Consolidated Financial Statements.) The Utility's cost of electricity is passed through to customers. The Utility's cost of electricity excludes non-fuel costs associated with operating the Utility's own generation facilities and electric transmission and distribution system, which are included in operating and maintenance expense in the Consolidated Statements of Income.

The following table provides a summary of the Utility's cost of electricity and the total amount and average cost of purchased power:

(in millions)	2012	2011	2010
Cost of purchased power	$ 3,873	$ 3,719	$ 3,647
Fuel used in own generation facilities	289	297	251
Total cost of electricity	**$ 4,162**	**$ 4,016**	**$ 3,898**
Average cost of purchased power per kWh[(1)]	$ 0.079	$ 0.089	$ 0.081
Total purchased power (in millions of kWh)	**48,933**	**41,958**	**44,837**

(1) Kilowatt-hour

The Utility's total cost of electricity increased by $146 million, or 4%, in 2012 compared to 2011, primarily due to an increase in the volume of power purchased as customer demand increased and higher costs to purchase renewable energy. The higher cost of electricity was partially offset by the decrease in the average cost of purchased power which reflected lower spot prices. The volume of power the Utility purchases is driven by customer demand, the availability of the Utility's own generation facilities, and the cost effectiveness of each source of electricity.

The Utility's total cost of electricity increased by $118 million, or 3%, in 2011 compared to 2010. The increase was due to an increase in the average cost of purchased power resulting from increased renewable energy deliveries and higher transmission costs.

Various factors will affect the Utility's future cost of electricity, including the market prices for electricity and natural gas, the availability of Utility-owned generation, and changes in customer demand. Additionally, the cost of electricity is expected to be impacted by the higher cost of procuring renewable energy as the Utility increases the amount of its renewable energy deliveries to comply with current and future California law and regulatory requirements. The Utility's future cost of electricity also will be affected by legislation and rules applicable to GHG emissions. (See "Environmental Matters" below.)

Natural Gas Operating Revenues

The Utility's natural gas operating revenues consist of amounts charged for transportation, distribution, and storage services, as well as amounts charged to customers to recover the cost of natural gas procurement and public purpose programs.

The following table provides a summary of the Utility's natural gas operating revenues:

(in millions)	2012	2011	2010
Revenues excluding passed-through costs	$ 1,772	$ 1,696	$ 1,627
Revenues for recovery of passed-through costs	1,249	1,654	1,569
Total natural gas operating revenues	**$ 3,021**	**$ 3,350**	**$ 3,196**

The Utility's natural gas operating revenues, including revenues intended to recover costs that are passed through to customers, decreased by $329 million, or 10%, in 2012 compared to 2011. Revenues intended to recover costs that are passed through to customers and do not impact net income decreased by $405 million primarily due to a decrease in the cost of natural gas. Natural gas operating revenues, excluding revenues intended to recover costs that are passed through to customers, increased by $76 million, primarily due to an increase in base revenues as authorized in the 2011 GT&S rate case and the 2011 GRC and increases in natural gas storage revenues.

The Utility's natural gas operating revenues, including revenues intended to recover costs that are passed through to customers, increased by $154 million, or 5%, in 2011 compared to 2010. Revenues intended to recover costs that are passed through to customers and do not impact net income increased by $85 million, primarily due to an increase in the costs of public purpose programs and pension contributions. Natural gas operating revenues, excluding revenues intended to recover costs that are passed through to customers, increased by $69 million, primarily due to an increase in authorized base revenue, partially offset by a decrease in natural gas storage revenues. (The Utility's storage facilities were at capacity throughout 2011 and less gas was transported from storage due to the milder weather that prevailed in 2011 compared to 2010. As result, the Utility was unable to accept more gas for storage.)

The Utility's operating revenues for natural gas transmission services are expected to increase for 2013 and 2014 as authorized by the CPUC in the 2011 GT&S rate case and will also be impacted by revenues authorized by the CPUC in the 2014 GRC. The Utility's revenues for natural gas distribution services in 2013, excluding revenues intended to recover passed-through costs, will also reflect revenue increases authorized by the CPUC in the 2011 GRC. These increases to future revenues will be offset by the lower revenues authorized by the CPUC in the 2013 Cost of Capital proceeding. (See "Regulatory Matters" below.) Additionally, the Utility's future operating revenues will reflect those revenues authorized by the CPUC under the Utility's pipeline safety enhancement plan. (See "Natural Gas Matters" below.) The Utility's future gas operating revenues also will be impacted by the cost of natural gas, natural gas throughput volume, and other factors.

Cost of Natural Gas

The Utility's cost of natural gas includes the costs of procurement, storage, transportation of natural gas and realized gains and losses on price risk management activities. (See Note 10 of the Notes to the Consolidated Financial Statements.) The Utility's cost of natural gas is passed through to customers. The Utility's cost of natural gas excludes the cost of operating the Utility's gas transmission and distribution system, which is included in operating and maintenance expense in the Consolidated Statements of Income.

The following table provides a summary of the Utility's cost of natural gas:

(in millions)	2012	2011	2010
Cost of natural gas sold	$ 676	$ 1,136	$ 1,119
Transportation cost of natural gas sold	185	181	172
Total cost of natural gas	**$ 861**	**$ 1,317**	**$ 1,291**
Average cost per Mcf of natural gas sold	$ 2.91	$ 4.49	$ 4.69
Total natural gas sold (in millions of Mcf)[1]	232	253	249

(1) One thousand cubic feet

The Utility's total cost of natural gas decreased by $456 million, or 35%, in 2012 compared to 2011, primarily due to a lower average market price of natural gas during 2012.

The Utility's total cost of natural gas increased by $26 million, or 2%, in 2011 compared to 2010, primarily due to the absence of a $49 million refund the Utility received in 2010 to be passed through to customers as part of a litigation settlement.

The Utility's future cost of natural gas will be affected by the market price of natural gas and changes in customer demand. In addition, the Utility's future cost of natural gas may be affected by federal or state legislation or rules to regulate the GHG emissions from the Utility's natural gas transportation and distribution facilities and from natural gas consumed by the Utility's customers.

Operating and Maintenance

Operating and maintenance expenses consist mainly of the Utility's costs to operate and maintain its electricity and natural gas facilities, customer billing and service expenses, the cost of public purpose programs, and administrative and general expenses. The Utility's ability to earn its authorized rate of return depends in part on its ability to manage its expenses and to achieve operational and cost efficiencies.

The Utility's operating and maintenance expenses (including costs passed through to customers) increased by $586 million, or 11%, from $5,459 million in 2011 to $6,045 million in 2012. Excluding costs passed through to customers, operating and maintenance expense increased $488 million, primarily due to costs incurred to improve the safety and reliability of electric and natural gas operations that were $255 million higher than amounts assumed under the 2011 rate cases. The remaining increase was attributable to $73 million of net costs associated with natural gas matters (see table below), $56 million of employee operational performance incentive, and $26 million of planned maintenance costs associated with the Gateway Generating Station. These costs were partially offset by a $25 million decrease in legal and regulatory matters, including penalties associated with the Rancho Cordova accident in 2011. Costs that are passed through to customers and do not impact net income increased by $98 million, primarily due to costs associated with advanced electric and gas meters that use SmartMeter™ technology and pension contributions.

The Utility's operating and maintenance expenses (including costs passed through to customers) increased by $1,027 million, or 23%, from $4,432 million in 2010 to $5,459 million in 2011. Excluding costs passed through to customers, operating and maintenance expenses increased by $817 million in 2011 compared to 2010, primarily due to a $456 million increase in costs for natural gas matters. (See table below.) The remaining increase in operating and maintenance costs was attributable to a number of factors, including $122 million for estimated environmental remediation costs and other liabilities associated with Hinkley natural gas compressor site and approximately $82 million for labor and other maintenance-related costs, primarily associated with higher storm costs. Additionally, legal and regulatory matters increased $32 million, including penalties associated with the Rancho Cordova accident. Costs that are passed through to customers and do not impact net income increased by $210 million primarily due to pension expense, public purpose programs, and meter reading.

The following table provides a summary of the Utility's costs associated with natural gas matters, included in operating and maintenance expenses:

(in millions)	2012	2011	2010	Total
Pipeline-related expenses	$ 477	$ 483	$ 63	$ 1,023
Disallowed capital expenditures	353	—	—	353
Accrued penalties	17	200	—	217
Third-party claims	80	155	220	455
Insurance recoveries	(185)	(99)	—	(284)
Contribution to City of San Bruno	70	—	—	70
Total natural gas matters	**$ 812**	**$ 739**	**$ 283**	**$ 1,834**

The Utility incurred net costs of $812 million, $739 million, and $283 million during 2012, 2011 and 2010, respectively, in connection with natural gas matters that are not recoverable through rates. These amounts primarily include pipeline-related expenses which consist of costs to validate safe operating pressures, conduct strength testing, and perform other work (including work within the scope of the Utility's pipeline safety enhancement plan), as well as associated legal and regulatory costs. In addition, a $353 million charge was recorded in 2012 for disallowed capital expenditures related to the Utility's pipeline safety enhancement plan that are forecasted to exceed the CPUC's authorized levels or that were specifically disallowed. Also included above are estimated penalties related to the CPUC's pending investigations and other potential enforcement matters, accruals for third-party claims related to the San Bruno accident, and a contribution to the City of San Bruno. These costs were partially offset by insurance recoveries related to third-party claims. (See "Natural Gas Matters" below.)

The Utility forecasts that it will incur total pipeline-related costs ranging from $400 million to $500 million in 2013 that will not be recoverable through rates. These amounts include costs to perform work under the Utility's pipeline safety enhancement plan that were disallowed by the CPUC. These amounts also include emerging work related to the Utility's multi-year effort to identify and remove encroachments (such as building structures and vegetation overgrowth) from transmission pipeline rights-of-way, as well as costs associated with the integrity of transmission pipelines and other gas-related work. The Utility also expects it will continue to incur legal and regulatory expenses associated with its natural gas system. The Utility may incur costs to implement any remedial actions the CPUC may order the Utility to perform. (See "Natural Gas Matters—Pending CPUC Investigations and Enforcement Matters" below.)

Future operating and maintenance expense will also continue to be affected by other costs associated with natural gas matters that are not recoverable through rates, including any additional charges for third-party claims arising from the San Bruno accident that are not recoverable through insurance, additional charges for civil or criminal penalties, or punitive damages, if any, that may be imposed on the Utility. (See "Natural Gas Matters" below.)

The Utility forecasts that it will incur expenses in 2013 that are approximately $250 million higher than amounts assumed under the 2011 GRC and GT&S rate case as the Utility works to improve the safety and reliability of its electric and natural gas operations.

Depreciation, Amortization, and Decommissioning

The Utility's depreciation and amortization expense consists of depreciation and amortization on plant and regulatory assets, and decommissioning expenses associated with fossil fuel-fired generation facilities and nuclear power facilities. The Utility's depreciation, amortization, and decommissioning expenses increased by $57 million, or 3%, in 2012 compared to 2011, primarily due to capital additions.

The Utility's depreciation, amortization, and decommissioning expenses increased by $310 million, or 16%, in 2011 compared to 2010, primarily due to capital additions and an increase in depreciation rates as authorized by the 2011 GRC and 2011 GT&S rate cases.

The Utility's depreciation expense for future periods is expected to be affected as a result of changes in capital expenditures and the implementation of new depreciation rates as authorized by the CPUC in future GRCs and GT&S rate cases. Future TO rate cases authorized by the FERC will also have an impact on depreciation rates.

Interest Income and Interest Expense

There were no material changes to interest income and interest expense for 2012 compared to 2011 or for 2011 compared to 2010.

Other Income, Net

The Utility's other income, net increased by $35 million, in 2012 compared to 2011. The increase was primarily due to an increase in allowance for equity funds used during construction ("AFUDC") as the average balance of construction work in progress was higher in 2012 as compared to 2011.

The Utility's other income, net increased by $31 million, in 2011 compared to 2010 when the Utility incurred costs to support a California ballot initiative that appeared on the June 2010 ballot that were not recoverable in rates. The increase was partially offset by a decrease in AFUDC as the average balance of construction work in progress was lower in 2011 compared to 2010.

Income Tax Provision

The Utility's income tax provision decreased by $182 million, or 38%, in 2012 compared to 2011. The effective tax rates were 27% and 36% for 2012 and 2011, respectively. The effective tax rates for 2012 decreased compared to 2011, primarily due to lower non-tax deductible penalties related to natural gas matters, and higher state benefits received and deductions in 2012, including a benefit associated with a California research and development claim, with no comparable amount in 2011; a higher California tax deduction resulting from an accounting method change for repairs as compared to 2011; and a California tax benefit associated with shorter depreciable lives related to meters that use SmartMeter™ technology recorded in 2012 with no comparable amount in 2011.

The Utility's income tax provision decreased by $94 million, or 16%, in 2011 compared to 2010. The effective tax rates were 36% and 34% for 2011 and 2010, respectively. The effective tax rate for 2011 increased as compared to 2010, mainly due to non- tax deductible penalties related to natural gas matters recorded in 2011, with no comparable penalties recorded in 2010, partially offset by a benefit associated with a loss carryback recorded in 2011 and the reversal of a deferred tax asset attributable to the Medicare Part D subsidy, which affected the tax provision balance in 2010, with no comparable effect in 2011.

The differences between the Utility's income taxes and amounts calculated by applying the federal statutory rate to income before income tax expense for continuing operations for 2012, 2011, and 2010 were as follows:

	2012	2011	2010
Federal statutory income tax rate	35.0%	35.0%	35.0%
Increase (decrease) in income tax rate resulting from:			
State income tax (net of federal benefit)	(3.0)	1.6	1.0
Effect of regulatory treatment of fixed asset differences	(3.9)	(4.2)	(3.0)
Tax credits	(0.6)	(0.5)	(0.4)
Benefit of loss carryback	(0.4)	(2.1)	—
Non deductible penalties	0.5	6.3	0.2
Other, net	(0.8)	0.1	1.1
Effective tax rate	**26.8%**	**36.2%**	**33.9%**

PG&E Corporation, Eliminations, and Other

Operating Revenues and Expenses

PG&E Corporation's revenues consist mainly of billings to its affiliates for services rendered, all of which are eliminated in consolidation. PG&E Corporation's operating expenses consist mainly of employee compensation and payments to third parties for goods and services. Generally, PG&E Corporation's operating expenses are allocated to affiliates. These allocations are made without mark-up and are eliminated in consolidation. PG&E Corporation's interest expense relates to PG&E Corporation's outstanding senior notes, and is not allocated to affiliates.

There were no material changes to PG&E Corporation's operating results in 2012 compared to 2011 and 2011 compared to 2010.

LIQUIDITY AND FINANCIAL RESOURCES

Overview

The Utility's ability to fund operations and make distributions to PG&E Corporation depends on the levels of its operating cash flows and access to the capital and credit markets. The levels of the Utility's operating cash and short-term debt fluctuate as a result of seasonal load, volatility in energy commodity costs, collateral requirements related to price risk management activities, the timing and amount of tax payments or refunds, and the timing and effect of regulatory decisions and long-term financings, among other factors. The Utility generally utilizes equity contributions from PG&E Corporation and long-term senior unsecured debt issuances to maintain its CPUC-authorized capital structure. The Utility relies on short-term debt, including commercial paper, to fund temporary financing needs. The CPUC authorizes the aggregate amount of long-term debt and short-term debt that the Utility may issue and authorizes the Utility to recover its related debt financing costs. The Utility has short-term borrowing authority of $4.0 billion, including $500 million that is restricted to certain contingencies.

PG&E Corporation's ability to fund operations, make scheduled principal and interest payments, fund Utility equity contributions as needed for the Utility to maintain its CPUC-authorized capital structure, and pay dividends primarily depends on the level of cash distributions received from the Utility and PG&E Corporation's access to the capital and credit markets.

PG&E Corporation's and the Utility's credit ratings may affect their access to the credit and capital markets and their respective financing costs in those markets. Credit rating downgrades may increase the cost of short-term borrowing, including the Utility's commercial paper and the costs associated with their respective credit facilities, and long-term debt.

PG&E Corporation and the Utility maintain separate bank accounts and primarily invest their cash in money market funds. The following table summarizes PG&E Corporation's and the Utility's cash positions:

(in millions)	December 31, 2012	2011
PG&E Corporation	$ 207	$ 209
Utility	194	304
Total consolidated cash and cash equivalents	**$ 401**	**$ 513**

In addition to these cash and cash equivalents, PG&E Corporation and the Utility hold restricted cash that primarily consists of cash held in escrow pending the resolution of the remaining disputed claims that were filed in the Utility's reorganization proceeding under Chapter 11 of the U.S. Bankruptcy Code ("Chapter 11"). (See Note 13 of the Notes to the Consolidated Financial Statements.)

Revolving Credit Facilities and Commercial Paper Program

The following table summarizes PG&E Corporation's and the Utility's outstanding borrowings under their revolving credit facilities and the Utility's commercial paper program at December 31, 2012:

(in millions)	Termination Date	Facility Limit	Letters of Credit Outstanding	Borrowings	Commercial Paper	Facility Availability
PG&E Corporation	May 2016	$ 300(1)	$ —	$ 120	$ —	$ 180
Utility	May 2016	3,000(2)	266	—	370(3)	2,364(3)
Total revolving credit facilities		**$ 3,300**	**$ 266**	**$ 120**	**$ 370**	**$ 2,544**

(1) Includes a $100 million sublimit for letters of credit and a $100 million commitment for loans that are made available on a same-day basis and are repayable in full within 7 days.

(2) Includes a $1.0 billion sublimit for letters of credit and a $300 million commitment for loans that are made available on a same-day basis and are repayable in full within 7 days.

(3) The Utility treats the amount of its outstanding commercial paper as a reduction to the amount available under its revolving credit facility.

For 2012, the average outstanding borrowings under PG&E Corporation's revolving credit facility were $21 million and the maximum outstanding balance during the year was $120 million. For 2012, the Utility's average outstanding commercial paper balance was $665 million and the maximum outstanding balance during the year was $1.4 billion. The Utility did not borrow under its credit facility in 2012.

The revolving credit facilities include usual and customary covenants for revolving credit facilities of this type, including covenants limiting liens to those permitted under PG&E Corporation's and the Utility's senior note indentures, mergers, sales of all or substantially all of PG&E Corporation's and the Utility's assets, and other fundamental changes. In addition, the revolving credit facilities require that PG&E Corporation and the Utility maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% as of the end of each fiscal quarter. PG&E Corporation's revolving credit facility agreement also requires that PG&E Corporation own, directly or indirectly, at least 80% of the common stock and at least 70% of the voting capital stock of the Utility. At December 31, 2012, PG&E Corporation and the Utility were in compliance with all covenants under their respective revolving credit facilities.

See Note 4 of the Notes to the Consolidated Financial Statements for additional information about the credit facilities and the Utility's commercial paper program.

2012 Financings

Utility

The following table summarizes long-term debt issuances in 2012:

(in millions)	Issue Date	Amount
Senior Notes		
4.45%, due 2042	April 16	$ 400
2.45%, due 2022	August 16	400
3.75%, due 2042	August 16	350
Total debt issuances in 2012		**$ 1,150**

The net proceeds from the issuance of Utility senior notes in 2012 were used to repay a portion of outstanding commercial paper, and for general corporate purposes.

The Utility also received cash contributions of $885 million from PG&E Corporation during 2012 to ensure that the Utility had adequate capital to maintain the 52% common equity ratio authorized by the CPUC.

PG&E Corporation

In November 2011, PG&E Corporation entered into an Equity Distribution Agreement providing for the sale of PG&E Corporation common stock having an aggregate gross offering price of up to $400 million. Sales of the shares are made by means of ordinary brokers' transactions on the New York Stock Exchange, or in such other transactions as agreed upon by PG&E Corporation and the sales agents and in conformance with applicable securities laws. For 2012, PG&E Corporation sold 5,446,760 shares of its common stock under the Equity Distribution Agreement for cash proceeds of $234 million, net of fees and commissions paid of $2 million. The proceeds from these sales were used for general corporate purposes, including the infusion of equity into the Utility. As of December 31, 2012, PG&E Corporation had the ability to issue an additional $64 million of its common stock under the November Equity Distribution Agreement.

In March 2012, PG&E Corporation sold 5,900,000 shares of its common stock in an underwritten public offering for cash proceeds of $254 million, net of fees and commissions. In addition, during 2012, PG&E Corporation issued 6,803,101 shares of common stock under its 401(k) plan, its Dividend Reinvestment and Stock Purchase Plan, and its share-based compensation plans, generating $263 million of cash.

Future Financing Needs

The amount and timing of the Utility's future debt financings and equity needs will depend on various factors, including:

- the amount of cash internally generated through normal business operations;
- the timing and amount of forecasted capital expenditures;
- the timing and amount of payments made to third parties in connection with the San Bruno accident, and the timing and amount of related insurance recoveries (see "Natural Gas Matters" below);
- the timing and amount of penalties imposed on the Utility in connection with the pending investigations and other potential enforcement matters related to the San Bruno accident and the Utility's natural gas operations (see "Natural Gas Matters" below);
- the timing and amount of pipeline-related expenses and other expenses to improve the safety and reliability of the Utility's electric and natural gas operations that are not recoverable through rates (see "Operating and Maintenance" above);
- the timing of the resolution of the Chapter 11 disputed claims and the amount of interest on these claims that the Utility will be required to pay (see Note 13 of the Notes to the Consolidated Financial Statements);
- the amount of future tax payments; and
- the conditions in the capital markets, and other factors.

PG&E Corporation contributes equity to the Utility as needed to maintain the Utility's CPUC-authorized capital structure. In December 2012, the CPUC issued a final decision authorizing the Utility to maintain a capital structure consisting of 52% equity, 47% long-term debt and 1% preferred stock, beginning on January 1, 2013. The decision also reduced the authorized ROE from 11.35% to 10.40%. (See the "2013 Cost of Capital Proceeding" discussion in "Regulatory Matters" below.) The Utility's future equity needs will continue to be affected by costs that are not recoverable through rates, including costs related to natural gas matters. Further, given the Utility's significant ongoing capital expenditures, it will continue to need equity contributions from PG&E Corporation to maintain its authorized capital structure.

PG&E Corporation's equity contributions to the Utility are funded primarily through common stock issuances. PG&E Corporation also may use draws under its revolving credit facility to occasionally fund equity contributions on an interim basis. Additional common stock issued by PG&E Corporation in the future to fund further equity contributions to the Utility could have a material dilutive effect on PG&E Corporation's earnings per common share.

Dividends

The Board of Directors of PG&E Corporation and the Utility have each adopted a common stock dividend policy that is designed to meet the following three objectives:

- *Comparability:* Pay a dividend competitive with the securities of comparable companies based on payout ratio (the proportion of earnings paid out as dividends) and, with respect to PG&E Corporation, yield (i.e., dividend divided by share price);
- *Flexibility:* Allow sufficient cash to pay a dividend and to fund investments while avoiding having to issue new equity unless PG&E Corporation's or the Utility's capital expenditure requirements are growing rapidly and PG&E Corporation or the Utility can issue equity at reasonable cost and terms; and
- *Sustainability:* Avoid reduction or suspension of the dividend despite fluctuations in financial performance except in extreme and unforeseen circumstances.

Each Board of Directors retains authority to change the common stock dividend rate at any time, especially if unexpected events occur that would change its view as to the prudent level of cash conservation. No dividend is payable unless and until declared by the applicable Board of Directors. In addition, before declaring a dividend, the CPUC requires that the PG&E Corporation Board of Directors give first priority to the Utility's capital requirements, 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. The Boards of Directors must also consider the CPUC requirement that the Utility maintain, on average, its CPUC-authorized capital structure including a 52% equity component.

The Board of Directors of PG&E Corporation declared dividends of $0.455 per share for each of the quarters of 2012, for an annual dividend of $1.82 per share.

The following table summarizes PG&E Corporation's and the Utility's dividends paid:

(in millions)	2012	2011	2010
PG&E Corporation:			
Common stock dividends paid	$ 746	$ 704	$ 662
Common stock dividends reinvested in Dividend Reinvestment and Stock Purchase Plan	22	24	18
Utility:			
Common stock dividends paid	$ 716	$ 716	$ 716
Preferred stock dividends paid	14	14	14

In December 2012, the Board of Directors of PG&E Corporation declared quarterly dividends of $0.455 per share, totaling $196 million, of which $191 million was paid on January 15, 2013 to shareholders of record on December 31, 2012. The remaining $5 million was reinvested under the Dividend Reinvestment and Stock Purchase Plan.

In December 2012, the Board of Directors of the Utility declared dividends on its outstanding series of preferred stock, payable on February 15, 2013, to shareholders of record on January 31, 2013.

As the Utility focuses on improving the safety and reliability of its natural gas and electric operations, and subject to the outcome of the matters described under "Natural Gas Matters" below, PG&E Corporation expects that its Board will continue to maintain the current quarterly common stock dividend.

Utility

Operating Activities

The Utility's cash flows from operating activities primarily consist of receipts from customers less payments of operating expenses, other than expenses such as depreciation that do not require the use of cash.

The Utility's cash flows from operating activities for 2012, 2011, and 2010 were as follows:

(in millions)	**2012**	**2011**	**2010**
Net income	$ 811	$ 845	$ 1,121
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	2,272	2,215	1,905
Allowance for equity funds used during construction	(107)	(87)	(110)
Deferred income taxes and tax credits, net	684	582	762
Disallowed capital expenditures	353	—	36
Other	236	289	221
Effect of changes in operating assets and liabilities:			
Accounts receivable	(40)	(227)	(105)
Inventories	(24)	(63)	(43)
Accounts payable	(26)	51	109
Income taxes receivable/payable	(50)	(192)	(58)
Other current assets and liabilities	272	36	123
Regulatory assets, liabilities, and balancing accounts, net	291	(100)	(394)
Other noncurrent assets and liabilities	256	414	(331)
Net cash provided by operating activities	**$ 4,928**	**$ 3,763**	**$ 3,236**

During 2012, net cash provided by operating activities increased by $1,165 million compared to 2011. This increase was primarily due to a decrease of $352 million in net collateral paid by the Utility related to price risk management activities, a $353 million disallowance for capital expenditures incurred in connection with its pipeline safety enhancement plan, a receipt of $250 million, net of legal fees, from the U.S. Treasury related to spent nuclear fuel costs, and a decrease in tax payments of $224 million. The remaining changes in cash flows from operating activities consisted of fluctuations in activities within the normal course of business such as the timing and amount of customer billings and collections.

During 2011, net cash provided by operating activities increased $527 million compared to 2010 primarily due to a decrease of $214 million in net collateral paid by the Utility related to price risk management activities. This increase also reflects a decrease in tax payments of $121 million in 2011 compared to 2010. The remaining changes in cash flows from operating activities consisted of fluctuations in activities within the normal course of business such as collateral and the timing and amount of customer billings and collections.

Future cash flow from operating activities will be affected by the timing and amount of payments to be made to third parties in connection with the San Bruno accident, including related insurance recoveries; the timing and amount of penalties that may be assessed, as well as any remedial actions the CPUC may order the Utility to perform; and the anticipated higher operating and maintenance costs associated with the Utility's natural gas and electric operations, among other factors. (See "Operating and Maintenance" above and "Natural Gas Matters" below.)

Investing Activities

The Utility's investing activities primarily consist of construction of new and replacement facilities necessary to deliver safe and reliable electricity and natural gas services to its customers. The amount and timing of the Utility's capital expenditures is affected by many factors such as the occurrence of storms and other events causing outages or damages to the Utility's infrastructure. Cash used in investing activities also includes the proceeds from sales of nuclear decommissioning trust investments which are largely offset by the amount of cash used to purchase new nuclear decommissioning trust investments. The funds in the decommissioning trusts, along with accumulated earnings, are used exclusively for decommissioning and dismantling the Utility's nuclear generation facilities.

The Utility's cash flows from investing activities for 2012, 2011, and 2010 were as follows:

(in millions)	2012	2011	2010
Capital expenditures	$ (4,624)	$ (4,038)	$ (3,802)
Decrease in restricted cash	50	200	66
Proceeds from sales and maturities of nuclear decommissioning trust investments	1,133	1,928	1,405
Purchases of nuclear decommissioning trust investments	(1,189)	(1,963)	(1,456)
Other	16	14	19
Net cash used in investing activities	**$ (4,614)**	**$ (3,859)**	**$ (3,768)**

Net cash used in investing activities increased by $755 million in 2012 compared to 2011. This increase was primarily due to an increase of $586 million in capital expenditures and a reduction in restricted cash released for resolved Chapter 11 disputed claims of $150 million.

Net cash used in investing activities increased by $91 million in 2011 compared to 2010, primarily due to an increase in capital expenditures of $236 million as compared to 2010. This increase was partially offset by a decrease of $134 million in restricted cash that was primarily due to releases from escrow for resolved Chapter 11 disputed claims in 2011, with few similar releases in 2010.

Future cash flows used in investing activities are largely dependent on the timing and amount of capital expenditures. (See "Capital Expenditures" below for further discussion of expected spending and significant capital projects.)

Financing Activities

The Utility's cash flows from financing activities for 2012, 2011, and 2010 were as follows:

(in millions)	2012	2011	2010
Borrowings under revolving credit facilities	$ —	$ 208	$ 400
Repayments under revolving credit facilities	—	(208)	(400)
Net issuances (repayments) of commercial paper, net of discount of $3 in 2012, $4 in 2011, and $3 in 2010	(1,021)	782	267
Proceeds from issuance of short-term debt, net of issuance costs of $1 in 2011 and 2010	—	250	249
Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $13 in 2012, $8 in 2011, and $23 in 2010	1,137	792	1,327
Short-term debt matured	(250)	(250)	(500)
Long-term debt matured or repurchased	(50)	(700)	(95)
Energy recovery bonds matured	(423)	(404)	(386)
Preferred stock dividends paid	(14)	(14)	(14)
Common stock dividends paid	(716)	(716)	(716)
Equity contribution	885	555	190
Other	28	54	(73)
Net cash provided by (used in) financing activities	**$ (424)**	**$ 349**	**$ 249**

In 2012, net cash provided by financing activities decreased by $773 million compared to the same period in 2011. In 2011, net cash provided by financing activities increased by $100 million compared to 2010. Cash provided by or used in financing activities is driven by the Utility's financing needs, which depend on the level of cash provided by or used in operating activities and the level of cash provided by or used in investing activities. The Utility generally utilizes long-term senior unsecured debt issuances and equity contributions from PG&E Corporation to maintain its CPUC-authorized capital structure, and relies on short-term debt to fund temporary financing needs.

PG&E Corporation

As of December 31, 2012, PG&E Corporation's affiliates had entered into four tax equity agreements with two privately held companies to fund residential and commercial retail solar energy installations. Under these agreements, PG&E Corporation has agreed to provide lease payments and investment contributions of up to $396 million to these companies in exchange for the right to receive benefits from local rebates, federal grants, and a share of the customer payments made to these companies. PG&E Corporation's financial exposure from these arrangements is generally limited to its lease payments and investment contributions to these companies. As of December 31, 2012, PG&E Corporation had made total payments of $361 million under these tax equity agreements and received $228 million in benefits and customer payments. Lease payments, investment contributions, benefits, and customer payments received are included in cash flows from operating and investing activities within the Consolidated Statements of Cash Flows.

In addition to the investments above, PG&E Corporation had the following material cash flows on a stand-alone basis for the years ended December 31, 2012, 2011, and 2010: dividend payments, common stock issuances, borrowings and repayments under the revolving credit facility in 2012 and 2011, and transactions between PG&E Corporation and the Utility.

CONTRACTUAL COMMITMENTS

The following table provides information about PG&E Corporation's and the Utility's contractual commitments at December 31, 2012:

	Payment due by period				
(in millions)	**Less Than 1 Year**	**1 - 3 Years**	**3 - 5 Years**	**More Than 5 Years**	**Total**
Contractual Commitments:					
Utility					
Long-term debt[1]:					
Fixed rate obligations	$ 1,035	$ 2,148	$ 1,824	$ 17,305	$ 22,312
Variable rate obligations	2	8	941	153	1,104
Purchase obligations[2]:					
Power purchase agreements:					
Qualifying facilities ("QF")	892	1,641	1,108	2,238	5,879
Renewable Energy (other than QF)	1,356	3,881	4,107	30,958	40,302
Other power purchase agreements	846	1,326	1,223	3,322	6,717
Natural gas supply, transportation, and storage	707	400	260	865	2,232
Nuclear fuel agreements	113	322	295	878	1,608
Pension and other benefits[3]	455	796	796	398[6]	2,445
Capital lease obligations[4]	35	51	40	20	146
Operating leases[4]	42	69	55	206	372
Preferred dividends[5]	14	28	28	—	70
PG&E Corporation					
Long-term debt[1]:					
Fixed rate obligations	20	355	—	—	375

(1) Includes interest payments over the terms of the debt. Interest is calculated using the applicable interest rate at December 31, 2012 and outstanding principal for each instrument with the terms ending at each instrument's maturity. Variable rate obligations consist of pollution control bonds, due in 2016 and 2026 and related loans and are backed by letters of credit that expire on May 31, 2016. (See Note 4 of the Notes to the Consolidated Financial Statements.)

(2) This table includes power purchase agreements that have been approved by the CPUC and have completed major milestones for construction. (See Note 15 of the Notes to the Consolidated Financial Statements.

(3) PG&E Corporation's and the Utility's funding policy is to contribute tax-deductible amounts, consistent with applicable regulatory decisions and federal minimum funding requirements. (See Note 12 of the Notes to the Consolidated Financial Statements.)

(4) See Note 15 of the Notes to the Consolidated Financial Statements.

(5) Based on historical performance, it is assumed for purposes of the table above that dividends are payable within a fixed period of five years.

(6) Payments into the pension and other benefits plans are based on annual contribution requirements. As these annual requirements continue indefinitely into the future, the amount reflected represents only 1 year of contributions for the Utility's pension and other benefit plans.

The contractual commitments table above excludes potential commitments associated with the conversion of existing overhead electric facilities to underground electric facilities. At December 31, 2012, the Utility was committed to spending approximately $277 million for these conversions. These funds are conditionally committed depending on the timing of the work, including the schedules of the respective cities, counties, and communication utilities involved. The Utility expects to spend $86 million each year in connection with these projects. Consistent with past practice, the Utility expects that these capital expenditures will be included in rate base as each individual project is completed, resulting in the capital expenditures being recoverable from customers.

The contractual commitments table above also excludes potential payments associated with unrecognized tax positions. Due to the uncertainty surrounding tax audits, PG&E Corporation and the Utility cannot make reliable estimates of the amounts and periods of future payments to major tax jurisdictions related to unrecognized tax benefits. Matters relating to tax years that remain subject to examination are discussed in Note 9 of the Notes to the Consolidated Financial Statements.

CAPITAL EXPENDITURES

The Utility makes various capital investments in its electric generation and electric and natural gas transmission and distribution infrastructure to maintain and improve system reliability, safety, and customer service; to extend the life of or replace existing infrastructure; and to add new infrastructure to meet growth. Most of the Utility's revenue requirements to recover forecasted capital expenditures are authorized in the GRC, TO, and GT&S rate cases. (See "2014 General Rate Case" below.) The Utility also collects additional revenue requirements to recover capital expenditures related to projects that have been specifically authorized by the CPUC, such as new power plants, gas or electric distribution projects, and the SmartMeter™ advanced metering infrastructure.

The Utility's capital expenditures for property, plant, and equipment totaled $4.8 billion in 2012, $4.2 billion in 2011, and $3.9 billion in 2010. The Utility forecasts that capital expenditures will total approximately $5.1 billion in 2013, including expenditures related to its pipeline safety enhancement plan.

Natural Gas Pipeline Safety Enhancement Plan

On December 28, 2012, the CPUC issued a decision that approved the Utility's proposed pipeline safety enhancement plan (filed in August 2011) but disallowed the Utility's request for rate recovery of a significant portion of plan-related costs the Utility forecasted it would incur over the first phase of the plan (2011 through 2014). The CPUC decision limited the Utility's recovery of capital expenditures to $1.0 billion of the total $1.4 billion requested. As a result, the Utility recorded a charge of $353 million in 2012 for disallowed capital expenditures. (See "Natural Gas Matters—CPUC Gas Safety Rulemaking Proceeding" below.)

Oakley Generation Facility

On December 20, 2012, the CPUC approved an amended purchase and sale agreement between the Utility and a third-party developer that provides for the construction of a 586-megawatt natural gas-fired facility in Oakley, California. The CPUC authorized the Utility to recover the purchase price through rates. During January 2013, several parties filed applications for rehearing of the CPUC decision. PG&E Corporation and Utility are uncertain whether the CPUC will modify its decision based on these applications.

NATURAL GAS MATTERS

PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows, have continued to be negatively affected by costs the Utility has incurred to improve the safety and reliability of the Utility's natural gas operations, as well as by costs related to the on-going regulatory proceedings, investigations, and civil lawsuits related to the San Bruno accident and the Utility's natural gas operations. Since the San Bruno accident, PG&E

Corporation and the Utility have incurred total cumulative charges to net income of $1.83 billion related to natural gas matters.

(in millions)	2012	2011	2010	Total
Pipeline-related expenses(1)	$ 477	$ 483	$ 63	$ 1,023
Disallowed capital expenditures(1)	353	—	—	353
Accrued penalties(2)	17	200	—	217
Third-party claims(3)	80	155	220	455
Insurance recoveries(3)	(185)	(99)	—	(284)
Contribution to the City of San Bruno(4)	70	—	—	70
Total natural gas matters	**$ 812**	**$ 739**	**$ 283**	**$ 1,834**

(1) See "CPUC Gas Safety Rulemaking Proceeding" below.
(2) See "Pending CPUC Investigations and Enforcement Matters" below.
(3) See "Third-Party Claims" below.
(4) On March 12, 2012, the Utility and the City of San Bruno entered into an agreement under which the Utility contributed $70 million to support the city and the community's recovery efforts.

Pending CPUC Investigations and Enforcement Matters

The CPUC is conducting three investigations of the Utility's natural gas operations that relate to (1) the Utility's safety recordkeeping for its natural gas transmission system, (2) the Utility's operation of its natural gas transmission pipeline system in or near locations of higher population density, and (3) the Utility's pipeline installation, integrity management, recordkeeping and other operational practices, and other events or courses of conduct, that could have led to or contributed to the San Bruno accident. (See Note 15 of the Notes to the Consolidated Financial Statements.) Although the Utility, the CPUC's Safety and Enforcement Division ("SED"), and other parties have engaged in settlement discussions in an effort to reach a stipulated outcome to resolve the investigations, the parties have not reached an agreement. PG&E Corporation and the Utility are uncertain whether or when any stipulated outcome might be reached. Any agreement regarding a stipulated outcome would be subject to CPUC approval.

The CPUC has concluded evidentiary hearings in each of these investigations. The CPUC administrative law judges ("ALJs") who oversee the investigations have adopted a revised procedural schedule, including the dates by which the parties' briefs must be submitted. The ALJs have also permitted the other parties (the City of San Bruno, The Utility Reform Network, and the City and County of San Francisco) to separately address in their opening briefs their allegations against the Utility, if any, in addition to the allegations made by the SED. The ALJs have ordered the SED and other parties to file single coordinated briefs to address potential monetary penalties and remedies (which could include remedial operational or policy measures) for all three investigations by April 26, 2013. After briefing has been completed, the ALJs will issue one or more presiding officer's decisions listing the violations determined to have been committed, the amount of penalties, and any required remedial actions. Based on the revised procedural schedule, one or more presiding officer's decisions will be issued by July 23, 2013. The decisions would become the final decisions of the CPUC thirty days after issuance unless the Utility or another party filed an appeal, or a CPUC commissioner requested review of the decision, within such time. (See "Penalties Conclusion" below.)

Other Potential Enforcement Matters

California gas corporations are required to provide notice to the CPUC of any self-identified or self-corrected violations of certain state and federal regulations related to the safety of natural gas facilities and the corporations' natural gas operating practices. The CPUC has authorized the SED to issue citations and impose penalties based on self-reported violations. In April 2012, the CPUC affirmed a $17 million penalty that had been imposed by the SED based on the Utility's self-report that it failed to conduct periodic leak surveys because it had not included 16 gas distribution maps in its leak survey schedule. (The Utility has paid the penalty and completed all of the missed leak surveys.) As of December 31, 2012, the Utility has submitted 34 self-reports with the CPUC, plus additional follow-up reports. The SED has not yet taken formal action with respect to the Utility's other self-reports. The SED may issue additional citations and impose penalties on the Utility associated with these or future reports that the Utility may file. (See "Penalties Conclusion" below.)

In addition, in July 2012, the Utility reported to the CPUC that it had discovered that its access to some pipelines has been limited by vegetation overgrowth or building structures that encroach upon some of the Utility's gas transmission pipeline rights-of-way. The Utility is undertaking a system-wide effort to identify and remove encroachments from its pipeline rights-of-way over a multi-year period. (See "Operating and Maintenance" above.) PG&E Corporation and the Utility are uncertain how this matter will affect the above investigative proceedings related to natural gas operations, or whether additional proceedings or investigations will be commenced that could result in regulatory orders or the imposition of penalties on the Utility.

Penalties Conclusion

The CPUC can impose penalties of up to $20,000 per day, per violation. (For violations that are considered to have occurred on or after January 1, 2012, the statutory penalty has increased to a maximum of $50,000 per day, per violation.) The CPUC has wide discretion to determine the amount of penalties based on the totality of the circumstances, including such factors as the gravity of the violations; the type of harm caused by the violations and the number of persons affected; and the good faith of the entity charged in attempting to achieve compliance, after notification of a violation. The CPUC is also required to consider the appropriateness of the amount of the penalty to the size of the entity charged. The CPUC has historically exercised this wide discretion in determining penalties. The CPUC's delegation of enforcement authority to the SED allows the SED to use these factors in exercising discretion to determine the number of violations, but the SED is required to impose the maximum statutory penalty for each separate violation that the SED finds.

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. In determining the amount of penalties the ALJs may consider the testimony of financial consultants engaged by the SED and the Utility. The SED's financial consultant prepared a report concluding that PG&E Corporation could raise approximately $2.25 billion through equity issuances, in addition to equity PG&E Corporation had already forecasted it would issue in 2012, to fund CPUC-imposed penalties on the Utility. The Utility's financial consultant disagreed with this financial analysis and asserted that a fine in excess of financial analysts' expectations, which the consultant's report cited as a mean of $477 million, would make financing more difficult and expensive. The ALJs have scheduled a hearing to be held on March 4 and March 5, 2013 to consider the SED's and Utility's testimony. The SED and other parties are scheduled to file briefs to address potential monetary penalties and remedies in all three investigations by April 26, 2013.

PG&E Corporation and the Utility believe it is probable that the Utility will incur penalties of at least $200 million in connection with these pending investigations and potential enforcement matters and have accrued this amount in their consolidated financial statements. PG&E Corporation and the Utility are unable to make a better estimate of probable losses or estimate the range of reasonably possible losses in excess of the amount accrued due to the many variables that could affect the final outcome of these matters and the ultimate amount of penalties imposed on the Utility could be materially higher than the amount accrued. These variables include how the CPUC and the SED will exercise their discretion in calculating the amount of penalties, including how the total number of violations will be counted; how the duration of the violations will be determined; whether the amount of penalties in each investigation will be determined separately or in the aggregate; how the financial resources testimony submitted by the SED and the Utility will be considered; whether the Utility's costs to perform any required remedial actions will be considered; and whether and how the financial impact of non-recoverable costs the Utility has already incurred, and will continue to incur, to improve the safety and reliability of its pipeline system, will be considered. (See "CPUC Gas Safety Rulemaking Proceeding" below.)

These estimates, and the assumptions on which they are based, are subject to change based on many factors, including rulings, orders, or decisions that may be issued by the ALJs; whether the outcome of the investigations is resolved through a fully litigated process or a stipulated outcome that is approved by the CPUC; whether the SED will take additional action with respect to the Utility's self-reports; and whether the CPUC or the SED takes any action with respect to the encroachment matter described above. Future changes in these estimates or the assumptions on which they are based could have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

CPUC Gas Safety Rulemaking Proceeding

The CPUC is conducting a rulemaking proceeding to develop and adopt new safety and reliability regulations for natural gas transmission and distribution pipelines in California and the related ratemaking mechanisms. On December 28, 2012, the CPUC issued a decision that approved most of the Utility's proposed pipeline safety enhancement plan to modernize and upgrade its natural gas transmission system, but disallowed the Utility's request for rate recovery of a significant portion of plan-related costs the Utility forecasted it would incur over the first phase of the plan (2011 through 2014).

In its application filed in August 2011, the Utility forecasted that it would incur total plan-related costs of approximately $2.2 billion, composed of $1.4 billion in capital expenditures and $750 million in expenses. The CPUC decision prohibited the Utility from recovering any expenses incurred before December 20, 2012, the effective date of the decision, and from recovering certain categories of expenses that the Utility forecasts it will incur in 2013 and 2014. The CPUC decision also limits the Utility's recovery of capital expenditures to $1 billion. The Utility will be unable to recover any costs in excess of the adopted capital and expense amounts and the adopted amounts will be reduced by the cost of any plan project not completed and not replaced with a higher priority project. The CPUC also determined that the Utility should not recover in rates 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 may disallow additional costs based on the final results of the Utility's pipeline records search and pipeline pressure validation work, which the Utility expects to complete by May 2013. The Utility is required to update its plan and file an application within 30 days after this work is completed.

The following table compares the Utility's requested expense and capital amounts (based on forecasts included in the August 2011 application) with the amounts authorized by the CPUC:

(in millions)	2011	2012	2013	2014	Total
Expense					
Requested	$ 221[(1)]	$ 231	$ 155	$ 144	$ 751
Authorized	—	3	73	89	165
Difference	$ 221[(1)]	$ 228	$ 82	$ 55	$ 586
Capital					
Requested	$ 69	$ 384	$ 480	$ 500	$ 1,433
Authorized	47	260	348	348	1,003
Difference	$ 22	$ 124	$ 132	$ 152	$ 430

(1) The Utility's August 2011 application did not request recovery of forecast 2011 plan-related expenses of $221 million.

For the year ended December 31, 2012, the Utility incurred total pipeline-related expenses of $477 million, including plan-related expenses of $271 million. As a result of the decision, the Utility also recorded a charge of $353 million for capital expenditures that are forecast to exceed the CPUC's authorized levels or that were specifically disallowed. All plan-related costs for 2013 and 2014 will be charged to net income in the period incurred. Unrecoverable plan-related costs are expected to range from approximately $150 million to $200 million in 2013 and a comparable amount in 2014. The CPUC stated that the Utility's recovery of the amounts authorized in the decision will be subject to refund, noting the possibility that further ratemaking adjustments may be made in the pending CPUC investigations in which the CPUC will address potential penalties to be imposed on the Utility. (See "Pending CPUC Investigations and Enforcement Matters" above.)

The CPUC delegated authority to the SED to oversee all of the Utility's work performed pursuant to the pipeline safety enhancement plan, including the authority to participate in all plan-related activities and review and modify all changes proposed by the Utility. The Utility must submit quarterly compliance reports to the CPUC that will include information about actual cost compared to authorized cost for each work project; the construction status of projects; and changes in scope and prioritization of projects. As a result of the compliance reporting process, the Utility could incur additional non-recoverable costs. The CPUC also ordered the SED to engage consultants to conduct management and financial audits to address safety-related corporate culture and historical spending. (As discussed below, the financial audit of the Utility's natural gas distribution spending will be considered in the 2014 GRC, but the scope and timing of the management audit is still uncertain.) (See "2014 GRC" below.)

On January 28, 2013, several parties filed applications for rehearing of the CPUC's decision. The applications for rehearing state, among other arguments, that the CPUC should have disallowed more of the Utility's costs and that the CPUC should have approved a reduced ROE for capital expenditures made under the plan. Several parties also have filed petitions for modification of the decision. It is uncertain whether or when the CPUC will grant these requests.

The second phase of the Utility's pipeline safety enhancement plan in 2015 will focus on pipeline segments in less populated areas, as well as certain pressure testing and pipeline replacement work that the CPUC deferred from the first phase. The Utility expects to address the scope, timing, and cost recovery of the second phase in late 2013 and request that changes to rates be made effective January 1, 2015.

Criminal Investigation

The U.S. Department of Justice, the California Attorney General's Office, and the San Mateo County District Attorney's Office are conducting an investigation of the San Bruno accident and have indicated that the Utility is a target of the investigation. The Utility is cooperating with the investigation. PG&E Corporation and the Utility are uncertain whether any criminal charges will be brought against either company or any of their current or former employees.

PG&E Corporation and the Utility are unable to estimate the amount (or range of amounts) of reasonably possible losses associated with any civil or criminal penalties that could be imposed on the Utility as a consequence of this investigation.

Third-Party Claims

In addition to the investigations and proceedings discussed above, at December 31, 2012, approximately 140 lawsuits involving third-party claims for personal injury and property damage, including two class action lawsuits, had been filed against PG&E Corporation and the Utility in connection with the San Bruno accident on behalf of approximately 450 plaintiffs. The lawsuits seek compensation for personal injury and property damage, and other relief, including punitive damages. These cases were coordinated and assigned to one judge in the San Mateo County Superior Court. Many of the plaintiffs' claims have been resolved through settlements. The trial of the first group of remaining cases began on January 2, 2013 with pretrial motions and hearings. On January 14, 2013, the court vacated the trial and all pending hearings due to the significant number of cases that have been settled outside of court. The court has urged the parties to settle the remaining cases. As of February 8, 2013, the Utility has entered into settlement agreements to resolve the claims of approximately 140 plaintiffs. It is uncertain whether or when the Utility will be able to resolve the remaining claims through settlement.

At December 31, 2012, the Utility had recorded cumulative charges of $455 million for estimated third-party claims related to the San Bruno accident, including an $80 million charge made during 2012, primarily to reflect settlements and information exchanged by the parties during the settlement and discovery process. The Utility estimates it is reasonably possible that it may incur as much as an additional $145 million for third-party claims, for a total possible loss of $600 million. PG&E Corporation and the Utility are unable to estimate the amount (or range of amounts) of reasonably possible losses associated with punitive damages, if any, related to these matters. The Utility has publicly stated that it is liable for the San Bruno accident and will take financial responsibility to compensate all of the victims for the injuries they suffered as a result of the accident. (See Note 15 to the Consolidated Financial Statements.)

The Utility has recognized cumulative insurance recoveries of $284 million for third-party claims, which included $185 million for 2012 and $99 million for 2011. Although the Utility believes that a significant portion of costs incurred for third-party claims relating to the San Bruno accident will ultimately be recovered through its insurance, it is unable to predict the amount and timing of additional insurance recoveries. (See Note 15 to the Consolidated Financial Statements.)

Class Action Complaint

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. To state their claims, the plaintiffs cited the SED's January 2012 investigative report of the San Bruno accident that alleged, from 1996 to 2010, the Utility spent less on capital expenditures and operations and maintenance expense for its natural gas transmission operations than it recovered in rates, by $95 million and $39 million, respectively. The SED recommended that the Utility should use such amounts to fund future gas transmission expenditures and operations. Plaintiffs allege that PG&E Corporation and the Utility engaged in unfair business practices in violation of Section 17200 of the California Business and Professions Code ("Section 17200") and claim that this violation also constitutes a violation of California Public Utilities Code Section 2106 ("Section 2106"), which provides a private right of action for violations of the California constitution or state laws by public utilities. Plaintiffs seek restitution and disgorgement under Section 17200 and compensatory and punitive damages under Section 2106.

PG&E Corporation and the Utility contest the plaintiffs' allegations. In January 2013, PG&E Corporation and the Utility requested that the court dismiss the complaint on the grounds that the CPUC has exclusive jurisdiction to adjudicate the issues raised by the plaintiffs' allegations. In the alternative, PG&E Corporation and the Utility requested that the court stay the proceeding until the CPUC investigations described above are concluded. The court has set a hearing on the motion for April 26, 2013. Due to the early stage of this proceeding, PG&E Corporation and the Utility are unable to estimate the amount (or range of amounts) of reasonably possible losses that may be incurred in connection with this matter.

Other Pending Lawsuits and Claim

In October 2010, a purported shareholder derivative lawsuit was filed in San Mateo Superior Court following the San Bruno accident to seek recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims, relating to the Utility's natural gas business. The judge has ordered that proceedings in the derivative lawsuit be delayed until further order of the court. On February 7, 2013, another purported shareholder derivative lawsuit was filed in U.S. District Court for the Northern District of California to seek recovery on behalf of PG&E Corporation for alleged breaches of fiduciary duty by officers and directors, among other claims.

In February 2011, the Board of Directors of PG&E Corporation authorized PG&E Corporation to reject a demand made by another shareholder that the Board of Directors (1) institute an independent investigation of the San Bruno accident and related alleged safety issues; (2) seek recovery of all costs associated with such issues through legal proceedings against those determined to be responsible, including Board of Directors members, officers, other employees, and third parties; and (3) adopt corporate governance initiatives and safety programs. The Board of Directors also reserved the right to commence further investigation or litigation regarding the San Bruno accident if the Board of Directors deems such investigation or litigation appropriate.

REGULATORY MATTERS

The Utility is subject to substantial regulation by the CPUC, the FERC, the NRC and other federal and state regulatory agencies. The resolutions of these and other proceedings may affect PG&E Corporation's and the Utility's results of operations and financial condition.

2013 Cost of Capital Proceeding

On December 20, 2012, the CPUC issued a final decision authorizing the Utility to maintain a capital structure consisting of 52% equity, 47% long-term debt, and 1% preferred stock, beginning on January 1, 2013. This capital structure applies to the Utility's electric generation, electric and natural gas distribution, and natural gas transmission and storage rate base. In addition, the CPUC authorized the Utility to earn a rate of return on each component of the capital structure, including a ROE of 10.40%, compared to the 11% ROE requested by the Utility. The following table compares the 2012 and 2013 authorized capital structure and rates of return:

	2012 Authorized			2013 Authorized		
	Cost	Capital Structure	Weighted Cost	Cost	Capital Structure	Weighted Cost
Long-term debt	6.05%	46%	2.78%	5.52%	47%	2.59%
Preferred stock	5.68%	2%	0.11%	5.60%	1%	0.06%
Return on common equity	11.35%	52%	5.90%	10.40%	52%	5.41%
Overall Rate of Return			8.79%			8.06%

The Utility estimates that the 2013 revenue requirement associated with the authorized cost of capital will be approximately $235 million less than the currently authorized revenue requirement. Approximately $165 million of this estimated decrease is attributable to the lower authorized ROE. Changes to the Utility's revenue requirement became effective on January 1, 2013.

The Utility and other parties have submitted a joint stipulation to the CPUC in which the parties agreed to continue the annual cost of capital adjustment mechanism that had been in effect since 2008, and to file the next full cost of capital applications in April 2015 for the 2016 test year. Under the mechanism as proposed to be continued, the Utility's ROE would be 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 1st 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 CPUC is scheduled to issue a proposed decision by March 15, 2013 with a final decision by April 18, 2013.

2014 General Rate Case

On November 15, 2012, the Utility filed its 2014 GRC application with the CPUC. In the Utility's 2014 GRC, the CPUC will determine the annual amount of revenue requirements that the Utility will be authorized to collect from customers from 2014 through 2016 to recover its anticipated costs for electric and natural gas distribution and electric generation operations and to provide the Utility an opportunity to earn its authorized rate of return.

The Utility has requested that the CPUC increase the Utility's authorized base revenues for 2014 by a total of $1.28 billion over the comparable base revenues for 2013 that were previously authorized by the CPUC. Over the 2014-2016 GRC period, the Utility plans to make annual additional capital investments of nearly $4 billion in electric and natural gas distribution and electric generation infrastructure. The Utility forecasts that its 2014 weighted average rate base for the portion of the Utility's business reviewed in the GRC will be $21.4 billion.

The following table compares the requested 2014 revenue requirement amounts by line of business with the comparable revenue requirements currently authorized for 2013:

(in millions) Line of Business:	Amounts requested in the GRC application	Amounts currently authorized for 2013	Increase compared to currently authorized amounts
Electric distribution	$ 4,355	$ 3,768	$ 587
Gas distribution	1,810	1,324	486
Electric generation	1,946	1,737	209
Total revenue requirements	**$ 8,111**	**$ 6,829**	**$ 1,282**

The Utility's 2014 forecast for gas distribution operations includes increased costs to replace 180 miles of distribution line per year (compared to 30 miles currently), use new leak detection technologies and survey the entire system more frequently, remotely monitor and control a significant number of valves, implement an asset management system to provide detailed, readily accessible information about the gas distribution system, and reduce response times for customer gas odor reports. The Utility's forecast for electric distribution operations includes increased costs to upgrade and replace assets to improve safety and reduce outages, use infrared technology to identify and correct equipment issues, install more automation to limit the impact and duration of outages, mitigate wildfire risk, increase system capacity to meet new customer demand, and enhance asset records management and integrate it with key systems. The Utility's forecast for electric generation includes increased costs to operate the Utility's hydroelectric system (including costs related to the Helms pumped storage facility and costs associated with operating licenses issued by the FERC), comply with new requirements adopted by the NRC applicable to the Utility's Diablo Canyon nuclear power plant, and operate and maintain the Utility's fossil fuel-fired and other generating facilities. In addition, the Utility's forecast includes increased costs to improve service at the Utility's local offices and customer contact centers and to improve the service provided by field account representatives to small and mid-sized business customers.

In its application, the Utility has requested that the CPUC establish new balancing accounts to allow the Utility to recover costs associated with gas leak survey and repair work, major emergencies, and new regulatory requirements related to nuclear operations and hydroelectric relicensing, because these costs are subject to a high degree of uncertainty. The Utility also requested that the CPUC establish a ratemaking mechanism that would increase the Utility's authorized revenues in 2015 and 2016, primarily to reflect increases in rate base due to capital investments in infrastructure and, to a lesser extent, anticipated increases in wages and other expenses. The Utility also has requested that revenue requirements be adjusted to reflect certain externally driven changes in the Utility's costs, such as changes in franchise fees. The Utility estimates that this mechanism would result in increases in revenue of $492 million in 2015 and an additional $504 million in 2016.

Independent consultants engaged by the SED are reviewing and evaluating certain operational plans underlying the Utility's 2014 cost forecast to ensure that safety and security concerns have been addressed and that the plans properly incorporate risk assessments and mitigation measures. The SED has also engaged independent consultants to conduct a financial audit of the Utility's gas distribution system, which will examine the Utility's authorized and budgeted capital investments and operation and maintenance expenditures for its last two authorized GRC cycles. The SED reports on the results of the consultants' evaluations and financial audit are due May 31, 2013. The Utility and other parties will be able to respond to the reports.

According to the CPUC's current procedural schedule for the proceeding, which may be subject to change in the future, the CPUC's Division of Ratepayer Advocates ("DRA") is scheduled to serve its report on the Utility's application by May 3, 2013. Additional testimony from other parties must be submitted by May 17, 2013. The schedule contemplates evidentiary hearings to be held this summer, followed by a proposed decision to be released in November 2013 and a final CPUC decision to be issued in December 2013. If the decision is delayed, the Utility will, consistent with CPUC practice in prior GRCs, request that the CPUC issue an order directing that the authorized revenue requirement changes be effective January 1, 2014, even if the decision is issued after that date.

FERC Transmission Owner Rate Case

On September 28, 2012, the Utility filed an application with the FERC to increase the Utility's retail and wholesale electric transmission customer rates that have been in effect since March 1, 2011. The proposed rate changes will become effective on May 1, 2013, subject to refund following the FERC's issuance of a final decision. The most significant factors driving the requested increase are the Utility's continuing needs to replace and modernize aging electric transmission infrastructure; to interconnect new electric generation, including renewable resources; and to accommodate the magnitude and location of forecasted electric load growth in California. The Utility forecasts that it will make investments of $783 million in 2012 and an additional $837 million in 2013 in various capital projects, including projects to add transmission capacity, expand automation technology, improve overall system reliability, and maintain and replace equipment at substations. The proposed rate base in 2013 is forecast to be $4.5 billion compared to $3.6 billion in 2011. The operations and maintenance costs associated with this request are forecast to be approximately $191 million in 2013, compared to $152 million in 2011.

Compared to present rates, the Utility estimated that revenues would increase by $254 million based on the Utility's requested ROE of 11.5%, for total 2013 electric transmission revenues of $1.2 billion. On November 29, 2012, the FERC issued an order that accepted the Utility's application but directed the Utility to reduce its proposed revenue requirement and rates to reflect the median ROE of a comparative group of other utilities. In response to the FERC's order, on December 21, 2012, the Utility revised its requested revenue requirements and rates to reflect a 9.1% ROE. Based on the reduced ROE, the Utility estimates that revenues would increase by approximately $158 million, for total annual electric transmission revenues of $1.1 billion beginning on May 1, 2013. On December 21, 2012, the Utility also filed a request for rehearing of the FERC's order. It is uncertain when the FERC will act on the request for rehearing. The ultimate resolution of revenue requirements and rates will be addressed through hearings and settlement procedures.

Energy Efficiency Programs and Incentive Ratemaking

On December 20, 2012, the CPUC approved a new 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 CPUC awarded the Utility $21 million for the successful implementation of the Utility's 2010 energy efficiency programs. The CPUC decision also established the process that is expected to apply to incentive claims for program years 2011 and 2012. After the CPUC completes its audit of the utilities' 2011 program expenditures, the utilities must file their incentive claims in the third quarter of 2013 for approval by the CPUC in the fourth quarter of 2013. Similarly, 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.

Diablo Canyon Nuclear Power Plant

In March 2012, the NRC issued several orders to the owners of all U.S. operating nuclear reactors to implement the highest-priority recommendations issued by the NRC's task force to incorporate the lessons learned from the March 2011 earthquake and tsunami that caused significant damage to the Fukushima-Dai-ichi nuclear facilities in Japan. Among other directives, the NRC requested nuclear power plant owners to provide additional information about seismic and flooding hazards and emergency preparedness. In response to the orders, the utilities are required to re-evaluate the models used to determine compliance with the license conditions relating to seismic and flooding design. Each nuclear power plant owner will be required to be in full compliance with the NRC orders within two refueling outages or by December 31, 2016, whichever comes first. The Utility has already provided the initially requested information to the NRC and will continue to respond to the NRC orders as required. After reviewing the information submitted by the Utility and other nuclear power plant owners, the NRC may issue further orders which may include facility-specific orders. The Utility will incur costs to comply with Fukushima related NRC orders. The Utility has requested that the CPUC allow the Utility to recover costs incurred in 2014 through 2016 to comply with NRC orders through rates to be authorized by the CPUC in the Utility's 2014 GRC.

The Utility also has filed an application at the NRC to renew the operating licenses for the two operating units at Diablo Canyon which expire in 2024 and 2025. In May 2011, after the Fukushima-Dai-ichi event, the NRC granted the Utility's request to delay processing the Utility's application until certain advanced seismic studies were completed by the Utility. When the Utility began the studies in 2010, it was anticipated that the studies would be completed in 2013 or 2014, depending upon whether required permits were timely obtained from environmental and local government agencies. In November 2012, the California Coastal Commission denied the Utility's request for permits to conduct off-shore three-dimensional high-energy seismic studies, in part, based on the finding that, because the studies were not necessary for NRC compliance, the potential environmental effects did not outweigh the risks. The Utility has completed the data collection phases for the on-shore advanced seismic studies as well as other off-shore low-energy seismic studies. The Utility is assessing whether it has sufficient seismic data without conducting high energy off-shore studies or if other studies are needed. Depending on the outcome of the Utility's assessment, it is uncertain when the Utility would request the NRC to resume the relicensing proceeding. In order to receive renewed operating licenses, the Utility also must undergo a consistency review by the California Coastal Commission. The disposition of the Utility's relicensing application also will be affected by the terms and timing of the NRC's "waste confidence" decision regarding the environmental impacts of the storage of spent nuclear fuel which is not expected to be issued before September 2014. The NRC has stated that it will not take action in licensing or re-licensing proceedings until it issues a new "waste confidence decision." (See "Risk Factors" below.)

Finally, the CPUC is also considering the Utility's application to recover estimated costs to decommission the Utility's nuclear facilities at Diablo Canyon and the retired nuclear facility located at the Utility's Humboldt Bay Generation Station. 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. (See the discussion of the 2012 Nuclear Decommissioning Cost Triennal Proceeding in Note 2 of the Notes to the Consolidated Financial Statements.)

Other Matters

Electric Distribution Facilities

The Utility conducted a system-wide review of its patrol and inspection records for underground and overhead electric distribution facilities after the Utility reported to the CPUC in July 2012 that some of the Utility's facilities were not patrolled and/or inspected at the periodic intervals required by the CPUC's rules. The Utility concluded a system-wide review and found that approximately 0.4% of its total electric distribution facilities had not been patrolled and/or inspected at the intervals required by CPUC rules. The Utility has submitted the results of its review to the SED and has completed the patrols and inspections of all such facilities.

In October 2012, the Utility also reported to the CPUC that it planned to re-inspect electric distribution underground and overhead facilities that had been identified as inspected by a contractor after a review determined that the inspection practices used by some of the contractor's employees did not meet the Utility's standards. The re-inspections have been completed.

PG&E Corporation and the Utility are uncertain how the above matters will affect the other regulatory proceedings and current investigations involving the Utility, or whether additional proceedings or investigations will be commenced that could result in regulatory orders or the imposition of penalties on the Utility.

Residential Rate Design

In June 2012, the CPUC opened a rulemaking proceeding to examine electric rate design for residential customers among California's electric utilities and consider regulatory and legislative changes that may be needed to the current rate structure. PG&E Corporation and the Utility are uncertain how the outcome of this rulemaking proceeding will affect the Utility's future electric rate structure.

ENVIRONMENTAL MATTERS

The Utility's operations are subject to extensive federal, state, and local laws and permits relating to the protection of the environment and the safety and health of the Utility's personnel and the public. (See "Risk Factors" below.) These laws and requirements relate to a broad range of the Utility's activities, including the remediation of hazardous wastes; the reporting and reduction of carbon dioxide and other GHG emissions; the discharge of pollutants into the air, water, and soil; and the transportation, handling, storage, and disposal of spent nuclear fuel.

Remediation

The Utility has been, and may be, required to pay for environmental remediation costs at sites where it is identified as a potentially responsible party under federal and state environmental laws. These sites include former manufactured gas plant ("MGP") sites, current and former power plant sites, former gas gathering and gas storage sites, sites where natural gas compressor stations are located, current and former substations, service center and general construction yard sites, and sites currently and formerly used by the Utility for the storage, recycling, or disposal of 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. (See Note 15 of the Notes to the Consolidated Financial Statements.)

The Utility is legally responsible for remediating groundwater contamination caused by hexavalent chromium used in the past at the Utility's natural gas compressor sites. The Utility is also required to take measures to abate the effects of the contamination on the environment. At the Hinkley natural gas compressor site, the Utility's remediation and abatement efforts are subject to the regulatory authority of the California Regional Water Quality Control Board, Lahontan Region ("Regional Board"). The Regional Board has issued several orders directing the Utility to implement interim remedial measures to reduce the mass of the underground plume of hexavalent chromium, monitor and control movement of the plume, and provide replacement water to affected residents.

The Utility submitted its proposed final remediation plan to the Regional Board in September 2011 recommending a combination of remedial methods to clean up groundwater contamination, including using pumped groundwater from extraction wells to irrigate agricultural land and in-situ treatment of the contaminated water. In August 2012, the Regional Board issued a draft environmental impact report ("EIR") that evaluated the Utility's proposed methods and the potential environmental impacts. The Utility expects that the Regional Board will consider certification of the final EIR in the second quarter of 2013. Following certification of the EIR, the Regional Board is expected to issue the final cleanup standards.

The Regional Board ordered the Utility in October 2011 to provide an interim and permanent replacement water system for resident households located near the chromium plume that have domestic wells containing hexavalent chromium in concentrations greater than 0.02 parts per billion. The Utility filed a petition with the California State Water Resources Control Board ("California Water Board") to contest certain provisions of the order. In June 2012, the Regional Board issued an amended order to allow the Utility to implement a whole house water replacement program for resident households located near the chromium plume boundary. Eligible residents may decide whether to accept a replacement water supply or have the Utility purchase their properties, or alternatively not participate in the program. As of January 31, 2013, approximately 350 residential households are covered by the program and the majority have opted to accept the Utility's offer to purchase their properties. The Utility is required to complete implementation of the whole house water replacement systems by August 31, 2013. The Utility will maintain and operate the whole house replacement systems for five years or until the State of California has adopted a drinking water standard specifically for hexavalent chromium at which time the program will be evaluated.

At December 31, 2012 and 2011, $226 million and $149 million, respectively, were accrued in PG&E Corporation's and the Utility's Consolidated Balance Sheets for estimated undiscounted future remediation costs associated with the Hinkley site. The increase primarily reflects the Utility's best estimate of costs associated with the developments described above. Remediation costs for the Hinkley natural gas compressor site are not recovered from customers through rates. Future costs will depend on many factors, including the Regional Board's certification of the final EIR, the levels of hexavalent chromium the Utility is required to use as the standard for remediation, the Utility's required time frame for remediation, and adoption of a final drinking water standard currently under development by the State of California, as mentioned above. As more information becomes known regarding these factors, these estimates and the assumptions on which they are based regarding the amount of liability incurred may be subject to further changes. Future changes in estimates or assumptions may have a material impact on PG&E Corporation's and the Utility's future financial condition, results of operations, and cash flows.

Climate Change

A report issued in 2012 by the U.S. Environmental Protection Agency ("EPA") entitled, "Climate Change Indicators in the United States, 2012" states that the increase of GHG emissions in the atmosphere is changing the fundamental measures of climate in the United States, including rising temperatures, shifting snow and rainfall patterns, and more extreme climate events. (See "Risk Factors" below.) Although no comprehensive federal legislation has been enacted to address the reduction of GHG emissions, the California legislature has taken action to address climate change.

GHG Cap-and-Trade

The California Global Warming Solutions Act of 2006 (also known as California Assembly Bill 32 or AB 32) requires the gradual reduction of state-wide GHG emissions to the 1990 level by 2020. The California Air Resources Board ("CARB") is the state agency charged with monitoring GHG levels and adopting regulations to implement and enforce AB 32. The CARB has approved various regulations, including regulations that established a state-wide, comprehensive "cap-and-trade" program that sets a gradually declining limit (or "cap") on the amount of GHGs that may be emitted by the major sources of GHG emissions each year. 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 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. Emitters may meet up to 8% of their compliance obligation through the purchase of "offset credits" which represent GHG emissions abatement achieved in sectors that are not subject to the cap.

Each year the CARB will issue emission allowances (i.e., the rights to emit GHGs) equal to the amount of GHG emissions allowed for that year. Emitters (also known as covered entities) are required to obtain and surrender allowances equal to the amount of their GHG emissions within a particular compliance period. Emitters can obtain allowances from the CARB at quarterly auctions held by the CARB or from third parties or exchanges on the secondary market for trading GHG allowances. The CARB's first quarterly auction was held on November 14, 2012.

Also, during each year of the program, the CARB will allocate 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 allowances for auction by the CARB. The CPUC has ordered the utilities to allocate their auction revenues, including accrued interest, among certain classes of their electricity distribution customers in accordance with existing state law. Although the CPUC had previously authorized the utilities to recover their GHG compliance costs through rates, the CPUC decided that the recovery of GHG compliance costs should be deferred until the CPUC adopted a final auction revenue allocation methodology. Until a final methodology is adopted, the utilities have been ordered to track GHG costs and auction revenues for future rate recovery. (See Note 3 of the Notes to the Consolidated Financial Statements.) The CARB has not yet decided whether and to what extent allowances will be freely allocated to regulated gas utilities for the benefit of their natural gas customers starting in the second compliance period beginning in 2015.

The Utility expects all costs and revenues associated with GHG cap-and-trade to be passed through to customers.

Renewable Energy Resources

California's Renewables Portfolio Standard ("RPS") program increases the amount of renewable energy that load-serving entities, such as the Utility, must deliver to their customers from at least 20% of their total retail sales, as required by the prior law, to 33% of their total retail sales. The RPS program, which became effective in December 2011, established compliance periods: 2011 through 2013, 2014 through 2016, 2017 through 2020, and 2021 and thereafter. The RPS compliance requirement that must be met for each of these compliance periods will gradually increase through 2020 and will be determined on an annual basis thereafter. In June 2012, the CPUC adopted rules for transitioning between the prior 20% RPS program and the 33% RPS program, applying excess procurement quantities across compliance periods, using procurement from short-term contracts to meet compliance requirements, and reporting annual RPS compliance to the CPUC.

The Utility has made substantial financial commitments under third-party renewable energy contracts to meet RPS procurement quantity requirements. (See Note 15 of the Notes to the Consolidated Financial Statements.) The Utility currently forecasts that it will comply with its procurement requirements. 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.

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. The EPA is required to issue final regulations by July 2013.

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. The committee's assessment is due by October 2013. If the California Water Board does not require the installation of cooling towers at Diablo Canyon, the Utility could incur significant costs to comply with alternative compliance measures or to make payments to support various environmental mitigation projects. The Utility would seek to recover such costs in rates. 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. The Utility's Diablo Canyon operations must be in compliance with the California Water Board's policy by December 31, 2024.

LEGAL MATTERS

In addition to the provisions made for contingencies related to the San Bruno accident, PG&E Corporation's and the Utility's Consolidated Financial Statements also include provisions for claims and lawsuits that have arisen in the ordinary course of business, regulatory proceedings, and other legal matters. (See "Legal and Regulatory Contingencies" in Note 15 of the Notes to the Consolidated Financial Statements.)

OFF-BALANCE SHEET ARRANGEMENTS

PG&E Corporation and the Utility do not have any off-balance sheet arrangements that have had, or are reasonably likely to have, a current or future material effect on their financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures, or capital resources, other than those discussed in Note 2 (PG&E Corporation's tax equity financing agreements) and Note 15 of the Notes to the Consolidated Financial Statements (the Utility's commodity purchase agreements).

RISK MANAGEMENT ACTIVITIES

The Utility and PG&E Corporation, mainly through its ownership of the Utility, are exposed to market risk, which is the risk that changes in market conditions will adversely affect net income or cash flows. PG&E Corporation and the Utility face market risk associated with their operations; their financing arrangements; the marketplace for electricity, natural gas, electric transmission, natural gas transportation, and storage; emissions allowances, other goods and services; and other aspects of their businesses. PG&E Corporation and the Utility categorize market risks as "price risk" and "interest rate risk." The Utility is also exposed to "credit risk," the risk that counterparties fail to perform their contractual obligations.

The Utility actively manages market risk through risk management programs designed to support business objectives, discourage unauthorized risk-taking, reduce commodity cost volatility, and manage cash flows. The Utility uses derivative instruments only for non-trading purposes (i.e., risk mitigation) and not for speculative purposes. The Utility's risk management activities include the use of energy and financial instruments such as forward contracts, futures, swaps, options, and other instruments and agreements, most of which are accounted for as derivative instruments. Some contracts are accounted for as leases.

On July 21, 2010, President Obama signed into law federal financial reform legislation, the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank"). PG&E Corporation and the Utility are implementing programs to comply with the final regulations that have been issued pursuant to Dodd-Frank.

Commodity Price Risk

The Utility is exposed to commodity price risk as a result of its electricity and natural gas procurement activities, including the procurement of natural gas and nuclear fuel necessary for electricity generation and natural gas procurement for core customers. As long as the Utility can conclude that it is probable that its reasonably incurred wholesale electricity procurement costs and natural gas costs are recoverable, fluctuations in electricity and natural gas prices will not affect earnings. Such fluctuations, however, may impact cash flows. The Utility's natural gas transportation and storage costs for core customers are also fully recoverable through a ratemaking mechanism.

The Utility's natural gas transportation and storage costs for non-core customers may not be fully recoverable. The Utility is subject to price and volumetric risk for the portion of intrastate natural gas transportation and storage capacity that has not been sold under long-term contracts providing for the recovery of all fixed costs through the collection of fixed reservation charges. The Utility sells most of its capacity based on the volume of gas that the Utility's customers actually ship, which exposes the Utility to volumetric risk.

The Utility uses value-at-risk to measure its shareholders' exposure to price and volumetric risks resulting from variability in the price of, and demand for, natural gas transportation and storage services that could impact revenues due to changes in market prices and customer demand. Value-at-risk measures this exposure over a rolling 12-month forward period and assumes that the contract positions are held through expiration. This calculation is based on a 95% confidence level, which means that there is a 5% probability that the impact to revenues on a pre-tax basis, over the rolling 12-month forward period, will be at least as large as the reported value-at-risk. Value-at-risk uses market data to quantify the Utility's price exposure. When market data is not available, the Utility uses historical data or market proxies to extrapolate the required market data. Value-at-risk as a measure of portfolio risk has several limitations, including, but not limited to, inadequate indication of the exposure to extreme price movements and the use of historical data or market proxies that may not adequately capture portfolio risk.

The Utility's value-at-risk calculated under the methodology described above was approximately $13 million and $11 million at December 31, 2012 and 2011, respectively. During the 12 months ended December 31, 2012, the Utility's approximate high, low, and average values-at-risk were $13 million, $10 million and $12 million, respectively. And during 2011, the value-at-risk amounts were $11 million, $7 million and $9 million, respectively. (See Note 10 of the Notes to the Consolidated Financial Statements for further discussion of price risk management activities.)

Interest Rate Risk

Interest rate risk sensitivity analysis is used to measure interest rate risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. At December 31, 2012 and December 31, 2011, if interest rates changed by 1% for all current PG&E Corporation and Utility variable rate and short-term debt and investments, the change would affect net income for the next 12 months by $7 million and $13 million, respectively, based on net variable rate debt and other interest rate-sensitive instruments outstanding.

Energy Procurement Credit Risk

The Utility conducts business with counterparties mainly in the energy industry, including other California investor-owned electric utilities, municipal utilities, energy trading companies, financial institutions, and oil and natural gas production companies located in the United States and Canada. If a counterparty fails to perform on its contractual obligation to deliver electricity or gas, then the Utility may find it necessary to procure electricity or gas at current market prices, which may be higher than the contract prices.

The Utility manages credit risk associated with its counterparties by assigning credit limits based on evaluations of their financial conditions, net worth, credit ratings, and other credit criteria as deemed appropriate. Credit limits and credit quality are monitored periodically. The Utility ties many energy contracts to master commodity enabling agreements that may require security (referred to as "Credit Collateral" in the table below). Credit collateral may be in the form of cash or letters of credit. The Utility may accept other forms of performance assurance in the form of corporate guarantees of acceptable credit quality or other eligible securities (as deemed appropriate by the Utility). Credit collateral or performance assurance may be required from counterparties when current net receivables and replacement cost exposure exceed contractually specified limits.

The following table summarizes the Utility's net credit risk exposure to its counterparties, as well as the Utility's credit risk exposure to counterparties accounting for greater than 10% net credit exposure, as of December 31, 2012 and December 31, 2011:

(in millions)	Gross Credit Exposure Before Credit Collateral(1)	Credit Collateral	Net Credit Exposure(2)	Number of Wholesale Customers or Counterparties >10%	Net Credit Exposure to Wholesale Customers or Counterparties >10%
December 31, 2012	$ 94	$ (9)	$ 85	2	62
December 31, 2011	151	(13)	138	2	106

(1) Gross credit exposure equals mark-to-market value on physically and financially settled contracts, and net receivables (payables) where netting is contractually allowed. Gross and net credit exposure amounts reported above do not include adjustments for time value or liquidity.

(2) Net credit exposure is the Gross Credit Exposure Before Credit Collateral minus Credit Collateral (cash deposits and letters of credit). For purposes of this table, parental guarantees are not included as part of the calculation.

CRITICAL ACCOUNTING POLICIES

The preparation of Consolidated Financial Statements in accordance with accounting principles generally accepted in the United States of America ("GAAP") involves the use of estimates and assumptions that affect the recorded amounts of assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The accounting policies described below are considered to be critical accounting policies due, in part, to their complexity and because their application is relevant and material to the financial position and results of operations of PG&E Corporation and the Utility, and because these policies require the use of material judgments and estimates. Actual results may differ substantially from these estimates. These policies and their key characteristics are outlined below.

Regulatory Assets and Liabilities

The Utility's rates are primarily set by the CPUC and the FERC and are designed to recover the cost of providing service. The Utility capitalizes and records, as regulatory assets, costs that would otherwise be charged to expense if it is probable that the incurred costs will be recovered in future rates. Regulatory assets are amortized over the future periods that the costs are expected to be recovered. If costs expected to be incurred in the future are currently being recovered through rates, the Utility records those expected future costs as regulatory liabilities. In addition, the Utility records regulatory liabilities when the CPUC or the FERC requires a refund to be made to customers or has required that a gain or other reduction of net allowable costs be given to customers over future periods.

Determining probability requires significant judgment by management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders, and the strength or status of applications for rehearing or state court appeals. For some of the Utility's regulatory assets, including utility retained generation, the Utility has determined that the costs are recoverable based on specific approval from the CPUC. The Utility also records a regulatory asset when a mechanism is in place to recover current expenditures and historical experience indicates that recovery of incurred costs is probable, such as the regulatory assets for pension benefits; deferred income tax; price risk management; and unamortized loss, net of gain, on reacquired debt. The CPUC has not denied during 2012, 2011, and 2010, the recovery of any material costs previously recognized by the Utility as regulatory assets.

If the Utility determined that it is no longer probable that regulatory assets would be recovered or reflected in future rates, or if the Utility ceased to be subject to rate regulation, the regulatory assets would be charged against income in the period in which that determination was made. At December 31, 2012, PG&E Corporation and the

Utility reported regulatory assets (including current regulatory balancing accounts receivable) of $8.3 billion and regulatory liabilities (including current balancing accounts payable) of $6.1 billion.

Loss Contingencies

Environmental Remediation Liabilities

The Utility is subject to loss contingencies pursuant to federal and California environmental laws and regulations that in the future may require the Utility to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party. Such contingencies may exist for the remediation of hazardous substances at various potential sites, including former MGP sites, power plant sites, gas compressor stations, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous materials, even if the Utility did not deposit those substances on the site.

The Utility generally commences the environmental remediation assessment process upon notification from federal or state agencies, or other parties, of a potential site requiring remedial action. (In some instances, the Utility may initiate action to determine its remediation liability for sites that it no longer owns in cooperation with regulatory agencies. For example, the Utility has begun a program related to certain former MGP sites.) Based on such notification, the Utility completes an assessment of the potential site and evaluates whether it is probable that a remediation liability has been incurred. The Utility records an environmental remediation liability when site assessments indicate remediation is probable and it can reasonably estimate the loss or a range of possible losses. Given the complexities of the legal and regulatory environment and the inherent uncertainties involved in the early stages of a remediation project, the process for estimating remediation liabilities is subjective and requires significant judgment. Key factors evaluated in developing cost estimates include the extent and types of hazardous substances at a potential site, the range of technologies that can be used for remediation, the determination of the Utility's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties.

When possible, the Utility estimates costs using site-specific information, but also considers historical experience for costs incurred at similar sites depending on the level of information available. Estimated costs are composed of the direct costs of the remediation effort and the costs of compensation for employees who are expected to devote a significant amount of time directly to the remediation effort. These estimated costs include remedial site investigations, remediation actions, operations and maintenance activities, post remediation monitoring, and the costs of technologies that are expected to be approved to remediate the site. Remediation efforts for a particular site generally extend over a period of several years. During this period, the laws governing the remediation process may change, as well as site conditions, thereby possibly affecting the cost of the remediation effort.

At December 31, 2012 and 2011, the Utility's accruals for undiscounted gross environmental liabilities were $910 million and $785 million, respectively. The Utility's undiscounted future costs could increase to as much as $1.6 billion if the extent of contamination or necessary remediation is greater than anticipated or if the other potentially responsible parties are not financially able to contribute to these costs, and could increase further if the Utility chooses to remediate beyond regulatory requirements. 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.

Legal and Regulatory Matters

PG&E Corporation and the Utility are subject to various laws and regulations and, in the normal course of business, PG&E Corporation and the Utility are subject to claims or named as parties in lawsuits. In addition, the Utility can incur penalties for failure to comply with federal, state, or local laws and regulations. PG&E Corporation and the Utility record a provision for a loss when it is both probable that a loss has been incurred and the amount of the loss can be reasonably estimated. PG&E Corporation and the Utility evaluate the range of reasonably estimated losses and record a provision based on the minimum amount, unless an amount within the range is a better estimate than any other amount. These accruals, and the estimates of any additional reasonably possible losses (or reasonably possible losses in excess of the amounts accrued), are reviewed quarterly and are adjusted to reflect the impacts of negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. In assessing the amount of such losses, PG&E Corporation's and the Utility's policy is to exclude anticipated legal costs. (See "Legal and Regulatory Contingencies" in Note 15 of the Notes to the Consolidated Financial Statements.)

Asset Retirement Obligations

PG&E Corporation and the Utility account for an asset retirement obligation ("ARO") at fair value in the period during which the legal obligation is incurred if a reasonable estimate of fair value and its settlement date can be made. A legal obligation can arise from an existing or enacted law, statute, or ordinance; a written or oral contract; or under the legal doctrine of promissory estoppel.

At the time of recording an ARO, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. The Utility recognizes a regulatory asset or liability for the timing differences between the recognition of expenses and costs recovered through the ratemaking process.

Most of PG&E Corporation's and the Utility's AROs relate to the Utility's obligation to decommission its nuclear generation facilities and certain fossil fuel-fired generation facilities. The Utility estimates its obligation for the future decommissioning of its nuclear generation facilities and certain fossil fuel-fired generation facilities. In December 2012, the Utility submitted an updated estimate of the cost to decommission its nuclear facilities to the CPUC. The increase in the estimated obligation of $1.3 billion was primarily due to higher spent nuclear fuel disposal costs and an increase in the scope of work. To estimate the liability, the Utility uses a discounted cash flow model based upon significant estimates and assumptions about future decommissioning costs, inflation rates, and the estimated date of decommissioning. The estimated future cash flows are discounted using a credit-adjusted risk-free rate that reflects the risk associated with the decommissioning obligation. (See Note 2 of the Notes to the Consolidated Financial Statements.)

Changes in these estimates and assumptions could materially affect the amount of the recorded ARO for these assets. For example, a premature shutdown of the nuclear facilities at Diablo Canyon would increase the likelihood of an earlier start to decommissioning and cause an increase in the ARO. Additionally, if the inflation adjustment increased 25 basis points, the amount of the ARO would increase by approximately 1.57%. Similarly, an increase in the discount rate by 25 basis points would decrease the amount of the ARO by 4.03%. At December 31, 2012, the Utility's recorded ARO for the estimated cost of retiring these long-lived assets was $2.9 billion.

Pension and Other Postretirement Benefit Plans

PG&E Corporation and the Utility provide a non-contributory defined benefit pension plan for eligible employees as well as contributory postretirement health care and medical plans for eligible retirees and their eligible dependents, and non-contributory postretirement life insurance plans for eligible employees and retirees.

The pension and other postretirement benefit obligations are calculated using actuarial models as of the December 31 measurement date. The significant actuarial assumptions used in determining pension and other benefit obligations include the discount rate, the average rate of future compensation increases, the health care cost trend rate and the expected return on plan assets. PG&E Corporation and the Utility review these assumptions on an annual basis and adjust them as necessary. While PG&E Corporation and the Utility believe that the assumptions used are appropriate, significant differences in actual experience, plan changes or amendments, or significant changes in assumptions may materially affect the recorded pension and other postretirement benefit obligations and future plan expenses.

PG&E Corporation and the Utility recognize the funded status of their respective plans on their respective Consolidated Balance Sheets with an offsetting entry to accumulated other comprehensive income (loss); or, to the extent that the cost of the plans are recoverable in utility rates, to regulatory assets and liabilities, resulting in no impact to their respective Consolidated Statements of Income.

Pension and other benefit expense is based on the differences between actuarial assumptions and actual plan results and is deferred in accumulated other comprehensive income (loss) and amortized into income on a gradual basis. The differences between pension benefit expense recognized in accordance with GAAP and amounts recognized for ratemaking purposes are recorded as regulatory assets or liabilities as amounts are probable of recovery from customers. (See Note 3 of the Notes to the Consolidated Financial Statements.)

PG&E Corporation and the Utility review recent cost trends and projected future trends in establishing health care cost trend rates. This evaluation suggests that current rates of inflation are expected to continue in the near term. In recognition of continued high inflation in health care costs and given the design of PG&E Corporation's plans, the assumed health care cost trend rate for 2012 is 7.5%, gradually decreasing to the ultimate trend rate of 5% in 2018 and beyond.

Expected rates of return on plan assets were developed by determining projected stock and bond returns and then applying these returns to the target asset allocations of the employee benefit trusts, resulting in a weighted average rate of return on plan assets. Fixed-income returns were projected based on real maturity and credit spreads added to a long-term inflation rate. Equity returns were estimated based on estimates of dividend yield and real earnings growth added to a long-term rate of inflation. For the Utility's defined benefit pension plan, the assumed return of 5.4% compares to a ten-year actual return of 10.2%.

The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of approximately 648 Aa-grade non-callable bonds at December 31, 2012. This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other postretirement benefit obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

The following reflects the sensitivity of pension costs and projected benefit obligation to changes in certain actuarial assumptions:

(in millions)	Increase (Decrease) in Assumption	Increase in 2012 Pension Costs	Increase in Projected Benefit Obligation at December 31, 2012
Discount rate	(0.50)%	$ 110	$ 1,262
Rate of return on plan assets	(0.50)%	54	—
Rate of increase in compensation	0.50%	50	308

The following reflects the sensitivity of other postretirement benefit costs and accumulated benefit obligation to changes in certain actuarial assumptions:

(in millions)	Increase (Decrease) in Assumption	Increase in 2012 Other Postretirement Benefit Costs	Increase in Accumulated Benefit Obligation at December 31, 2012
Health care cost trend rate	0.50%	$ 4	$ 53
Discount rate	(0.50)%	2	132
Rate of return on plan assets	(0.50)%	7	—

PG&E Corporation's and the Utility's reputations have been significantly affected by the negative publicity surrounding the San Bruno accident, the related investigations and civil litigation, and the various reports the Utility has submitted to the CPUC to disclose noncompliance with applicable regulations. Their reputations may be further adversely affected by publicity regarding developments in the pending CPUC and criminal investigations, and by future investigations or other regulatory or governmental proceedings that may be commenced, and by media or public scrutiny of the Utility's electricity and natural gas operations. Such further reputational harm or the inability of PG&E Corporation and the Utility to restore their reputations may further affect their financial conditions, results of operations and cash flows.

The reputations of PG&E Corporation and the Utility have seriously suffered as a result of the San Bruno accident for which the Utility has acknowledged liability; the June 2011 investigative report from the CPUC's independent review panel and the August 2011 National Transportation Safety Board ("NTSB") report, both of which criticized the Utility's safety recordkeeping for its natural gas transmission system and the Utility's pipeline installation, integrity management, and other operational practices; and the media coverage of the accident and the related investigations and lawsuits. After the San Bruno accident, the CPUC initiated three investigations pertaining to the Utility's natural gas transmission pipeline operations, including an investigation of the San Bruno accident. (See "Natural Gas Matters" above.) A criminal investigation of the San Bruno accident also has been commenced. The media also has widely reported on the civil lawsuits arising from the San Bruno accident which seek compensation and punitive damages for personal injuries, deaths, and property damage.

In addition, the Utility has notified the SED of various self-identified violations of regulations applicable to natural gas safety and operating practices since December 2011 when the CPUC imposed the self-reporting requirement and authorized the SED to impose penalties based on the self-identified violations. In January 2012, the SED imposed penalties of $17 million on the Utility for self-reported failure to perform certain leak surveys and the SED may impose additional penalties based on other self-reported violations. These self-reports also have received negative media attention.

The Utility's operations are also subject to heightened and well-publicized concerns about many aspects of its operations, such as the Utility's nuclear generation operations at Diablo Canyon and the risks of terrorist acts, earthquakes, or a nuclear accident; the Utility's environmental remediation activities; and the accuracy, privacy, and safety of the Utility's information and operating systems, including those used to measure customer energy usage and generate bills. These concerns have often led to additional adverse media coverage and could later result in investigations or other action by regulators, legislators and law enforcement officials or in lawsuits.

Further, these concerns may cause investors to question management's ability to repair the reputational harm that PG&E Corporation and the Utility have suffered, resulting in an adverse impact on the market price of PG&E Corporation common stock. Given PG&E Corporation's and the Utility's greater equity needs, a declining stock price would cause further dilution in net income per share. The extent to which their reputations can be restored will depend, in part, on the success of the Utility's efforts to improve the safety and reliability of the natural gas system as planned in the Utility's pipeline safety enhancement plan, whether they can respond to the findings and recommendations made by the CPUC's independent review panel and the NTSB, and whether they are able to adequately convince regulators, legislators, law enforcement officials, the media and the public that they have done so. Their ability to repair their reputations also may be affected by developments that may occur in the pending investigations, including the amount of civil or criminal penalties that may be imposed on the Utility; whether there are new investigations or citations; and developments that may occur in the San Bruno accident-related civil litigation. If PG&E Corporation and the Utility are unable to repair their reputations, their financial conditions, results of operations and cash flows may be further negatively affected.

PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially affected by the ultimate amount of penalties imposed on the Utility; the costs of taking required remedial actions; the ultimate amount of criminal penalties, if any, imposed by governmental authorities; and the ultimate amount of third-party liability arising from the San Bruno accident and the availability, timing and amount of related insurance recoveries.

The CPUC has stated that it is prepared to impose substantial penalties on the Utility in connection with the investigations. Although the parties have engaged in settlement discussions in an effort to reach a stipulated outcome to resolve the investigations, the parties have not reached an agreement. If a stipulated outcome is not reached and the CPUC issues a decision that finds that the Utility violated applicable laws, rules or orders, the CPUC can impose penalties of up to $20,000 per day, per violation. (For violations that are considered to have occurred on or after January 1, 2012, the statutory penalty has increased to a maximum of $50,000 per day, per violation.) The CPUC has wide discretion to determine the amount of penalties based on the totality of the circumstances, including such factors as the gravity of the violations; the type of harm caused by the violations and the number of persons affected; and the good faith of the entity charged in attempting to achieve compliance, after notification of a violation. The CPUC is also required to consider the appropriateness of the amount of the penalty to the size of the entity charged. The CPUC has historically exercised this discretion in determining penalties. The SED also has this discretion under the authority delegated to it by the CPUC, but the SED is required to impose the maximum statutory penalty per violation, per day.

PG&E Corporation and the Utility have concluded that it is probable that the Utility will be required to pay penalties in connection with the investigations and potential SED enforcement related to the self-reports and have accrued an amount in their financial statements that reflects the reasonably estimable minimum amount of penalties they believe it is probable that the Utility will incur. After considering the many variables that could affect the ultimate amount of penalties the Utility may be required to pay, PG&E Corporation and the Utility are unable to make a better estimate of the probable loss or estimate the reasonably possible amount of penalties that the Utility could incur in excess of the amount accrued and such amount could be material. In addition to penalties, the Utility could incur significant costs to implement any remedial actions the CPUC may order the Utility to perform.

PG&E Corporation and the Utility also are unable to estimate the amount (or range of amounts) of reasonably possible losses associated with any criminal penalties that may be imposed in connection with the pending criminal investigation. Any civil or criminal penalties imposed on the Utility will not be recoverable from customers. (See Note 15 of the Notes to the Consolidated Financial Statements.) PG&E Corporation and the Utility also have concluded that it is probable that the Utility will incur a loss in connection with the lawsuits arising from the San Bruno accident and have accrued an amount in their financial statements for the reasonably estimable minimum amount of loss. PG&E Corporation and the Utility believe that a significant portion of the third-party liabilities the Utility incurs will be recoverable through insurance, but there is a risk that the insurers could deny coverage for claims under the terms of the policies, deem settlement amounts excessive and not payable, or be financially unable to pay the Utility's claims. Further, although many of the San Bruno lawsuits have been settled, a substantial number of cases are unresolved and plaintiffs continue to pursue compensatory and punitive damages. PG&E Corporation and the Utility are unable to estimate the amount (or range of amounts) of reasonably possible losses associated with any punitive damages that could be awarded to plaintiffs in the civil litigation. (See Note 15 of the Notes to the Consolidated Financial Statements.)

The estimates and assumptions underlying the accrued amounts and the ultimate amount of penalties and third-party losses are subject to change based on the amount of penalties actually imposed by the CPUC or agreed to in a stipulated outcome that may be reached to resolve the investigations, by the outcome of trials in the San Bruno litigation, and the terms of additional settlement agreements that may be reached with remaining plaintiffs. Future changes to estimates and assumptions could result in additional accruals in future periods which could have a material impact on PG&E Corporation's and the Utility's financial condition and results of operations in the period in which they are recognized.

PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows have been, and will continue to be, materially affected by costs incurred by the Utility to perform work under its pipeline safety enhancement plan, to undertake other pipeline-related work, and to improve the safety and reliability of its natural gas and electricity operations.

Although the CPUC approved most of the proposed scope and timing of projects under the Utility's pipeline safety enhancement plan, the CPUC disallowed the Utility's request for rate recovery of a significant portion of capital costs and expenses through 2014, including costs of pressure testing pipelines placed into service after January 1, 1956 for which the Utility is unable to produce pressure test records. The CPUC may disallow additional costs based on the final results of the Utility's pipeline records search and pipeline pressure validation work, which the Utility expects to complete by May 2013. (See "Natural Gas Matters" above.) The Utility will be unable to recover any costs in excess of the adopted capital and expense amounts and the adopted amounts will be reduced by the cost of any plan project not completed during the first phase and not replaced with a higher priority project. Further, actual costs for 2013 and 2014 may be materially higher than the Utility currently forecasts. During 2013, the Utility expects to request that the CPUC approve the proposed timing, scope and cost recovery for the first three years (2015, 2016, and 2017) of the second phase of the plan beginning on January 1, 2015. While the Utility's request will include updated cost forecasts based on the Utility's experience during the first phase, there is some risk that categories of costs that were disallowed by the CPUC in its decision on the first phase also will be disallowed in the second phase.

In addition, the Utility forecasts that it will incur additional costs outside of the scope of the pipeline safety enhancement plan in 2013 and 2014 that are not expected to be recoverable through rates. This includes costs to establish the parameters of the Utility's "rights-of-way" surrounding pipelines and to identify and remove encroachments from these pipeline rights-of-way. The Utility also forecasts it will continue to incur additional costs associated with the integrity of transmission pipelines, conduct other gas-related work, and legal and regulatory expenses. The Utility also forecasts that it will incur costs to improve electric and gas distribution operations in 2013 that exceed the amounts assumed when rates were set in the last rate cases. (See "Operating and Maintenance" above.) Actual costs may be materially higher than forecast. Further, as the Utility continues to review its natural gas system and operating practices and as industry practices and standards evolve, the Utility may undertake additional work in the future to improve the safety and reliability of its natural gas utility services, for example, to validate the maximum allowable operating pressure of other facilities in its natural gas transmission system, such as compressor stations. The Utility may be unable to recover the costs of such additional work through rates. The Utility also may incur third-party liability related to service disruptions caused by changes in pressure on its natural gas transmission system as work is performed.

PG&E Corporation's and the Utility's financial condition depends upon the Utility's ability to recover its operating expenses and its electricity and natural gas procurement costs and to earn a reasonable rate of return on capital investments, in a timely manner from the Utility's customers through regulated rates.

The Utility's ability to recover its costs and earn its authorized rate of return can be affected by many factors, including the time lag between when costs are incurred and when those costs are recovered in customers' rates and differences between the forecast or authorized costs embedded in rates (which are set on a prospective basis) and the amount of actual costs incurred. (See "Regulatory Matters—2014 General Rate Case" above.) The CPUC or the FERC may not allow the Utility to recover costs on the basis that such costs were not reasonably or prudently incurred or for other reasons. For example, the CPUC has prohibited the Utility from recovering a material portion of costs that the Utility has already incurred, and will continue to incur, as it performs work under the pipeline safety enhancement plan, in part, because the CPUC found that such costs were incurred as a result of imprudent management. The CPUC may order the Utility to propose cost-sharing methods for certain costs or the Utility may decide for other reasons not to seek recovery of certain costs. In either case, the Utility would incur costs that are not recovered through rates. (See "Natural Gas Matters" above.)

Further, to serve its customers in a safe and reliable manner, the Utility may be required to incur expenses before the CPUC approves the recovery of such costs. The Utility is generally unable to recover costs incurred before CPUC authorization is obtained, unless the CPUC authorizes the Utility to track costs for potential future recovery. For example, the Utility requested that the CPUC allow the Utility to track costs incurred in 2012 under the pipeline safety enhancement plan before the CPUC approved the plan. The CPUC did not address the Utility's request and as a result the Utility was unable to recover costs incurred before the effective date of the decision, December 20, 2012. The Utility's failure to recover these and other pipeline-related costs has materially affected PG&E Corporation's and the Utility's financial condition, results of operations and cash flows.

Fluctuating commodity prices, changes in laws and regulations or changes in the political and regulatory environment also may have an adverse effect on the Utility's ability to timely recover its costs and earn its authorized rate of return. Current law and regulatory mechanisms permit the Utility to pass through its costs to procure electricity and natural gas to customers in rates. A significant and sustained rise in commodity prices, caused by costs associated with new renewable energy resources and California's new cap-and-trade program and other factors, could create overall rate pressures that make it more difficult for the Utility to recover its costs. This pressure could increase as the Utility continues to collect authorized rates to support public purpose programs, such as energy efficiency programs, and low-income rate subsidies, and to fund customer incentive programs. Further, current California law restricts the ability of the CPUC to adjust electricity rates for certain customer classes which could lead to a perception that some customers are unfairly subsidizing other customers and that some commercial customers are competitively disadvantaged as compared to similar customers in other states. The customer concerns caused by these perceived inequities could also make it more difficult for the Utility to recover its operational costs.

The Utility's ability to recover its costs also may be affected by the economy and the economy's corresponding impact on the Utility's customers. For example, a sustained downturn or sluggishness in the economy could reduce the Utility's sales to industrial and commercial customers. Although the Utility generally recovers its costs through rates, regardless of sales volume, rate pressures increase when the costs are borne by a smaller sales base. A portion of the Utility's revenues depends on the level of customer demand for the Utility's natural gas transportation services which can fluctuate based on economic conditions, the price of natural gas, and other factors.

The Utility's failure to recover its operating expenses, including electricity and natural gas procurement costs in a timely manner through rates could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

The Utility's ability to procure electricity to meet customer demand at reasonable prices and recover procurement costs timely may be affected by increasing renewable energy requirements, the continuing functioning of the wholesale electricity market in California, and the new cap-and-trade market.

The Utility meets customer demand for electricity from a variety of sources, including electricity generated from the Utility's own generation facilities, electricity provided by third parties under power purchase agreements, and purchases on the wholesale electricity market. The Utility must manage these sources using the principles of "least cost dispatch."

The Utility enters into power purchase agreements, including contracts to purchase renewable energy, in compliance with a long-term procurement plan approved by the CPUC. The Utility executes power purchase agreements following competitive requests for offers. The Utility submits the winning contracts to the CPUC for approval and authorization to recover contract costs through rates. There is a risk that the contractual prices the Utility is required to pay will become uneconomic in the future for a variety of reasons, including developments in alternative energy technology, increased self-generation by customers, an increase in distributed generation, and lower customer demand due to economic conditions or the loss of the Utility's customers to other generation providers. In particular, as the market for renewable energy develops in response to California's renewable energy requirements, there is a risk that the Utility's contractual commitments could result in procurement costs that are higher than the market price of renewable energy. This could create a further risk that, despite original CPUC approval of the contracts, the CPUC would disallow contract costs in the future if the CPUC determines that the costs are unreasonably above market. In addition, the CPUC could disallow procurement costs if the CPUC determined that the Utility incurred procurement costs that were not in compliance with its CPUC-approved procurement plan, or that the Utility did not prudently administer the power purchase agreements that were executed in compliance with the plan. The Utility also purchases energy through the day-ahead wholesale electricity market operated by the California Independent System Operator ("CAISO"). The amount of electricity the Utility purchases on the wholesale market fluctuates due to a variety of factors, including, the level of electricity generated by the Utility's own generation facilities, changes in customer demand, periodic expirations or terminations of power purchase contracts, the execution of new power purchase contracts, fluctuation in the output of hydroelectric and other renewable power facilities owned or under contract by the Utility, and the implementation of new energy efficiency and demand response programs. The market prices of electricity also fluctuate. Although market mechanisms are designed to limit excessive prices, these market mechanisms could fail, or the related systems and software on which the market mechanisms rely may not perform as intended, which could result in excessive market prices. For example, during the 2000 and 2001 energy crisis, the market mechanism flaws in California's newly established wholesale electricity market led to dramatically high market prices for electricity that the Utility was unable to recover through customer rates, ultimately causing the Utility to file a petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code.

In addition, with the beginning of the first compliance period under the new California cap-and-trade regulations on January 1, 2013, electricity costs include associated cap-and-trade compliance costs. Although some of these costs will be offset by revenues from the sale of emission allowances by the Utility on behalf of some classes of electricity customers, it is uncertain how the cap-and-trade market will develop in the future especially as the cap-and-trade compliance periods expand to cover other sources of GHG emissions and as other regional or federal cap-and-trade programs are adopted.

PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially affected if the Utility is unable to recover a material portion of the costs it incurs to deliver electricity to customers.

The completion of capital investment projects is subject to substantial risks, and the timing of the Utility's capital expenditures and recovery of capital-related costs through rates, if at all, will directly affect net income.

The Utility's ability to invest capital in its electric and natural gas businesses is subject to many risks, including risks related to obtaining regulatory approval, securing adequate and reasonably priced financing, obtaining and complying with the terms of permits, meeting construction budgets and schedules, and satisfying operating and environmental performance standards. Third-party contractors on which the Utility depends to develop or construct these projects also face many of these risks. Changes in tax laws or policies, such as those relating "bonus" depreciation, may also affect when or whether a potential project is developed. In addition, reduced forecasted demand for electricity and natural gas as a result of an economic slow-down, or other reasons, may also increase the risk that projects are deferred, abandoned, or cancelled. Some of the Utility's future capital investments may also be affected by evolving federal and state policies regarding the development of a "smart" electric transmission grid.

In addition, differences in the amount or timing of actual capital expenditures compared to the amount and timing of forecast capital expenditures authorized to be recovered through rates, can directly affect net income. Further, if capital expenditures are disallowed, the Utility would be required to write-off such expenses which could have a material effect on PG&E Corporation's and the Utility's financial condition and results of operations.

PG&E Corporation's and the Utility's financial results could be affected by the loss of Utility customers and decreased new customer growth due to municipalization, an increase in the number of community choice aggregators, increasing levels of "direct access," and the development and integration of self-generation and distributed generation technologies, if the CPUC fails to adjust the Utility's rates to reflect such events.

The Utility's customers could bypass its distribution and transmission system by obtaining such services from other providers. This may result in stranded investment capital, loss of customer growth, and additional barriers to cost recovery. Forms of bypass of the Utility's electricity distribution system include construction of duplicate distribution facilities to serve specific existing or new customers. In addition, local government agencies could exercise their power of eminent domain to acquire the Utility's facilities and use the facilities to provide utility service to their local residents and businesses. The Utility may be unable to fully recover its investment in the distribution assets that it no longer owns. The Utility's natural gas transmission facilities could be bypassed by interstate pipeline companies that construct facilities in the Utility's markets, by customers who build pipeline connections that bypass the Utility's natural gas transmission and distribution system, or by customers who use and transport liquefied natural gas.

Alternatively, the Utility's customers could become direct access customers who purchase electricity from alternative energy suppliers or they could become customers of governmental bodies registered as community choice aggregators to purchase and sell electricity for their residents and businesses. Although the Utility is permitted to collect a non-bypassable charge for generation-related costs incurred on behalf of these customers, or distribution, metering, or other services it continues to provide, the fee may not be sufficient for the Utility to fully recover the costs to provide these services. Furthermore, if the former customers return to receiving electricity supply from the Utility, the Utility could incur costs to meet their electricity needs that it may not be able to timely recover through rates or that it may not be able to recover at all.

In addition, increasing 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 for surplus power at the full retail rate, could put upward rate pressure on remaining customers. Also, a confluence of technology-related cost declines and sustained federal or state subsidies make a combination of distributed generation and storage a viable, cost-effective alternative to the Utility's bundled electric service which could further threaten the Utility's ability to recover its generation, transmission, and distribution investments.

If the CPUC fails to adjust the Utility's rates to reflect the impact of changing loads, increasing self-generation and net energy metering, and the growth of distributed generation, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially adversely affected.

The operation of the Utility's electricity and natural gas generation, transmission, and distribution facilities involve significant risks which, if they materialize, can adversely affect PG&E Corporation's and the Utility's financial condition, results of operations and cash flows, and the Utility's insurance may not be sufficient to cover losses caused by an operating failure or catastrophic event.

The Utility owns and operates extensive electricity and natural gas facilities, including two nuclear generation units and an extensive hydroelectric generating system. The Utility's service territory covers approximately 70,000 square miles in northern and central California and is composed of diverse geographic regions with varying climates and weather conditions that create numerous operating challenges. The Utility's facilities are interconnected to the U.S. western electricity grid and numerous interstate and continental natural gas pipelines. The Utility's ability to earn its authorized rate of return depends on its ability to efficiently maintain and operate its facilities and provide electricity and natural gas services safely and reliably. The maintenance and operation of the Utility's facilities, and the facilities of third parties on which the Utility relies, involve numerous risks, including the risks discussed elsewhere in this section and those that arise from:

- the breakdown or failure of equipment, electric transmission or distribution lines, or natural gas transmission and distribution pipelines, that can cause explosions, fires, or other catastrophic events;
- the failure of generation facilities to perform at expected or at contracted levels of output or efficiency;
- the failure of a large dam or other major hydroelectric facility;
- the failure to take expeditious or sufficient action to mitigate operating conditions, facilities, or equipment, that the Utility has identified, or reasonably should have identified, as unsafe, which failure then leads to a catastrophic event;
- severe weather events such as storms, tornadoes, floods, drought, earthquakes, tsunamis, wildland and other fires, pandemics, solar events, electromagnetic events, or other natural disasters;
- operator or other human error;
- fuel supply interruptions or the lack of available fuel which reduces or eliminates the Utility's ability to provide electricity and/or natural gas service;
- the release of hazardous or toxic substances into the air or water;
- use of new or unproven technologies;
- cyber-attack; and
- acts of terrorism, vandalism, or war.

The occurrence of any of these events could affect demand for electricity or natural gas; cause unplanned outages or reduce generating output which may require the Utility to incur costs to purchase replacement power; cause damage to the Utility's assets or operations requiring the Utility to incur unplanned expenses to respond to emergencies and make repairs; damage the assets or operations of third parties on which the Utility relies; subject the Utility to claims by customers or third parties for damages to property, personal injury, or wrongful death, or subject the Utility to penalties. These costs may not be recoverable through rates or insurance. Insurance, equipment warranties, or other contractual indemnification requirements may not be sufficient or effective to provide full or even partial recovery under all circumstances or against all hazards or liabilities to which the Utility may become subject. An uninsured loss could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows. Future insurance coverage may not be available at rates and on terms as favorable as the rates and terms of the Utility's current insurance coverage or may not be available at all.

The Utility's operational and information systems on which it relies to conduct its business and serve customers could fail to function properly due to technological problems, a cyber-attack, acts of terrorism, severe weather, a solar event, an electromagnetic event, a natural disaster, the age and condition of information technology assets, human error, or other reasons, that could disrupt the Utility's operations and cause the Utility to incur unanticipated losses and expense.

The operation of the Utility's extensive electricity and natural gas systems rely on evolving information and operational technology systems and network infrastructures that are becoming more complex as new technologies and systems are implemented to modernize capabilities to safely and reliably deliver gas and electric services. The Utility's business is highly dependent on its ability to process and monitor, on a daily basis, a very large number of tasks and transactions, many of which are highly complex. The failure of the Utility's information and operational systems and networks could significantly disrupt operations; result in public and employee safety lapse; result in outages; reduced generating output; damage to the Utility's assets or operations or those of third parties; and subject the Utility to claims by customers or third parties, any of which could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

The Utility's systems, including its financial information, operational systems, advanced metering, and billing systems, require constant maintenance, modification, and updating, which can be costly and increases the risk of errors and malfunction. Any disruptions or deficiencies in existing systems, or disruptions, delays or deficiencies in the modification or implementation of new systems, could result in increased costs, the inability to track or collect revenues, the diversion of management's and employees' attention and resources, and could negatively affect the effectiveness of the companies' control environment, and/or the companies' ability to timely file required regulatory reports.

The Utility's ability to measure customer energy usage and generate bills depends on the successful functioning of the advanced metering system. The Utility relies on third party contractors and vendors to service, support, and maintain certain proprietary functional components of the advanced metering system. If such a vendor or contractor ceased operations, if there was a contractual dispute or a failure to renew or negotiate the terms of a contract so that the Utility becomes unable to continue relying on such a third-party vendor or contractor, then the Utility could experience costs associated with disruption of billing and measurement operations and would incur costs as it seeks to find other replacement contractors or vendors or hire and train personnel to perform such services.

Despite implementation of security and mitigation measures, all of the Utility's technology systems are vulnerable to disability or failures due to cyber-attacks, viruses, human errors, acts of war or terrorism, and other events. If the Utility's information technology systems or network infrastructure were to fail, the Utility might be unable to fulfill critical business functions and serve its customers, which could have a material effect on PG&E Corporation's and the Utility's financial conditions, results of operations, and cash flows.

In addition, in the ordinary course of its business, the Utility collects and retains sensitive information including personal identification information about customers and employees, customer energy usage, and other confidential information. The theft, damage, or improper disclosure of sensitive electronic data can subject the Utility to penalties for violation of applicable privacy laws, subject the Utility to claims from third parties, and harm the Utility's reputation.

The Utility's success depends on the availability of the services of a qualified workforce and its ability to maintain satisfactory collective bargaining agreements which cover a substantial number of employees. PG&E Corporation's and the Utility's results may suffer if the Utility is unable to attract and retain qualified personnel and senior management talent, or if prolonged labor disruptions occur.

The Utility's workforce is aging and many employees will become eligible to retire within the next few years. Although the Utility has undertaken efforts to recruit and train new field service personnel, the Utility may not be successful. The Utility may be faced with a shortage of experienced and qualified personnel. The majority of the Utility's employees are covered by collective bargaining agreements with three unions. The terms of these agreements affect the Utility's labor costs. It is possible that labor disruptions could occur. In addition, it is possible that some of the remaining non-represented Utility employees will join one of these unions in the future. It is also possible that PG&E Corporation and the Utility may face challenges in attracting and retaining senior management talent especially if they are unable to restore the reputational harm generated by the negative publicity stemming from the San Bruno accident. Any such occurrences could negatively impact PG&E Corporation's and the Utility's financial condition and results of operations.

The operation and decommissioning of the Utility's nuclear power plants expose it to potentially significant liabilities that it may not be able to recover from its insurance or other sources, and the Utility may incur significant capital expenditures and compliance costs that it may be unable to fully recover, adversely affecting PG&E Corporation's and the Utility's s financial conditions, results of operations, and cash flows.

The operation of the Utility's nuclear generation facilities expose it to potentially significant liabilities from environmental, health and financial risks, such as risks relating to the storage, handling and disposal of spent nuclear fuel, the release of radioactive materials caused by a nuclear accident, seismic activity, natural disaster, or terrorist act. There are also significant uncertainties related to the regulatory, technological, and financial aspects of decommissioning nuclear generation plants when their licenses expire. To reduce the Utility's financial exposure to these risks, the Utility maintains insurance and manages decommissioning trusts that hold nuclear decommissioning charges collected through customer rates. However, the costs or damages the Utility may incur in connection with the operation and decommissioning of its nuclear power plants could exceed the amount of the Utility's insurance coverage and nuclear decommissioning trust assets. The Utility has insurance coverage for property damages and business interruption losses, as well as coverage for acts of terrorism at its nuclear power plants as a member of Nuclear Electric Insurance Limited ("NEIL"), a mutual insurer owned by utilities with nuclear facilities. NEIL provides coverage for both nuclear (meaning that nuclear material is released) and non-nuclear losses. Due to multiple large non-nuclear losses in the industry, NEIL has notified the Utility and the other NEIL members that it will be significantly reducing its coverage for non-nuclear losses. This change will affect the Utility beginning in April 2013. While the Utility is seeking alternative insurance options, efforts to obtain additional coverage may not be successful. Even if the Utility is able to obtain additional coverage, this future insurance coverage is not likely to be available at rates and on terms as favorable as the rates and terms of the Utility's current NEIL insurance coverage. If the Utility incurs losses that are either not covered by insurance or exceed the amount of insurance available, such losses could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

In addition, as an operator of the two operating nuclear reactor units at Diablo Canyon, the Utility may be required under federal law to pay up to $235 million of liabilities arising out of each nuclear incident occurring not only at the Utility's Diablo Canyon facility but at any other nuclear power plant in the United States. (See Note 15 of the Notes to the Consolidated Financial Statements.) The Utility's ability to continue to operate its nuclear generation facilities also is subject to the availability of adequate nuclear fuel supplies on terms that the CPUC will find reasonable.

The NRC oversees the licensing, construction, and decommissioning of nuclear facilities and has broad authority to impose requirements relating to the maintenance and operation of nuclear facilities; the storage, handling and disposal of spent fuel; and the safety, radiological, environmental, and security aspects of nuclear facilities. The NRC has adopted regulations that are intended to protect nuclear facilities, nuclear facility employees, and the public from potential terrorist and other threats to the safety and security of nuclear operations, including threats posed by radiological sabotage or cyber-attack. The Utility incurs substantial costs to comply with these regulations. In addition, in March 2012, the NRC issued several orders to the owners of all U.S. operating nuclear reactors to implement the highest-priority recommendations issued by the NRC's task force to incorporate the lessons learned from the March 2011 earthquake and tsunami that caused significant damage to the Fukushima-Dai-ichi nuclear facilities in Japan. The NRC may issue further orders to implement the recommendations, including facility-specific orders, which could require the Utility to incur additional costs.

The Utility has filed an application at the NRC to renew the operating licenses for the two operating units at Diablo Canyon which expire in 2024 and 2025. In May 2011, after the Fukushima-Dai-ichi event, the NRC granted the Utility's request to delay processing the Utility's application until certain advanced seismic studies that the CPUC ordered the Utility to conduct were completed. In November 2012, the California Coastal Commission denied the Utility's request for permits to conduct some of these advanced studies. The Utility is assessing whether it has sufficient seismic data without conducting the high energy off-shore studies or if other studies are needed. It is uncertain when the Utility would request the NRC to resume the relicensing proceeding. In order to receive renewed operating licenses, the Utility also must undergo a sufficiency review by the California Coastal Commission. The disposition of the Utility's relicensing application also will be affected by the terms and timing of the NRC's "waste confidence" decision regarding the environmental impacts of the storage of spent nuclear fuel. The NRC's original "waste confidence decision" in which the NRC found that spent nuclear fuel can be safely managed until a permanent off-site repository is established, was successfully challenged on the basis that the NRC's environmental review was deficient. In August 2012, the NRC ruled that it will not issue final decisions in licensing or re-licensing proceedings, including the Utility's re-licensing application, until it had reconsidered the waste confidence issues. The NRC stated that it would consider all available options for resolving the waste confidence issue, which could include generic or site-specific NRC actions, or some combination of both. The NRC has instructed its staff to develop and issue a new waste confidence decision and temporary storage rule by September 2014.

The CPUC has authority to determine the rates the Utility can collect to recover its nuclear fuel, operating, maintenance, compliance, and decommissioning costs. The Utility also could incur significant expense to comply with regulations or orders the NRC may issue in the future to impose new safety requirements, to obtain license renewal, and to comply with federal and state policies and regulations applicable to the use of cooling water intake systems at generation facilities, such as Diablo Canyon. (See "Environmental Matters" above.) The Utility expects that it would seek rate recovery of these additional costs. The outcome of these rate proceedings at the CPUC can be influenced by public and political opposition to nuclear power. If the Utility were unable to recover costs related to its nuclear facilities, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially affected. The Utility may determine that it cannot comply with the new regulations or orders in a feasible and economic manner and voluntarily cease operations at Diablo Canyon. Alternatively, the NRC may order the Utility to cease its nuclear operations until it can comply with new regulations or orders. Further, the Utility could fail to obtain renewed operating licenses for Diablo Canyon requiring nuclear operations to cease when the current licenses expire in 2024 and 2025.

The Utility's operations are subject to extensive environmental laws and changes in or liabilities under these laws could adversely affect PG&E Corporation's and the Utility's financial conditions, results of operations, and cash flows.

The Utility's operations are subject to extensive federal, state, and local environmental laws, regulations, orders, relating to air quality, water quality and usage, remediation of hazardous wastes, and the protection and conservation of natural resources and wildlife. The Utility can incur significant capital, operating, and other costs associated with compliance with these environmental statutes, rules, and regulations. These costs can be difficult to forecast because the extent of contamination may be unknown. For example, the Utility's costs to perform hydrostatic pressure testing of natural gas pipelines have included costs to obtain local agency and environmental permits to conduct the tests as well as costs to treat and dispose of the water used in the tests that becomes contaminated as the water travels through the pipes. Further, even if the extent of contamination is known, remediation costs can be difficult to estimate due to many factors, including which remediation alternatives will be used, the applicable remediation levels, and the financial ability of other potentially responsible parties. Environmental remediation costs could increase in the future as a result of new legislation, the current trend toward more stringent standards, and stricter and more expansive application of existing environmental regulations. Failure to comply with these laws and regulations, or failure to comply with the terms of licenses or permits issued by environmental or regulatory agencies, could expose the Utility to claims by third parties or the imposition of civil or criminal penalties or other sanctions.

The Utility has been, and may be, required to pay for environmental remediation costs at sites where it is identified as a potentially responsible party under federal and state environmental laws. These sites, some of which the Utility no longer owns, include former manufactured gas plant sites, current and former power plant sites, former gas gathering and gas storage sites, sites where natural gas compressor stations are located, current and former substations, service center and general construction yard sites, and sites currently and formerly used by the Utility for the storage, recycling, or disposal of 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. (See Note 15 to the Notes to the Consolidated Financial Statements for more information.)

The CPUC has authorized the Utility to recover its environmental remediation costs for certain sites through various ratemaking mechanisms. One of these mechanisms allows the Utility rate recovery for 90% of its hazardous substance remediation costs for certain approved sites without a reasonableness review. The CPUC may discontinue or change these ratemaking mechanisms in the future or the Utility may incur environmental costs that exceed amounts the CPUC has authorized the Utility to recover in rates.

Further, the CPUC has ruled that the Utility's environmental costs for certain sites, such as the remediation costs associated with the Hinkley natural gas compressor site, are not recoverable through this ratemaking mechanism. The Utility's costs to remediate groundwater contamination near the Hinkley natural gas compressor site and to abate the effects of the contamination have had, and may continue to have, a material effect on PG&E Corporation's and the Utility's financial conditions, results of operations, and cash flows. (See "Environmental Matters" above.)

The Utility's future operations may be affected by climate change that may have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

A report issued in 2012 by the EPA entitled, "Climate Change Indicators in the United States, 2012" states that the increase of GHG emissions in the atmosphere is changing the fundamental measures of climate in the United States, including rising temperatures, shifting snow and rainfall patterns, and more extreme climate events. In December 2009, the EPA issued a finding that GHG emissions cause or contribute to air pollution that endangers public health and welfare. The impact of events or conditions caused by climate change could range widely, from highly localized to worldwide, and the extent to which the Utility's operations may be affected is uncertain. For example, if reduced snowpack decreases the Utility's hydroelectric generation, the Utility will need to acquire additional generation from other sources. Under certain circumstances, the events or conditions caused by climate change could result in a full or partial disruption of the ability of the Utility—or one or more of the entities on which it relies—to generate, transmit, transport, or distribute electricity or natural gas. The Utility has been studying the potential effects of climate change on the Utility's operations and is developing contingency plans to adapt to those events and conditions that the Utility believes are most significant. Events or conditions caused by climate change could have a greater impact on the Utility's operations than the Utility's studies suggest and could result in lower revenues or increased expenses, or both. If the CPUC fails to adjust the Utility's rates to reflect the impact of events or conditions caused by climate change, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially affected.

The Utility is subject to penalties for failure to comply with federal, state, or local statutes and regulations. Changes in the political and regulatory environment could cause federal and state statutes, regulations, rules, and orders to become more stringent and difficult to comply with, and required permits, authorizations, and licenses may be more difficult to obtain, increasing the Utility's expenses or making it more difficult for the Utility to execute its business strategy.

The Utility must comply in good faith with all applicable statutes, regulations, rules, tariffs, and orders of the CPUC, the FERC, the NRC, and other regulatory agencies relating to the aspects of its electricity and natural gas utility operations that fall within the jurisdictional authority of such agencies. In addition to the NRC requirements described above, these include meeting new renewable energy delivery requirements, resource adequacy requirements, federal electric reliability standards, customer billing, customer service, affiliate transactions, vegetation management, operating and maintenance practices, and safety and inspection practices. The Utility is subject to penalties and sanctions for failure to comply with applicable statutes, regulations, rules, tariffs, and orders.

On January 1, 2012, the CPUC's statutory authority to impose penalties increased from up to $20,000 per day, per violation, to up to $50,000 per day, per violation. The CPUC has wide discretion to determine, based on the facts and circumstances, whether a single violation or multiple violations were committed and to determine the length of time a violation existed for purposes of calculating the amount of penalties. The CPUC has delegated authority to the SED to levy citations and impose penalties for violations of certain regulations related to the safety of natural gas facilities and utilities' natural gas operating practices. Like the CPUC, the SED has discretion to determine how to count the number of violations, but the delegated authority requires the SED to assess the maximum statutory fine per violation. (For a discussion of pending investigations and potential enforcement proceedings, see MD&A "Natural Gas Matters" above.) There is a risk that the CPUC could delegate additional enforcement authority to its staff or that legislation could be enacted to require the CPUC to further delegate enforcement authority.

In addition, the federal Pipeline and Hazardous Materials Safety Administration can impose penalties for violation of federal pipeline safety regulations in amounts that range from $100,000 to $200,000 for an individual violation and from $1 million to $2 million for a series of violations.

The Utility must comply with federal electric reliability standards that are set by the North American Electric Reliability Corporation and approved by the FERC. These standards relate to maintenance, training, operations, planning, vegetation management, facility ratings, and other subjects. These standards are designed to maintain the reliability of the nation's bulk power system and to protect the system against potential disruptions from cyber-attacks and physical security breaches. The FERC can impose penalties (up to $1 million per day, per violation) for failure to comply with these mandatory electric reliability standards. As these and other standards and rules evolve, and as the wholesale electricity markets become more complex, the Utility's risk of noncompliance may increase.

In addition, statutes, regulations, rules, tariffs, and orders, or their interpretation and application, may become more stringent and difficult to comply with in the future. If this occurs, the Utility could be exposed to increased costs to comply with the more stringent requirements or new interpretations and to potential liability for customer refunds, penalties, or other amounts. If it is determined that the Utility did not comply with applicable statutes, regulations, rules, tariffs, or orders, and the Utility is ordered to pay a material amount in customer refunds, penalties, or other amounts, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows would be materially affected.

The Utility also must comply with the terms of various permits, authorizations, and licenses. These permits, authorizations, and licenses may be revoked or modified by the agencies that granted them if facts develop that differ significantly from the facts assumed when they were issued. In addition, discharge permits and other approvals and licenses often have a term that is less than the expected life of the associated facility. Licenses and permits may require periodic renewal, which may result in additional requirements being imposed by the granting agency. In connection with a license renewal for one or more of the Utility's hydroelectric generation facilities or assets, the FERC may impose new license conditions that could, among other things, require increased expenditures or result in reduced electricity output and/or capacity at the facility.

If the Utility cannot obtain, renew, or comply with necessary governmental permits, authorizations, or licenses, or if the Utility cannot recover any increased costs of complying with additional license requirements or any other associated costs in its rates in a timely manner, PG&E Corporation's and the Utility's financial condition and results of operations could be materially affected.

Market performance or changes in other assumptions could require PG&E Corporation and the Utility to make significant unplanned contributions to its pension plan, other postretirement benefits plans, and nuclear decommissioning trusts.

PG&E Corporation and the Utility provide defined benefit pension plans and other postretirement benefits for eligible employees and retirees. The Utility also maintains three trusts for the purposes of providing funds to decommission its nuclear facilities. Up to approximately 60% of the plan assets and trust assets have generally been invested in equity securities, which are subject to market fluctuation. A decline in the market value may increase the funding requirements for these plans and trusts.

The cost of providing pension and other postretirement benefits is also affected by other factors, including the assumed rate of return on plan assets, employee demographics, discount rates used in determining future benefit obligations, rates of increase in health care costs, levels of assumed interest rates, future government regulation, and prior contributions to the plans. Similarly, funding requirements for the nuclear decommissioning trusts are affected by changes in the laws or regulations regarding nuclear decommissioning or decommissioning funding requirements, changes in assumptions as to decommissioning dates, technology and costs of labor, materials and equipment change, and assumed rate of return on plan assets. For example, changes in interest rates affect the liabilities under the plans: as interest rates decrease, the liabilities increase, potentially increasing the funding requirements.

The Utility has recorded an asset retirement obligation related to decommissioning its nuclear facilities based on various estimates and assumptions. Changes in these estimates and assumptions can materially affect the amount of the recorded asset retirement obligation. (See Note 2 of the Notes to the Consolidated Financial Statements for a discussion of the increase in the recorded asset retirement obligation to reflect increased estimated decommissioning costs.)

The CPUC has authorized the Utility to recover forecasted costs to fund pension and postretirement plan contributions and nuclear decommissioning through rates. If the Utility is required to make significant unplanned contributions to fund the pension and postretirement plans and nuclear decommissioning trusts and is unable to recover such contributions in rates, the contributions would negatively affect PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

Other Utility obligations, such as its workers' compensation obligations, are not separately earmarked for recovery through rates. Therefore, increases in the Utility's workers' compensation liabilities and other unfunded liabilities also can negatively affect net income.

PG&E Corporation's and the Utility's financial statements reflect various estimates, assumptions, and values and are prepared in accordance with applicable accounting rules, standards, policies, guidance, and interpretations, including those related to regulatory assets and liabilities. Changes to these estimates, assumptions, values, and accounting rules, or changes in the application of these rules, could materially affect PG&E Corporation's and the Utility's financial condition or results of operations.

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of revenues, expenses, assets, and liabilities, and the disclosure of contingencies. (See the discussion under Notes 1 and 2 of the Notes to the Consolidated Financial Statements and "Critical Accounting Policies" above.) If the information on which the estimates and assumptions are based proves to be incorrect or incomplete, if future events do not occur as anticipated, or if there are changes in applicable accounting guidance, policies, or interpretation, management's estimates and assumptions will change as appropriate. A change in management's estimates or assumptions, or the recognition of actual losses that differ from the amount of estimated losses, could have a material impact on PG&E Corporation's and the Utility's financial condition or results of operations.

As a regulated entity, the Utility's rates are designed to recover the costs of providing service. The Utility capitalizes and records, as regulatory assets, costs that would otherwise be charged to expense if it is probable that the incurred costs will be recovered in future rates. If costs expected to be incurred in the future are currently being recovered through rates, the Utility records those expected future costs as regulatory liabilities. At December 31, 2012, PG&E Corporation and the Utility reported regulatory assets of $8.3 billion and regulatory liabilities of $6.1 billion. (See Note 3 of the Notes to the Consolidated Financial Statements.) Management believes that currently available facts support the continued application of regulatory accounting and that all regulatory assets and liabilities are recoverable or refundable in the current rate environment. Since the San Bruno accident in September 2010, the Utility has recorded cumulative charges of approximately $1.83 billion related to its natural gas operations that are not recoverable through rates. To the extent that rates are not set at a level that allows the Utility to recover the cost of providing service and a reasonable return on its investment in future periods, the Utility may be required to discontinue the application of regulatory accounting for portions of its operations. If that occurs, the related regulatory assets and liabilities would be charged against income in the period in which that determination was made and could have a material impact on PG&E Corporation's and the Utility's future financial condition and results of operations.

As a holding company, PG&E Corporation depends on cash distributions and reimbursements from the Utility to meet its debt service and other financial obligations and to pay dividends on its common stock.

PG&E Corporation is a holding company with no revenue generating operations of its own. PG&E Corporation's ability to pay interest on its outstanding debt, the principal at maturity, and to pay dividends on its common stock, as well as satisfy its other financial obligations, primarily depends on the earnings and cash flows of the Utility and the ability of the Utility to distribute cash to PG&E Corporation (in the form of dividends and share repurchases) and reimburse PG&E Corporation for the Utility's share of applicable expenses. Before it can distribute cash to PG&E Corporation, the Utility must use its resources to satisfy its own obligations, including its obligation to serve customers, to pay principal and interest on outstanding debt, to pay preferred stock dividends, and meet its obligations to employees and creditors. The Utility's ability to pay common stock dividends is constrained by regulatory requirements, including that the Utility maintain its authorized capital structure with an average 52% equity component. Further, the CPUC could adopt the SED's financial recommendations made in its January 12, 2012 report on the San Bruno accident, including that the Utility "should target retained earnings towards safety improvements before providing dividends, especially if the Utility's ROE exceeds the level set in a GRC." PG&E Corporation's and the Utility's ability to pay dividends also could be affected by financial covenants contained in their respective credit agreements that require each company to maintain a ratio of consolidated total debt to consolidated capitalization of at most 65%. If the Utility is not able to make distributions to PG&E Corporation or to reimburse PG&E Corporation, PG&E Corporation's ability to meet its own obligations could be impaired and its ability to pay dividends could be restricted.

PG&E Corporation could be required to contribute capital to the Utility or be denied distributions from the Utility to the extent required by the CPUC's determination of the Utility's financial condition.

The CPUC imposed certain conditions when it approved the original formation of a holding company for the Utility, including an obligation by PG&E Corporation's Board of Directors to give "first priority" to 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. The CPUC later issued decisions adopting an expansive interpretation of PG&E Corporation's obligations under this condition, including the requirement that PG&E Corporation "infuse the Utility with all types of capital necessary for the Utility to fulfill its obligation to serve." The Utility's financial condition will be affected by the amount of costs the Utility incurs that it is not allowed to recover through rates, the amount of third-party losses it is unable to recover through insurance, and the amount of penalties the Utility incurs in connection with the pending investigations and future citations for self-reported violations. After considering these impacts, the CPUC's interpretation of PG&E Corporation's obligation under the first priority condition could require PG&E Corporation to infuse the Utility with significant capital in the future or could prevent distributions from the Utility to PG&E Corporation, or both, any of which could materially restrict PG&E Corporation's ability to pay principal and interest on its outstanding debt or pay its common stock dividend, meet other obligations, or execute its business strategy. Further, laws or regulations could be enacted or adopted in the future that could impose additional financial or other restrictions or requirements pertaining to transactions between a holding company and its regulated subsidiaries.

PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows will be affected by their ability to continue accessing the capital markets and by the terms of debt and equity financings.

The Utility relies on access to capital and credit markets as significant sources of liquidity to fund capital expenditures, pay principal and interest on its debt, provide collateral to support its natural gas and electricity procurement hedging contracts, and fund other operations requirements that are not satisfied by operating cash flows. See the discussion of the Utility's future financing needs above in "Liquidity and Financial Resources." PG&E Corporation relies on independent access to the capital and credit markets to fund its operations, make capital expenditures, and contribute equity to the Utility as needed to maintain the Utility's CPUC-authorized capital structure, if funds received from the Utility (in the form of dividends or share repurchases) are insufficient to meet such needs. Following the San Bruno accident, PG&E Corporation has issued a material amount of equity to fund its equity contributions to the Utility as the Utility has incurred costs and expenses it cannot recover through rates.

PG&E Corporation forecasts that it will continue to issue additional material amounts of equity as the Utility continues to incur costs that it cannot recover through rates, such as costs under its pipeline safety enhancement plan, to improve electricity and natural gas operations, and to pay penalties. PG&E Corporation may also be required to access the capital markets when the Utility is successful in selling long-term debt so that PG&E Corporation can contribute equity to the Utility as needed to maintain the Utility's authorized capital structure.

PG&E Corporation's and the Utility's ability to access the capital and credit markets and the costs and terms of available financing depend on many factors, including the amount of penalties imposed on the Utility in connection with the matters described above under "Natural Gas Maters;" changes in their credit ratings; changes in the federal or state regulatory environment affecting energy companies generally or PG&E Corporation and the Utility in particular; the overall health of the energy industry; volatility in electricity or natural gas prices; disruptions, uncertainty or volatility in the capital and credit markets; and general economic and market conditions. If PG&E Corporation's or the Utility's credit ratings were downgraded to below investment grade, their ability to access the capital and credit markets could be negatively affected and could result in higher borrowing costs, fewer financing options, including reduced access to the commercial paper market, additional collateral posting requirements, which in turn could affect liquidity and lead to an increased financing need.

If the Utility were unable to access the capital markets, it could be required to decrease or suspend dividends to PG&E Corporation. PG&E Corporation also would need to consider its alternatives, such as contributing capital to the Utility, to enable the Utility to fulfill its obligation to serve. If PG&E Corporation is required to contribute equity to the Utility in these circumstances, it would be required to seek these funds from the capital or credit markets. To maintain PG&E Corporation's dividend level in these circumstances, PG&E Corporation would be further required to access the capital or credit markets. PG&E Corporation may need to decrease or discontinue its common stock dividend if it is unable to access the capital or credit markets on reasonable terms.

PG&E Corporation
CONSOLIDATED STATEMENTS OF INCOME
(in millions, except per share amounts)

	Year ended December 31,		
	2012	2011	2010
Operating Revenues			
Electric	$ 12,019	$ 11,606	$ 10,645
Natural gas	3,021	3,350	3,196
Total operating revenues	**15,040**	**14,956**	**13,841**
Operating Expenses			
Cost of electricity	4,162	4,016	3,898
Cost of natural gas	861	1,317	1,291
Operating and maintenance	6,052	5,466	4,439
Depreciation, amortization, and decommissioning	2,272	2,215	1,905
Total operating expenses	**13,347**	**13,014**	**11,533**
Operating Income	1,693	1,942	2,308
Interest income	7	7	9
Interest expense	(703)	(700)	(684)
Other income, net	70	49	27
Income Before Income Taxes	**1,067**	**1,298**	**1,660**
Income tax provision	237	440	547
Net Income	**830**	**858**	**1,113**
Preferred stock dividend requirement of subsidiary	14	14	14
Income Available for Common Shareholders	**$ 816**	**$ 844**	**$ 1,099**
Weighted Average Common Shares Outstanding, Basic	**424**	**401**	**382**
Weighted Average Common Shares Outstanding, Diluted	**425**	**402**	**392**
Net Earnings Per Common Share, Basic	**$ 1.92**	**$ 2.10**	**$ 2.86**
Net Earnings Per Common Share, Diluted	**$ 1.92**	**$ 2.10**	**$ 2.82**
Dividends Declared Per Common Share	**$ 1.82**	**$ 1.82**	**$ 1.82**

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year ended December 31,		
(in millions)	2012	2011	2010
Net Income	**$ 830**	**$ 858**	**$ 1,113**
Other Comprehensive Income			
Pension and other postretirement benefit plans			
Unrecognized prior service credit (cost) (net of income tax of $14, $24, and $20 in 2012, 2011, and 2010, respectively)	17	36	(29)
Unrecognized net gain (loss) (net of income tax of $20, $452, and $73 in 2012 , 2011, and 2010, respectively)	31	(655)	(110)
Unrecognized net transition obligation (net of income tax of $8 in 2012, and $11 in 2011 and 2010, respectively)	16	15	15
Transfer to regulatory account (net of income tax of $30, $408, and $57 in 2012, 2011, and 2010, respectively)	44	593	82
Other (net of income tax of $3 in 2012)	4	—	—
Total other comprehensive income (loss)	**112**	**(11)**	**(42)**
Comprehensive Income	**942**	**847**	**1,071**
Preferred stock dividend requirement of subsidiary	**14**	**14**	**14**
Comprehensive Income Attributable to Common Shareholders	**$ 928**	**$ 833**	**$ 1,057**

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation
CONSOLIDATED BALANCE SHEETS
(in millions)

	Balance at December 31, 2012	Balance at December 31, 2011
ASSETS		
Current Assets		
Cash and cash equivalents	$ 401	$ 513
Restricted cash ($0 and $51 related to energy recovery bonds at December 31, 2012 and 2011, respectively)	330	380
Accounts receivable		
Customers (net of allowance for doubtful accounts of $87 and $81 at December 31, 2012 and 2011, respectively)	937	992
Accrued unbilled revenue	761	763
Regulatory balancing accounts	936	1,082
Other	365	839
Regulatory assets ($0 and $336 related to energy recovery bonds at December 31, 2012 and 2011, respectively)	564	1,090
Inventories		
Gas stored underground and fuel oil	135	159
Materials and supplies	309	261
Income taxes receivable	211	183
Other	172	218
Total current assets	**5,121**	**6,480**
Property, Plant, and Equipment		
Electric	39,701	35,851
Gas	12,571	11,931
Construction work in progress	1,894	1,770
Other	1	15
Total property, plant, and equipment	**54,167**	**49,567**
Accumulated depreciation	(16,644)	(15,912)
Net property, plant, and equipment	**37,523**	**33,655**
Other Noncurrent Assets		
Regulatory assets	6,809	6,506
Nuclear decommissioning trusts	2,161	2,041
Income taxes receivable	176	386
Other	659	682
Total other noncurrent assets	**9,805**	**9,615**
TOTAL ASSETS	**$ 52,449**	**$ 49,750**

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation
CONSOLIDATED BALANCE SHEETS
(in millions, except share amounts)

	Balance at December 31, 2012	Balance at December 31, 2011
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term borrowings	$ 492	$ 1,647
Long-term debt, classified as current	400	50
Energy recovery bonds, classified as current	—	423
Accounts payable		
Trade creditors	1,241	1,177
Disputed claims and customer refunds	157	673
Regulatory balancing accounts	634	374
Other	444	420
Interest payable	870	843
Income taxes payable	6	110
Deferred income taxes	—	196
Other	2,012	1,836
Total current liabilities	**6,256**	**7,749**
Noncurrent Liabilities		
Long-term debt	12,517	11,766
Regulatory liabilities	5,088	4,733
Pension and other postretirement benefits	3,575	3,396
Asset retirement obligations	2,919	1,609
Deferred income taxes	6,748	6,008
Other	2,020	2,136
Total noncurrent liabilities	**32,867**	**29,648**
Commitments and Contingencies (Note 15)		
Equity		
Shareholders' Equity		
Preferred stock	—	—
Common stock, no par value, authorized 800,000,000 shares, 430,718,293 shares outstanding at December 31, 2012 and 412,257,082 shares outstanding at December 31, 2011	8,428	7,602
Reinvested earnings	4,747	4,712
Accumulated other comprehensive loss	(101)	(213)
Total shareholders' equity	**13,074**	**12,101**
Noncontrolling Interest—Preferred Stock of Subsidiary	252	252
Total equity	**13,326**	**12,353**
TOTAL LIABILITIES AND EQUITY	**$ 52,449**	**$ 49,750**

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year ended December 31,		
	2012	2011	2010
Cash Flows from Operating Activities			
Net income	$ 830	$ 858	$ 1,113
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	2,272	2,215	1,905
Allowance for equity funds used during construction	(107)	(87)	(110)
Deferred income taxes and tax credits, net	648	544	756
Disallowed capital expenditures	353	—	36
Other	290	326	257
Effect of changes in operating assets and liabilities:			
Accounts receivable	(40)	(288)	(44)
Inventories	(24)	(63)	(43)
Accounts payable	(4)	65	48
Income taxes receivable/payable	(132)	(103)	(78)
Other current assets and liabilities	262	23	111
Regulatory assets, liabilities, and balancing accounts, net	291	(100)	(394)
Other noncurrent assets and liabilities	243	349	(351)
Net cash provided by operating activities	**4,882**	**3,739**	**3,206**
Cash Flows from Investing Activities			
Capital expenditures	(4,624)	(4,038)	(3,802)
Decrease in restricted cash	50	200	66
Proceeds from sales and maturities of nuclear decommissioning trust investments	1,133	1,928	1,405
Purchases of nuclear decommissioning trust investments	(1,189)	(1,963)	(1,456)
Other	104	(113)	(70)
Net cash used in investing activities	**(4,526)**	**(3,986)**	**(3,857)**
Cash Flows from Financing Activities			
Borrowings under revolving credit facilities	120	358	490
Repayments under revolving credit facilities	—	(358)	(490)
Net issuances (repayments) of commercial paper, net of discount of $3 in 2012, $4 in 2011, and $3 in 2010	(1,021)	782	267
Proceeds from issuance of short-term debt, net of issuance costs of $1 in 2010	—	250	249
Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $13 in 2012, $8 in 2011, and $23 in 2010	1,137	792	1,327
Short-term debt matured	(250)	(250)	(500)
Long-term debt matured or repurchased	(50)	(700)	(95)
Energy recovery bonds matured	(423)	(404)	(386)
Common stock issued	751	662	303
Common stock dividends paid	(746)	(704)	(662)
Other	14	41	(88)
Net cash provided by (used in) financing activities	**(468)**	**469**	**415**
Net change in cash and cash equivalents	**(112)**	**222**	**(236)**
Cash and cash equivalents at January 1	**513**	**291**	**527**
Cash and cash equivalents at December 31	**$ 401**	**$ 513**	**$ 291**
Supplemental disclosures of cash flow information			
Cash received (paid) for:			
Interest, net of amounts capitalized	$ (594)	$ (647)	$ (627)
Income taxes, net	114	(42)	(135)
Supplemental disclosures of noncash investing and financing activities			
Common stock dividends declared but not yet paid	$ 196	$ 188	$ 183
Capital expenditures financed through accounts payable	362	308	364
Noncash common stock issuances	22	24	265
Terminated capital leases	136	—	—

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation

CONSOLIDATED STATEMENTS OF EQUITY

(in millions, except share amounts)

	Common Stock Shares	Common Stock Amount	Reinvested Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity	Non controlling Interest— Preferred Stock of Subsidiary	Total Equity
Balance at December 31, 2009	**371,272,457**	**$ 6,280**	**$ 4,213**	**$ (160)**	**$ 10,333**	**$ 252**	**$ 10,585**
Net income	—	—	1,113	—	1,113	—	1,113
Other comprehensive loss	—	—	—	(42)	(42)	—	(42)
Common stock issued, net	23,954,748	568	—	—	568	—	568
Stock-based compensation amortization	—	34	—	—	34	—	34
Common stock dividends declared	—	—	(706)	—	(706)	—	(706)
Tax expense from employee stock plans	—	(4)	—	—	(4)	—	(4)
Preferred stock dividend requirement of subsidiary	—	—	(14)	—	(14)	—	(14)
Balance at December 31, 2010	**395,227,205**	**6,878**	**4,606**	**(202)**	**11,282**	**252**	**11,534**
Net income	—	—	858	—	858	—	858
Other comprehensive loss	—	—	—	(11)	(11)	—	(11)
Common stock issued, net	17,029,877	686	—	—	686	—	686
Stock-based compensation amortization	—	37	—	—	37	—	37
Common stock dividends declared	—	—	(738)	—	(738)	—	(738)
Tax benefit from employee stock plans	—	1	—	—	1	—	1
Preferred stock dividend requirement of subsidiary	—	—	(14)	—	(14)	—	(14)
Balance at December 31, 2011	**412,257,082**	**7,602**	**4,712**	**(213)**	**12,101**	**252**	**12,353**
Net income	—	—	830	—	830	—	830
Other comprehensive income	—	—	—	112	112	—	112
Common stock issued, net	18,461,211	773	—	—	773	—	773
Stock-based compensation amortization	—	52	—	—	52	—	52
Common stock dividends declared	—	—	(781)	—	(781)	—	(781)
Tax benefit from employee stock plans	—	1	—	—	1	—	1
Preferred stock dividend requirement of subsidiary	—	—	(14)	—	(14)	—	(14)
Balance at December 31, 2012	**430,718,293**	**$ 8,428**	**$ 4,747**	**$ (101)**	**$ 13,074**	**$ 252**	**$ 13,326**

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company
CONSOLIDATED STATEMENTS OF INCOME
(in millions)

	Year ended December 31,		
	2012	2011	2010
Operating Revenues			
Electric	$ 12,014	$ 11,601	$ 10,644
Natural gas	3,021	3,350	3,196
Total operating revenues	**15,035**	**14,951**	**13,840**
Operating Expenses			
Cost of electricity	4,162	4,016	3,898
Cost of natural gas	861	1,317	1,291
Operating and maintenance	6,045	5,459	4,432
Depreciation, amortization, and decommissioning	2,272	2,215	1,905
Total operating expenses	**13,340**	**13,007**	**11,526**
Operating Income	1,695	1,944	2,314
Interest income	6	5	9
Interest expense	(680)	(677)	(650)
Other income, net	88	53	22
Income Before Income Taxes	**1,109**	**1,325**	**1,695**
Income tax provision	298	480	574
Net Income	**811**	**845**	**1,121**
Preferred stock dividend requirement	14	14	14
Income Available for Common Stock	**$ 797**	**$ 831**	**$ 1,107**

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions)	Year ended December 31, 2012	2011	2010
Net Income	**$ 811**	**$ 845**	**$ 1,121**
Other Comprehensive Income			
Pension and other postretirement benefit plans			
Unrecognized prior service credit (cost) (net of income tax of $13, $24, and $21 in 2012, 2011, and 2010, respectively)	16	36	(30)
Unrecognized net gain (loss) (net of income tax of $22, $447, and $74 in 2012, 2011, and 2010, respectively)	33	(651)	(108)
Unrecognized net transition obligation (net of income tax of $8 in 2012, and $11 in 2011 and 2010, respectively)	16	15	15
Transfer to regulatory account (net of income tax of $30, $408, and $57 in 2012, 2011, and 2010, respectively)	44	593	82
Total other comprehensive income (loss)	**109**	**(7)**	**(41)**
Comprehensive Income	**$ 920**	**$ 838**	**$ 1,080**

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company
CONSOLIDATED BALANCE SHEETS
(in millions)

	Balance at December 31, 2012	2011
ASSETS		
Current Assets		
Cash and cash equivalents	$ 194	$ 304
Restricted cash ($0 and $51 related to energy recovery bonds at December 31, 2012 and 2011, respectively)	330	380
Accounts receivable		
Customers (net of allowance for doubtful accounts of $87 and $81 at December 31, 2012 and 2011, respectively)	937	992
Accrued unbilled revenue	761	763
Regulatory balancing accounts	936	1,082
Other	366	840
Regulatory assets ($0 and $336 related to energy recovery bonds at December 31, 2012 and 2011, respectively)	564	1,090
Inventories		
Gas stored underground and fuel oil	135	159
Materials and supplies	309	261
Income taxes receivable	186	242
Other	160	213
Total current assets	**4,878**	**6,326**
Property, Plant, and Equipment		
Electric	39,701	35,851
Gas	12,571	11,931
Construction work in progress	1,894	1,770
Total property, plant, and equipment	**54,166**	**49,552**
Accumulated depreciation	(16,643)	(15,898)
Net property, plant, and equipment	**37,523**	**33,654**
Other Noncurrent Assets		
Regulatory assets	6,809	6,506
Nuclear decommissioning trusts	2,161	2,041
Income taxes receivable	171	384
Other	381	331
Total other noncurrent assets	**9,522**	**9,262**
TOTAL ASSETS	**$ 51,923**	**$ 49,242**

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company

CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)

	Balance at December 31, 2012	Balance at December 31, 2011
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$ 372	$ 1,647
Long-term debt, classified as current	400	50
Energy recovery bonds, classified as current	—	423
Accounts payable		
Trade creditors	1,241	1,177
Disputed claims and customer refunds	157	673
Regulatory balancing accounts	634	374
Other	419	417
Interest payable	865	838
Income taxes payable	12	118
Deferred income taxes	—	199
Other	1,794	1,628
Total current liabilities	**5,894**	**7,544**
Noncurrent Liabilities		
Long-term debt	12,167	11,417
Regulatory liabilities	5,088	4,733
Pension and other postretirement benefits	3,497	3,325
Asset retirement obligations	2,919	1,609
Deferred income taxes	6,939	6,160
Other	1,959	2,070
Total noncurrent liabilities	**32,569**	**29,314**
Commitments and Contingencies (Note 15)		
Shareholders' Equity		
Preferred stock	258	258
Common stock, $5 par value, authorized 800,000,000 shares, 264,374,809 shares outstanding at December 31, 2012 and 2011	1,322	1,322
Additional paid-in capital	4,682	3,796
Reinvested earnings	7,291	7,210
Accumulated other comprehensive loss	(93)	(202)
Total shareholders' equity	**13,460**	**12,384**
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**$ 51,923**	**$ 49,242**

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year ended December 31,		
	2012	2011	2010
Cash Flows from Operating Activities			
Net income	$ 811	$ 845	$ 1,121
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	2,272	2,215	1,905
Allowance for equity funds used during construction	(107)	(87)	(110)
Deferred income taxes and tax credits, net	684	582	762
Disallowed capital expenditures	353	—	36
Other	236	289	221
Effect of changes in operating assets and liabilities:			
Accounts receivable	(40)	(227)	(105)
Inventories	(24)	(63)	(43)
Accounts payable	(26)	51	109
Income taxes receivable/payable	(50)	(192)	(58)
Other current assets and liabilities	272	36	123
Regulatory assets, liabilities, and balancing accounts, net	291	(100)	(394)
Other noncurrent assets and liabilities	256	414	(331)
Net cash provided by operating activities	**4,928**	**3,763**	**3,236**
Cash Flows from Investing Activities			
Capital expenditures	(4,624)	(4,038)	(3,802)
Decrease in restricted cash	50	200	66
Proceeds from sales and maturities of nuclear decommissioning trust investments	1,133	1,928	1,405
Purchases of nuclear decommissioning trust investments	(1,189)	(1,963)	(1,456)
Other	16	14	19
Net cash used in investing activities	**(4,614)**	**(3,859)**	**(3,768)**
Cash Flows from Financing Activities			
Borrowings under revolving credit facilities	—	208	400
Repayments under revolving credit facilities	—	(208)	(400)
Net issuances (repayments) of commercial paper, net of discount of $3 in 2012, $4 in 2011, and $3 in 2010	(1,021)	782	267
Proceeds from issuance of short-term debt, net of issuance costs of $1 in 2010	—	250	249
Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $13 in 2012, $8 in 2011, and $23 in 2010	1,137	792	1,327
Short-term debt matured	(250)	(250)	(500)
Long-term debt matured or repurchased	(50)	(700)	(95)
Energy recovery bonds matured	(423)	(404)	(386)
Preferred stock dividends paid	(14)	(14)	(14)
Common stock dividends paid	(716)	(716)	(716)
Equity contribution	885	555	190
Other	28	54	(73)
Net cash provided by (used in) financing activities	**(424)**	**349**	**249**
Net change in cash and cash equivalents	**(110)**	**253**	**(283)**
Cash and cash equivalents at January 1	**304**	**51**	**334**
Cash and cash equivalents at December 31	**$ 194**	**$ 304**	**$ 51**
Supplemental disclosures of cash flow information			
Cash received (paid) for:			
Interest, net of amounts capitalized	$ (574)	$ (627)	$ (595)
Income taxes, net	174	(50)	(171)
Supplemental disclosures of noncash investing and financing activities			
Capital expenditures financed through accounts payable	$ 362	$ 308	$ 364
Terminated capital leases	136	—	—

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(in millions)

	Preferred Stock	Common Stock	Additional Paid-in Capital	Reinvested Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
Balance at December 31, 2009	**$ 258**	**$ 1,322**	**$ 3,055**	**$ 6,704**	**$ (154)**	**$ 11,185**
Net income	—	—	—	1,121	—	1,121
Other comprehensive loss	—	—	—	—	(41)	(41)
Equity contribution	—	—	190	—	—	190
Tax expense from employee stock plans	—	—	(4)	—	—	(4)
Common stock dividend	—	—	—	(716)	—	(716)
Preferred stock dividend	—	—	—	(14)	—	(14)
Balance at December 31, 2010	**258**	**1,322**	**3,241**	**7,095**	**(195)**	**11,721**
Net income	—	—	—	845	—	845
Other comprehensive loss	—	—	—	—	(7)	(7)
Equity contribution	—	—	555	—	—	555
Common stock dividend	—	—	—	(716)	—	(716)
Preferred stock dividend	—	—	—	(14)	—	(14)
Balance at December 31, 2011	**258**	**1,322**	**3,796**	**7,210**	**(202)**	**12,384**
Net income	—	—	—	811	—	811
Other comprehensive income	—	—	—	—	109	109
Equity contribution	—	—	885	—	—	885
Tax benefit from employee stock plans	—	—	1	—	—	1
Common stock dividend	—	—	—	(716)	—	(716)
Preferred stock dividend	—	—	—	(14)	—	(14)
Balance at December 31, 2012	**$ 258**	**$ 1,322**	**$ 4,682**	**$ 7,291**	**$ (93)**	**$ 13,460**

See accompanying Notes to the Consolidated Financial Statements.

NOTE 1: ORGANIZATION AND BASIS OF PRESENTATION

PG&E Corporation is a holding company that conducts its business through Pacific Gas and Electric Company ("Utility"), a public utility operating in northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. The Utility is primarily regulated by the California Public Utilities Commission ("CPUC") and the Federal Energy Regulatory Commission ("FERC"). In addition, the Nuclear Regulatory Commission ("NRC") oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities. The Utility's accounts for electric and gas operations are maintained in accordance with the Uniform System of Accounts prescribed by the FERC.

This is a combined annual report of PG&E Corporation and the Utility. The Notes to the Consolidated Financial Statements apply to both PG&E Corporation and the Utility. PG&E Corporation's Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries. The Utility's Consolidated Financial Statements include the accounts of the Utility and its wholly owned and controlled subsidiaries. All intercompany transactions have been eliminated from the Consolidated Financial Statements. PG&E Corporation and the Utility operate in one segment.

The accompanying Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") for annual financial statements and in accordance with the instructions to Form 10-K and Regulation S-X promulgated by the Securities and Exchange Commission ("SEC"). The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions based on a wide range of factors, including future regulatory decisions and economic conditions, that are difficult to predict. Some of the more critical estimates and assumptions relate to the Utility's regulatory assets and liabilities, legal and regulatory contingencies, environmental remediation liabilities, asset retirement obligations ("ARO"), and pension and other postretirement benefit plans obligations. Management believes that its estimates and assumptions reflected in the Consolidated Financial Statements are appropriate and reasonable. Actual results could differ materially from those estimates.

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cash and Cash Equivalents

Cash and cash equivalents consist of cash and short-term, highly liquid investments with original maturities of three months or less. Cash equivalents are stated at fair value.

Restricted Cash

Restricted cash consists primarily of the Utility's cash held in escrow pending the resolution of the remaining disputed claims made by electricity suppliers in the Utility's proceeding under Chapter 11 of the U.S. Bankruptcy Code ("Chapter 11"). (See Note 13 below.)

Allowance for Doubtful Accounts Receivable

PG&E Corporation and the Utility recognize an allowance for doubtful accounts to record accounts receivable at estimated net realizable value. The allowance is determined based upon a variety of factors, including historical write-off experience, aging of receivables, current economic conditions, and assessment of customer collectability.

Inventories

Inventories are carried at weighted-average cost. Inventories include natural gas stored underground and materials and supplies. Natural gas stored underground represents purchases that are recorded to inventory and then expensed at weighted average cost when withdrawn and distributed to customers or used in electric generation. Materials and supplies are recorded to inventory when purchased and then expensed or capitalized to plant, as appropriate, when consumed or installed.

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Property, Plant, and Equipment

Property, plant, and equipment are reported at their original cost. These original costs include labor and materials, construction overhead, and allowance for funds used during construction ("AFUDC"). The Utility's estimated useful lives and balances of its property, plant, and equipment were as follows:

(in millions, except estimated useful lives)	Estimated Useful Lives (years)	Balance at December 31, 2012	Balance at December 31, 2011
Electricity generating facilities[1]	10 to 100	$ 8,253	$ 6,488
Electricity distribution facilities	10 to 55	23,767	22,395
Electricity transmission	10 to 70	7,681	6,968
Natural gas distribution facilities	20 to 53	8,257	7,832
Natural gas transportation and storage	5 to 48	4,314	4,099
Construction work in progress		1,894	1,770
Total property, plant, and equipment		**54,166**	**49,552**
Accumulated depreciation		(16,643)	(15,898)
Net property, plant, and equipment		**$ 37,523**	**$ 33,654**

(1) Balance includes nuclear fuel inventories. Stored nuclear fuel inventory is stated at weighted average cost. Nuclear fuel in the reactor is expensed as it is used based on the amount of energy output. (See Note 15 below.)

Depreciation

The Utility depreciates property, plant, and equipment using the composite, or group, method of depreciation, in which a single depreciation rate is applied to the gross investment in a particular class of property. This method approximates the straight line method of depreciation over the useful lives of property, plant, and equipment. The Utility's composite depreciation rates were 3.63% in 2012, 3.67% in 2011, and 3.38% in 2010.

The useful lives of the Utility's property, plant, and equipment are authorized by the CPUC and the FERC, and the depreciation expense is recovered through rates charged to customers. Depreciation expense includes a component for the original cost of assets and a component for estimated cost of future removal, net of any salvage value at retirement. Upon retirement, the original cost of the retired assets, net of salvage value, is charged against accumulated depreciation. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is charged to operating and maintenance expense as incurred.

AFUDC

AFUDC is a method used to compensate the Utility for the estimated cost of debt (i.e., interest) and equity funds used to finance regulated plant additions and is capitalized as part of the cost of construction. AFUDC is recoverable from customers through rates over the life of the related property once the property is placed in service. AFUDC related to the cost of debt is recorded as a reduction to interest expense. AFUDC related to the cost of equity is recorded in other income. The Utility recorded AFUDC of $49 million and $107 million during 2012, $40 million and $87 million during 2011, and $50 million and $110 million during 2010, related to debt and equity, respectively.

Regulation and Regulated Operations

As a regulated entity, the Utility's rates are designed to recover the costs of providing service. The Utility capitalizes and records, as regulatory assets, costs that would otherwise be charged to expense if it is probable that the incurred costs will be recovered in future rates. Regulatory assets are amortized over the future periods in which the costs are recovered. If costs expected to be incurred in the future are currently being recovered through rates,

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

the Utility records those expected future costs as regulatory liabilities. In addition, amounts that are probable of being credited or refunded to customers in the future are recorded as regulatory liabilities.

The Utility's ability to recover the revenue requirements that have been authorized by the CPUC in a general rate case ("GRC") and a gas transmission and storage rate case ("GT&S") does not depend on the volume of the Utility's sales of electricity and natural gas services. The Utility's recovery of a significant portion of its authorized revenue requirements through rates is independent, or "decoupled," from the volume of electricity and natural gas sales.

The Utility records differences between actual customer billings and the Utility's authorized revenue requirement, as well as differences between incurred costs and customer billings or authorized revenue meant to recover those costs. To the extent these differences are probable of recovery or refund, the Utility records a regulatory balancing account asset or liability, respectively and the differences do not have an impact on net income. For further discussion, see "Revenue Recognition" below.

To the extent that portions of the Utility's operations cease to be subject to cost-of-service rate regulation, or recovery is no longer probable as a result of changes in regulation or other reasons, the related regulatory assets and liabilities are written off.

Intangible Assets

Intangible assets primarily consist of hydroelectric facility licenses with terms ranging from 19 to 53 years. The gross carrying amount of intangible assets was $110 million at December 31, 2012 and $112 million at December 31, 2011. The accumulated amortization was $49 million at December 31, 2012 and $47 million at December 31, 2011.

The Utility's amortization expense related to intangible assets was $2 million in 2012, $3 million in 2011, and $4 million in 2010. The estimated annual amortization expense for 2013 through 2017 based on the December 31, 2012 intangible assets balance is $3 million. Intangible assets are recorded to other noncurrent assets—other in the Consolidated Balance Sheets.

Asset Retirement Obligations

PG&E Corporation and the Utility record an ARO at discounted fair value in the period in which the obligation is incurred if the discounted fair value can be reasonably estimated. In the same period, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. In each subsequent period, the ARO is accreted to its present value. PG&E Corporation and the Utility also record an ARO if a legal obligation to perform an asset removal exists and can be reasonably estimated, but performance is conditional upon a future event. The Utility recognizes timing differences between the recognition of costs and the costs recovered through the ratemaking process as regulatory assets or liabilities. (See Note 3 below.) The Utility has an ARO primarily for its nuclear generation facilities, certain fossil fuel-fired generation facilities, and gas transmission system assets.

Detailed studies of the cost to decommission the Utility's nuclear generation facilities are conducted every three years in conjunction with the Nuclear Decommissioning Cost Triennial Proceedings ("NDCTP") conducted by the CPUC. In December 2012, the Utility submitted its updated decommissioning cost estimate with the CPUC. The estimated undiscounted cost to decommission the Utility's nuclear power plants increased by $1.4 billion due to higher spent nuclear fuel disposal costs and an increase in the scope of work. The decommissioning cost estimates are based on the plant location and cost characteristics for the Utility's nuclear generation facilities. Actual decommissioning costs may vary from these estimates as a result of changes in assumptions such as decommissioning dates; regulatory requirements; technology; and costs of labor, materials, and equipment. The Utility recovers its revenue requirements for decommissioning costs from customers through a non-bypassable charge that the Utility expects will continue until those costs are fully recovered. A significant portion of the increase in decommissioning cost estimates is due to the need to develop on-site storage for spent nuclear fuel because the federal government has failed to meet its obligation to develop a permanent repository for the disposal of nuclear waste from nuclear facilities in the United States. The Utility expects that it will recover its future on-site storage costs from the federal government. The Utility already has recovered $266 million for spent nuclear fuel costs incurred through 2010. (See

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

"Spent Nuclear Fuel Storage Proceedings" in Note 15 below). Recovered amounts will be refunded to customers through rates. In its 2012 NDCTP application, the Utility requested that the CPUC issue a final decision by the end of 2013.

The estimated undiscounted nuclear decommissioning cost for the Utility's nuclear generation facilities was approximately $3.5 billion at December 31, 2012 and $2.3 billion at December 31, 2011, as filed in the 2012 and 2009 NDCTPs, respectively. In future dollars, the estimated nuclear decommissioning cost is approximately $6.1 billion and $4.4 billion, respectively. These estimates are based on the 2012 and 2009 decommissioning cost studies, respectively, and are prepared in accordance with CPUC requirements. The estimated nuclear decommissioning cost in future dollars is discounted for GAAP purposes and recognized as an ARO on the Consolidated Balance Sheets. The total nuclear decommissioning obligation accrued in accordance with GAAP was $2.5 billion at December 31, 2012 and $1.2 billion at December 31, 2011.

A reconciliation of the changes in the ARO liability is as follows:

(in millions)	
ARO liability at December 31, 2010	$ 1,586
Revision in estimated cash flows	10
Accretion	100
Liabilities settled	(87)
ARO liability at December 31, 2011	**1,609**
Revision in estimated cash flows	1,301
Accretion	101
Liabilities settled	(92)
ARO liability at December 31, 2012	**$ 2,919**

The Utility has identified the following AROs for which a reasonable estimate of fair value could not be made. As a result, the Utility has not recorded a liability related to these AROs:

- *Restoration of land to its pre-use condition under the terms of certain land rights agreements.* Land rights will be maintained for the foreseeable future, and therefore, the Utility cannot reasonably estimate the settlement date(s) or range of settlement dates for the obligations associated with these assets;
- *Removal and proper disposal of lead-based paint contained in some Utility facilities.* The Utility does not have information available that specifies which facilities contain lead-based paint and, therefore, cannot reasonably estimate the settlement date(s) associated with the obligations; and
- *Removal of certain communications equipment from leased property, and retirement activities associated with substation and certain hydroelectric facilities.* The Utility will maintain and continue to operate its hydroelectric facilities until the operation of a facility becomes uneconomical. The operation of the majority of the Utility's hydroelectric facilities is currently, and for the foreseeable future, expected to be economically beneficial. Therefore, the settlement date(s) cannot be reasonably estimated at this time.

Disallowance of Plant Costs

PG&E Corporation and the Utility record a charge to net income when it is both probable that costs incurred or projected to be incurred for recently completed plant will not be recoverable through rates charged to customers and the amount of disallowance can be reasonably estimated. During 2012, the Utility recorded a $353 million charge to net income for capital expenditures incurred in connection with its pipeline safety enhancement plan that were either specifically disallowed or that are forecasted to exceed the CPUC's authorized levels. (See "CPUC Gas Safety Rulemaking Proceeding" in Note 15 below). No material disallowance losses were recorded in 2011 and $36 million in disallowance losses were recorded in 2010.

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Gains and Losses on Debt Extinguishments

Gains and losses on debt extinguishments associated with regulated operations are deferred and amortized over the remaining original amortization period of the debt reacquired, consistent with recovery of costs through regulated rates. PG&E Corporation and the Utility recorded unamortized loss on debt extinguishments, net of gain, of $163 million and $186 million at December 31, 2012 and 2011, respectively. The amortization expense related to this loss was $23 million in 2012, $18 million in 2011, and $23 million in 2010. Deferred gains and losses on debt extinguishments are recorded to current assets—regulatory assets and other noncurrent assets—regulatory assets in the Consolidated Balance Sheets.

Gains and losses on debt extinguishments associated with unregulated operations are fully recognized at the time such debt is reacquired and are reported as a component of interest expense.

Revenue Recognition

The Utility recognizes revenues as electricity and natural gas services are delivered, and includes amounts for services rendered but not yet billed at the end of the period.

The CPUC authorizes most of the Utility's revenue requirements in its GRC and its GT&S, which generally occur every three years. The Utility's ability to recover revenue requirements authorized by the CPUC in these rates cases is independent, or "decoupled" from the volume of the Utility's sales of electricity and natural gas services. The Utility recognizes revenues once they have been authorized for rate recovery, amounts are objectively determinable and probable of recovery, and amounts will be collected within 24 months. Generally, the revenue recognition criteria are met ratably over the year. (See Note 3 below.)

The CPUC also has authorized the Utility to collect additional revenue requirements to recover costs that the Utility has been authorized to pass on to customers, including costs to purchase electricity and natural gas; and to fund public purpose, demand response, and customer energy efficiency programs. Generally, the revenue recognition criteria for pass-through costs billed to customers are met at the time the costs are incurred.

The FERC authorizes the Utility's revenue requirements in annual transmission owner rate cases. The Utility's ability to recover revenue requirements authorized by the FERC is dependent on the volume of the Utility's electricity sales, and revenue is recognized only for amounts billed and unbilled.

The Utility's revenues and net income also are affected by incentive ratemaking mechanisms that adjust rates depending on the extent to which the Utility meets certain performance criteria.

Income Taxes

PG&E Corporation and the Utility use the liability method of accounting for income taxes. Income tax provision includes current and deferred income taxes resulting from operations during the year. PG&E Corporation and the Utility estimate current period actual tax expense in addition to calculating deferred tax assets and liabilities. Deferred tax assets and liabilities result from temporary tax and accounting timing differences, such as depreciation, and are reported within the PG&E Corporation and Utility's balance sheets. (See Note 9 below.)

PG&E Corporation and the Utility recognize a tax benefit if it is more likely than not that a tax position taken or expected to be taken in a tax return will be sustained upon examination by taxing authorities based on the merits of the position. The tax benefit recognized in the financial statements is measured based on the largest amount of benefit that is greater than 50% likely of being realized upon settlement. As such, the difference between a tax position taken or expected to be taken in a tax return in future periods and the benefit recognized and measured pursuant to this guidance represents an unrecognized tax benefit.

Investment tax credits are deferred and amortized to income over time. The Utility amortizes its investment tax credits over the life of the related property in accordance with regulatory treatment. PG&E Corporation amortizes its investment tax credits over the projected investment recovery period.

PG&E Corporation files a consolidated U.S. federal income tax return that includes domestic subsidiaries in which its ownership is 80% or more. In addition, PG&E Corporation files a combined state income tax return in California. PG&E Corporation and the Utility are parties to a tax-sharing agreement under which the Utility determines its income tax provision (benefit) on a stand-alone basis.

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Nuclear Decommissioning Trusts

The Utility's nuclear generation facilities consist of two units at Diablo Canyon and the retired facility at Humboldt Bay. Nuclear decommissioning requires the safe removal of a nuclear generation facility 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's nuclear decommissioning costs are recovered from customers through rates and are held in trusts until authorized for release by the CPUC.

The Utility classifies its investments held in the nuclear decommissioning trusts as "available-for-sale." Since the Utility's nuclear decommissioning trust assets are managed by external investment managers, the Utility does not have the ability to sell its investments at its discretion. Therefore, all unrealized losses are considered other-than-temporary impairments. Gains or losses on the nuclear decommissioning trust investments are refundable or recoverable, respectively, from customers through rates. Therefore, trust earnings are deferred and included in the regulatory liability for recoveries in excess of the ARO. There is no impact on the Utility's earnings or accumulated other comprehensive income. The cost of debt and equity securities sold is determined by specific identification.

Accounting for Derivatives

Derivative instruments are recorded in PG&E Corporation's and the Utility's Consolidated Balance Sheets at fair value, unless they qualify for the normal purchase and sales exception. Changes in the fair value of derivative instruments are recorded in earnings or, to the extent that they are probable of future recovery through regulated rates, are deferred and recorded in regulatory accounts.

The normal purchase and sales exception to derivative accounting requires, among other things, physical delivery of quantities expected to be used or sold over a reasonable period in the normal course of business. Transactions which qualify for the normal purchase and sales exception are not reflected in the Consolidated Balance Sheets at fair value, but are accounted for under the accrual method of accounting. Therefore, expenses are recognized as incurred.

PG&E Corporation and the Utility offset cash collateral paid or cash collateral received against the fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement where the right of offset and the intention to offset exist. (See Note 10 below.)

Fair Value Measurements

PG&E Corporation and the Utility determine the fair value of certain assets and liabilities based on assumptions that market participants would use in pricing the assets or liabilities. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, or the "exit price." PG&E Corporation and the Utility utilize a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value and give precedence to observable inputs in determining fair value. An instrument's level within the hierarchy is based on the lowest level of any significant input to the fair value measurement. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). (See Note 11 below.)

Variable Interest Entities

PG&E Corporation and the Utility are required to consolidate the financial results of any entities that they control. In most cases, control can be determined based on majority ownership or voting interests. However, there are certain entities known as variable interest entities ("VIEs") for which control is difficult to discern based on ownership or voting interests alone. A VIE is an entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support from other parties, or whose equity investors lack any characteristics of a controlling financial interest. An enterprise has a controlling financial interest in a VIE if it has the obligation to absorb expected losses or the right to receive expected gains that could potentially be significant to the VIE and if it has any decision-making rights associated with the activities that are most significant to the VIE's

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

economic performance, including the power to design the VIE. An enterprise that has a controlling financial interest in a VIE is known as the VIE's primary beneficiary and is required to consolidate the VIE.

In determining whether consolidation of a particular entity is required, PG&E Corporation and the Utility first evaluate whether the entity is a VIE. If the entity is a VIE, PG&E Corporation and the Utility use a qualitative approach to determine if either is the primary beneficiary of the VIE.

Some of the counterparties to the Utility's power purchase agreements are considered VIEs. Each of these VIEs was designed to own a power plant that would generate electricity for sale to the Utility subject to the terms of a power purchase agreement. In determining whether the Utility is the primary beneficiary of any of these VIEs, it assesses whether it absorbs any of the VIE's expected losses or receives any portion of the VIE's expected residual returns under the terms of the power purchase agreement. This assessment includes an evaluation of how the risks and rewards associated with the power plant's activities are absorbed by variable interest holders, as well as an analysis of the variability in the VIE's gross margin and the impact of the power purchase agreement on the gross margin. Under each of these power purchase agreements, the Utility is obligated to purchase electricity or capacity, or both, from the VIE. The Utility does not provide any other support to these VIEs, and the Utility's financial exposure is limited to the amount it pays for delivered electricity and capacity. (See Note 15 below.) The Utility does not have any decision-making rights associated with the design of any VIEs, nor does the Utility have the power to direct the activities that are most significant to the economic performance of any VIEs such as dispatch rights, operating and maintenance activities, or re-marketing activities of the power plant after the termination of any VIE's power purchase agreement with the Utility. Since the Utility was not the primary beneficiary of any of these VIEs at December 31, 2012, it did not consolidate any of them.

The Utility continued to consolidate the financial results of PG&E Energy Recovery Funding LLC ("PERF"), a VIE, at December 31, 2012, since the Utility is the primary beneficiary of PERF. PERF was formed in 2005 as a wholly owned subsidiary of the Utility to issue energy recovery bonds ("ERBs") in connection with the settlement agreement entered into among PG&E Corporation, the Utility, and the CPUC in 2003 to resolve the Utility's proceeding under Chapter 11 ("Chapter 11 Settlement Agreement"). The Utility has a controlling financial interest in PERF since the Utility is exposed to PERF's losses and returns through the Utility's 100% equity investment in PERF and the Utility was involved in the design of PERF, which was an activity that was significant to PERF's economic performance. PERF is expected to be dissolved in 2013. (See Note 5 below.) While PERF is a wholly owned consolidated subsidiary of the Utility, it is legally separate from the Utility. The assets (including the recovery property) of PERF are not available to creditors of the Utility of PG&E Corporation, and the recovery property is not legally an asset of the Utility or PG&E Corporation.

At December 31, 2012, PG&E Corporation affiliates had entered into four tax equity agreements to fund residential and commercial retail solar energy installations with two privately held companies that are considered VIEs. Under these agreements, PG&E Corporation has agreed to provide lease payments and investment contributions of up to $396 million to these companies in exchange for the right to receive benefits from local rebates, federal grants, and a share of the customer payments made to these companies. The majority of these amounts are recorded in other noncurrent assets—other in PG&E Corporation's Consolidated Balance Sheets. At December 31, 2012, PG&E Corporation had made total payments of $361 million under these agreements and received $228 million in benefits and customer payments. In determining whether PG&E Corporation is the primary beneficiary of any of these VIEs, PG&E Corporation assesses which of the variable interest holders has control over these companies' significant economic activities, such as the design of the companies, vendor selection, construction, customer selection, and re-marketing activities after the termination of customer leases. PG&E Corporation determined that these companies control these activities, while its financial exposure from these agreements is generally limited to its lease payments and investment contributions to these companies. Since PG&E Corporation was not the primary beneficiary of any of these VIEs at December 31, 2012, it did not consolidate any of them.

NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

Regulatory Assets

Current Regulatory Assets

At December 31, 2012 and 2011, the Utility had current regulatory assets of $564 million and $1,090 million, respectively. At December 31, 2012, current regulatory assets consisted primarily of $230 million of the current portion of the price risk management regulatory asset, $62 million of the current portion of the Utility's retained generation regulatory assets, and $54 million of the current portion of the electromechanical meters regulatory asset, each of which is expected to be recovered over the next year. (See "Long-Term Regulatory Assets" below.)

Long-Term Regulatory Assets

Long-term regulatory assets are composed of the following:

	Balance at December 31,	
(in millions)	**2012**	**2011**
Pension benefits	$ 3,275	$ 2,899
Deferred income taxes	1,627	1,444
Utility retained generation	552	613
Environmental compliance costs	604	520
Price risk management	210	339
Electromechanical meters	194	247
Unamortized loss, net of gain, on reacquired debt	141	163
Other	206	281
Total long-term regulatory assets	**$ 6,809**	**$ 6,506**

The regulatory asset for pension benefits represents the cumulative differences between amounts recognized for ratemaking purposes and amounts recognized in accordance with GAAP and also includes amounts that otherwise would be recorded to accumulated other comprehensive loss in the Consolidated Balance Sheets. (See Note 12 below.)

The regulatory asset for deferred income taxes represents deferred income tax benefits previously passed through to customers. The CPUC requires the Utility to pass through certain tax benefits to customers by reducing rates, thereby ignoring the effect of deferred taxes. Based on current regulatory ratemaking and income tax laws, the Utility expects to recover the regulatory asset over the average plant depreciation lives of one to 45 years.

In connection with the Chapter 11 Settlement Agreement, the CPUC authorized the Utility to recover $1.2 billion of costs related to the Utility's retained generation assets. The individual components of these regulatory assets are being amortized over the respective lives of the underlying generation facilities, consistent with the period over which the related revenues are recognized. The weighted average remaining life of the assets is 12 years.

The regulatory asset for environmental compliance costs represents the cumulative differences between amounts recognized for ratemaking purposes and amounts recognized in accordance with GAAP. The Utility expects to recover these costs over the next 32 years, as the environmental compliance work is performed. (See Note 15 below.)

The regulatory asset for price risk management represents the unrealized losses related to price risk management derivative instruments expected to be recovered as they are realized over the next 10 years as part of the Utility's energy procurement costs. (See Note 10 below.)

The regulatory asset for electromechanical meters represents the expected future recovery of the net book value of electromechanical meters that were replaced with SmartMeter™ devices. The Utility expects to recover the regulatory asset over the next four years.

The regulatory asset for unamortized loss, net of gain, on reacquired debt represents the expected future recovery of costs related to debt reacquired or redeemed prior to maturity with associated discount and debt issuance

NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS (Continued)

costs. These costs are expected to be recovered over the next 14 years, which is the remaining amortization period of the reacquired debt.

In general, the Utility does not earn a return on regulatory assets if the related costs do not accrue interest. Accordingly, the Utility earns a return only on its regulatory assets for retained generation, regulatory assets for electromechanical meters, and regulatory assets for unamortized loss, net of gain, on reacquired debt.

Regulatory Liabilities

Current Regulatory Liabilities

At December 31, 2012 and 2011, the Utility had current regulatory liabilities of $337 million and $161 million, respectively, consisting of amounts that it expects to refund to customers over the next 12 months. At December 31, 2012 current regulatory liabilities primarily included $158 million of ERB over collections, $84 million of proceeds from a greenhouse gas ("GHG") emission auction to comply with California Air Resources Board requirements, and electricity supplier settlement agreements of $50 million (See Note 13 below). Current regulatory liabilities are included within current liabilities—other in the Consolidated Balance Sheets.

Long-Term Regulatory Liabilities

Long-term regulatory liabilities are composed of the following:

	Balance at December 31,	
(in millions)	**2012**	**2011**
Cost of removal obligations	$ 3,625	$ 3,460
Recoveries in excess of AROs	620	611
Public purpose programs	590	499
Other	253	163
Total long-term regulatory liabilities	**$ 5,088**	**$ 4,733**

The regulatory liability for cost of removal obligations represents the cumulative differences between asset removal costs recorded and amounts collected in rates for expected asset removal costs.

The regulatory liability for recoveries in excess of AROs represents the cumulative differences between ARO expenses and amounts collected in rates primarily for the decommissioning of the Utility's nuclear generation facilities. Decommissioning costs recovered through rates are primarily placed in nuclear decommissioning trusts. This regulatory liability also represents the deferral of realized and unrealized gains and losses on the nuclear decommissioning trust investments. (See Note 11 below.)

The regulatory liability for public purpose programs represents amounts received from customers designated for public purpose program costs expected to be incurred beyond the next 12 months, primarily related to energy efficiency programs designed to encourage the manufacture, design, distribution, and customer use of energy efficient appliances and other energy-using products, the California Solar Initiative program to promote the use of solar energy in homes and commercial, industrial, and agricultural properties, and the Self-Generation Incentive program to promote distributed generation technologies installed on the customer's side of the utility meter.

Regulatory Balancing Accounts

The Utility's current regulatory balancing accounts represent the amounts expected to be collected from or refunded to customers through authorized rate adjustments over the next 12 months. Regulatory balancing accounts that the Utility does not expect to collect or refund over the next 12 months are included in other noncurrent assets—regulatory assets or noncurrent liabilities—regulatory liabilities, respectively, in the Consolidated Balance Sheets.

NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS (Continued)

Current Regulatory Balancing Accounts, Net

	Receivable (Payable) Balance at December 31,	
(in millions)	**2012**	**2011**
Distribution revenue adjustment mechanism	$ 219	$ 223
Utility generation	117	241
Hazardous substance	56	57
Public purpose programs	(83)	97
Gas fixed cost	44	16
Energy recovery bonds	(43)	(105)
Energy procurement	77	(48)
Department of Energy Settlement	(250)	—
Other	165	227
Total regulatory balancing accounts, net	**$ 302**	**$ 708**

The distribution revenue adjustment mechanism balancing account is used to record and recover the authorized electric distribution revenue requirements and certain other electric distribution-related authorized costs. The utility generation balancing account is used to record and recover the authorized revenue requirements associated with Utility-owned electric generation, including capital costs and related non-fuel operating and maintenance expenses. The recovery of these revenue requirements is decoupled from the volume of sales; therefore, the Utility recognizes revenue evenly over the year, even though the level of cash collected from customers fluctuates depending on the volume of electricity sales. During the colder months of winter, there is generally an under-collection in these balancing accounts due to a lower volume of electricity sales and lower rates. During the warmer months of summer, there is generally an over-collection due to a higher volume of electricity sales and higher rates.

The hazardous substance balancing accounts are used to record and recover hazardous substance remediation costs that are eligible for recovery through a CPUC-approved ratemaking mechanism. (See Note 15 below.)

The public purpose programs balancing accounts are primarily used to record and recover the authorized revenue requirements associated with administering public purpose programs, as well as incentive awards earned by the Utility for achieving regulatory targets in the customer energy efficiency programs. The public purpose programs primarily consist of energy efficiency programs, low-income energy efficiency programs, demand response programs, research, development, and demonstration programs, and renewable energy programs.

The gas fixed-cost balancing account is used to record and recover authorized gas distribution revenue requirements and certain other authorized gas distribution-related costs. Similar to the utility generation and the distribution revenue adjustment mechanism balancing accounts discussed above, the recovery of these revenue requirements is decoupled from the volume of sales; therefore, the Utility recognizes revenue evenly over the year, even though the level of cash collected from customers fluctuates depending on the volume of gas sales. During the colder months of winter, there is generally an over-collection in this balancing account primarily due to higher natural gas sales. During the warmer months of summer, there is generally an under-collection primarily due to lower natural gas sales.

The ERBs balancing account is used to record and refund to customers the net refunds, claim offsets, and other credits received by the Utility from electricity suppliers related to Chapter 11 disputed claims and to record and recover authorized ERB servicing costs. (See Note 13 below.)

The Utility is generally authorized to recover 100% of its prudently incurred electric energy procurement costs. The Utility tracks energy procurement costs in balancing accounts and files annual forecasts of energy procurement costs that it expects to incur over the following year. The Utility's energy rates are set to recover such expected costs.

NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS (Continued)

The Department of Energy balancing account is used to record and refund to customers the amounts received from the U.S. Department of Energy ("DOE") during 2012 for a settlement agreement related to spent nuclear fuel storage costs incurred by the Utility.

NOTE 4: DEBT

Long-Term Debt

The following table summarizes PG&E Corporation's and the Utility's long-term debt:

(in millions)	December 31, 2012	December 31, 2011
PG&E Corporation		
Senior notes, 5.75%, due 2014	350	350
Unamortized discount	—	(1)
Total senior notes	**350**	**349**
Total PG&E Corporation long-term debt	**350**	**349**
Utility		
Senior notes:		
6.25% due 2013	400	400
4.80% due 2014	1,000	1,000
5.625% due 2017	700	700
8.25% due 2018	800	800
3.50% due 2020	800	800
4.25% due 2021	300	300
3.25% due 2021	250	250
2.45% due 2022	400	—
6.05% due 2034	3,000	3,000
5.80% due 2037	950	950
6.35% due 2038	400	400
6.25% due 2039	550	550
5.40% due 2040	800	800
4.50% due 2041	250	250
4.45% due 2042	400	—
3.75% due 2042	350	—
Less: current portion	(400)	—
Unamortized discount, net of premium	(51)	(51)
Total senior notes, net of current portion	**10,899**	**10,149**
Pollution control bonds:		
Series 1996 C, E, F, 1997 B, variable rates(1), due 2026(2)	614	614
Series 2004 A-D, 4.75%, due 2023(3)	345	345
Series 2009 A-D, variable rates(4), due 2016 and 2026(5)	309	309
Series 2010 E, 2.25%, due 2026(6)	—	50
Less: current portion	—	(50)
Total pollution control bonds	**1,268**	**1,268**
Total Utility long-term debt, net of current portion	**12,167**	**11,417**
Total consolidated long-term debt, net of current portion	**$ 12,517**	**$ 11,766**

(1) At December 31, 2012, interest rates on these bonds and the related loans ranged from 0.10% to 0.14%.

NOTE 4: DEBT (Continued)

(2) Each series of these bonds is supported by a separate letter of credit that expires on May 31, 2016. Although the stated maturity date is 2026, each series will remain outstanding only if the Utility extends or replaces the letter of credit related to the series or otherwise obtains consent from the issuer to the continuation of the series without a credit facility.

(3) The Utility has obtained credit support from an insurance company for these bonds.

(4) At December 31, 2012, interest rates on these bonds and the related loans ranged from 0.05% to 0.11%.

(5) Each series of these bonds is supported by a separate direct-pay letter of credit that expires on May 31, 2016. Subject to certain requirements, the Utility may choose not to provide a credit facility without issuer consent.

(6) These bonds bore interest at 2.25% per year through April 1, 2012; and were subject to mandatory tender on April 2, 2012. The Utility repurchased these bonds on April 2, 2012 and continues to hold them.

Pollution Control Bonds

The California Pollution Control Financing Authority and the California Infrastructure and Economic Development Bank have issued various series of fixed rate and multi-modal tax-exempt pollution control bonds for the benefit of the Utility. All of the pollution control bonds were used to finance or refinance pollution control and sewage and solid waste disposal facilities at the Geysers geothermal power plant or at the Utility's Diablo Canyon nuclear power plant and were issued as "exempt facility bonds" within the meaning of the Internal Revenue Code of 1954 ("Code"), as amended. In 1999, the Utility sold the Geysers geothermal power plant to Geysers Power Company, LLC pursuant to purchase and sale agreements stating that Geysers Power Company, LLC will use the bond-financed facilities solely as pollution control facilities. The Utility has no knowledge that Geysers Power Company, LLC intends to cease using the bond-financed facilities solely as pollution control facilities.

Repayment Schedule

PG&E Corporation's and the Utility's combined aggregate debt principal repayment amounts at December 31, 2012 are reflected in the table below:

(in millions, except interest rates)	2013	2014	2015	2016	2017	Thereafter	Total
PG&E Corporation							
Average fixed interest rate	—	5.75%	—	—	—	—	5.75%
Fixed rate obligations	$ —	$ 350	$ —	$ —	$ —	$ —	$ 350
Utility							
Average fixed interest rate	6.25%	4.80%	—	—	5.63%	5.45%	5.43%
Fixed rate obligations	$ 400	$ 1,000	$ —	$ —	$ 700	$ 9,595	$ 11,695
Variable interest rate as of December 31, 2012	—	—	—	0.11%	—	—	0.11%
Variable rate obligations	$ —	$ —	$ —	$ 923(1)	$ —	$ —	$ 923
Total consolidated debt	**$ 400**	**$ 1,350**	**$ —**	**$ 923**	**$ 700**	**$ 9,595**	**$ 12,968**

(1) These bonds, due in 2016 and 2026, are backed by letters of credit that expire on May 31, 2016.

Short-term Borrowings

The following table summarizes PG&E Corporation's and the Utility's outstanding borrowings on its revolving credit facilities and commercial paper program at December 31, 2012:

(in millions)	Termination Date	Facility Limit	Letters of Credit Outstanding	Borrowings	Commercial Paper	Facility Availability
PG&E Corporation	May 2016	$ 300(1)	$ —	$ 120	$ —	$ 180
Utility	May 2016	3,000(2)	266	—	370(3)	2,364(3)
Total revolving credit facilities		**$ 3,300**	**$ 266**	**$ 120**	**$ 370**	**$ 2,544**

(1) Includes a $100 million sublimit for letters of credit and a $100 million commitment for loans that are made available on a same-day basis and are repayable in full within 7 days.

NOTE 4: DEBT (Continued)

(2) Includes a $1.0 billion sublimit for letters of credit and a $300 million commitment for loans that are made available on a same-day basis and are repayable in full within 7 days.

(3) The Utility treats the amount of its outstanding commercial paper as a reduction to the amount available under its revolving credit facility.

For 2012, the average outstanding borrowings on PG&E Corporation's revolving credit facility was $21 million and the maximum outstanding balance during the year was $120 million. For 2012, the Utility's average outstanding commercial paper balance was $665 million and the maximum outstanding balance during the year was $1.4 billion.

Revolving Credit Facilities

PG&E Corporation has a $300 million revolving credit facility with a syndicate of lenders. The Utility has a $3.0 billion revolving credit facility with a syndicate of lenders. The revolving credit facilities have terms of five years and all amounts are due and payable on the facilities' termination date, May 31, 2016. At PG&E Corporation's and the Utility's request and at the sole discretion of each lender, the facilities may be extended for additional periods. The revolving credit facilities may be used for working capital and other corporate purposes. The Utility's revolving credit facility may also be used for the repayment of commercial paper.

Provided certain conditions are met, PG&E Corporation and the Utility have the right to increase, in one or more requests, given not more frequently than once a year, the aggregate lenders' commitments under the revolving credit facilities by up to $100 million and $500 million, respectively, in the aggregate for all such increases.

Borrowings under the revolving credit facilities (other than swingline loans) bear interest based, at PG&E Corporation's and the Utility's election, on (1) a London Interbank Offered Rate ("LIBOR") plus an applicable margin or (2) the base rate plus an applicable margin. The base rate will equal the higher of the following: the administrative agent's announced base rate, 0.5% above the federal funds rate, or the one-month LIBOR plus an applicable margin. Interest is payable quarterly in arrears, or earlier for loans with shorter interest periods. PG&E Corporation and the Utility also will pay a facility fee on the total commitments of the lenders under the revolving credit facilities. The applicable margins and the facility fees will be based on PG&E Corporation's and the Utility's senior unsecured debt ratings issued by Standard & Poor's Rating Services and Moody's Investor Service. Facility fees are payable quarterly in arrears.

The revolving credit facilities include usual and customary covenants for revolving credit facilities of this type, including covenants limiting liens to those permitted under PG&E Corporation's and the Utility's senior note indentures, mergers, sales of all or substantially all of PG&E Corporation's and the Utility's assets, and other fundamental changes. In addition, the revolving credit facilities require that PG&E Corporation and the Utility maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% as of the end of each fiscal quarter. PG&E Corporation's revolving credit facility agreement also requires that PG&E Corporation own, directly or indirectly, at least 80% of the common stock and at least 70% of the voting capital stock of the Utility. At December 31, 2012, PG&E Corporation and the Utility were in compliance with all covenants under their respective revolving credit facilities.

Commercial Paper Program

The Utility has a $1.75 billion commercial paper program, the borrowings from which are used primarily to fund temporary financing needs. Liquidity support for these borrowings is provided by available capacity under the Utility's revolving credit facilities, as described above. The commercial paper may have maturities up to 365 days and ranks equally with the Utility's other unsubordinated and unsecured indebtedness. Commercial paper notes are sold at an interest rate dictated by the market at the time of issuance. At December 31, 2012, the average yield on outstanding commercial paper was 0.36%.

Other Short-term Borrowings

In November 2011, the Utility issued $250 million principal amount of Floating Rate Senior Notes which were due and repaid in November 2012. For the years ended December 31, 2012 and 2011, the average interest rate on the Floating Rate Senior Notes was 0.92% and 0.94%, respectively.

NOTE 5: ENERGY RECOVERY BONDS

In 2005, PERF issued two series of ERBs. The proceeds of the ERBs were used by PERF to purchase from the Utility the right known as "recovery property" to be paid a specific amount from a dedicated rate component. The first series of ERBs included five classes aggregating to a $1.9 billion principal amount. The proceeds of the first series of ERBs were paid by PERF to the Utility and used by the Utility to refinance the remaining unamortized after-tax balance of the regulatory asset established under the Chapter 11 Settlement Agreement. The second series of ERBs included three classes aggregating to an $844 million principal amount. The proceeds of the second series of ERBs were paid by PERF to the Utility and used to pre-fund the Utility's tax liability for bond-related charges collected from customers.

At December 31, 2011, the total amount of ERB principal outstanding was $423 million. The ERBs were paid in full when the final class matured on December 25, 2012.

NOTE 6: COMMON STOCK AND SHARE-BASED COMPENSATION

PG&E Corporation

PG&E Corporation had 430,718,293 shares of common stock outstanding at December 31, 2012. During 2012, PG&E Corporation issued 6,803,101 shares of its common stock under its 401(k) plan, its Dividend Reinvestment and Stock Purchase Plan, and its share-based compensation plans, generating $263 million of cash.

In November 2011, PG&E Corporation entered into an Equity Distribution Agreement providing for the sale of PG&E common stock having an aggregate gross sales price of up to $400 million. Sales of the shares are made by means of ordinary brokers' transactions on the New York Stock Exchange, or in such other transactions as agreed upon by PG&E Corporation and the sales agents and in conformance with applicable securities laws. During 2012, PG&E Corporation sold 5,446,760 shares of its common stock under the Equity Distribution Agreement for cash proceeds of $234 million, net of fees. As of December 31, 2012, PG&E Corporation had the ability to issue an additional $64 million of its common stock under the November 2011 Equity Distribution Agreement. In March 2012, PG&E Corporation sold 5,900,000 shares of its common stock in an underwritten public offering for cash proceeds of $254 million, net of fees and commissions.

Utility

As of December 31, 2012, PG&E Corporation held all of the Utility's outstanding common stock.

Dividends

The Board of Directors of PG&E Corporation and the Utility declare dividends quarterly. Under the Utility's Articles of Incorporation, the Utility cannot pay common stock dividends unless all cumulative preferred dividends on the Utility's preferred stock have been paid. In February, June, September, and December, 2012, the Board of Directors of PG&E Corporation declared a quarterly dividend of $0.455 per share.

PG&E Corporation and the Utility each have revolving credit facilities that require the respective company to maintain a ratio of consolidated total debt to consolidated capitalization of at most 65%. Based on the calculation of this ratio for PG&E Corporation, no amount of PG&E Corporation's reinvested earnings was restricted at December 31, 2012. Based on the calculation of this ratio for the Utility, $1.1 billion of the Utility's reinvested earnings was restricted at December 31, 2012. In addition, the CPUC requires the Utility to maintain a capital structure composed of at least 52% equity on average. At December 31, 2012, the Utility was required to maintain reinvested earnings of $6.3 billion as equity to meet this requirement.

In addition, to comply with the revolving credit facility's 65% ratio requirement and the CPUC's requirement to maintain a 52% equity component, $7.0 billion and $12.2 billion of the Utility's net assets, respectively, were restricted at December 31, 2012 and could not be transferred to PG&E Corporation in the form of cash dividends. As a holding company, PG&E Corporation depends on cash distributions from the Utility to meet its debt service and other financial obligations and to pay dividends on its common stock.

NOTE 6: COMMON STOCK AND SHARE-BASED COMPENSATION (Continued)

Long-Term Incentive Plan

The PG&E Corporation 2006 Long-Term Incentive Plan ("2006 LTIP") permits the award of various forms of incentive awards, including stock options, stock appreciation rights, restricted stock awards, restricted stock units ("RSUs"), performance shares, deferred compensation awards, and other share-based awards, to eligible employees of PG&E Corporation and its subsidiaries. Non-employee directors of PG&E Corporation are also eligible to receive share-based awards under the formula grant provisions of the 2006 LTIP. A maximum of 12 million shares of PG&E Corporation common stock (subject to adjustment for changes in capital structure, stock dividends, or other similar events) has been reserved for issuance under the 2006 LTIP, of which 4,548,119 shares were available for award at December 31, 2012.

The following table provides a summary of total compensation expense for PG&E Corporation for share-based incentive awards for 2012, 2011, and 2010:

(in millions)	2012	2011	2010
Restricted stock units	$ 31	$ 22	$ 9
Other share-based compensation	—	1	14
Performance shares:			
Equity awards	26	16	11
Liability awards	—	(13)	22
Total compensation expense (pre-tax)	**$ 57**	**$ 26**	**$ 56**
Total compensation expense (after-tax)	**$ 34**	**$ 16**	**$ 33**

There were no significant share-based compensation costs capitalized during 2012, 2011, and 2010. There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

Restricted Stock Units

Each RSU represents one hypothetical share of PG&E Corporation common stock. RSUs generally vest in 20% increments on the first business day of March in year one, two, and three, with the remaining 40% vesting on the first business day of March in year four. Vested RSUs are settled in shares of PG&E Corporation common stock. Additionally, upon settlement, RSU recipients receive payment for the amount of dividend equivalents associated with the vested RSUs that have accrued since the date of grant. RSU expense is recognized ratably over the requisite service period based on the fair values determined, except for the expense attributable to awards granted to retirement-eligible participants, which is recognized on the date of grant.

The weighted average grant-date fair value per RSUs granted during 2012, 2011, and 2010 was $42.17, $45.10, and $42.97, respectively. The total fair value of RSUs that vested during 2012, 2011, and 2010 was $18 million, $11 million, and $5 million, respectively. The tax benefit from RSUs that vested during 2012, 2011, and 2010 was not material. As of December 31, 2012, $44 million of total unrecognized compensation costs related to nonvested RSUs was expected to be recognized over the remaining weighted average period of 2.19 years.

The following table summarizes RSU activity for 2012:

	Number of Restricted Stock Units	Weighted Average Grant-Date Fair Value
Nonvested at January 1	1,626,048	$ 42.57
Granted	923,001	$ 42.17
Vested	(424,034)	$ 41.88
Forfeited	(55,724)	$ 42.64
Nonvested at December 31	**2,069,291**	$ 42.52

NOTE 6: COMMON STOCK AND SHARE-BASED COMPENSATION (Continued)

Performance Shares

In 2012, PG&E Corporation granted 834,420 contingent performance shares to eligible employees. Performance shares vest after three years of service. Performance shares granted in 2012, 2011, and 2010 are settled in shares of PG&E Corporation common stock and are classified as share-based equity awards. Performance-based awards granted prior to 2010 are settled in cash and classified as a liability. The amount of common stock (or cash with respect to grants before 2010) that recipients are entitled to receive, if any, will be determined based on PG&E Corporation's annual total shareholder return relative to the performance of a specified group of peer companies for the applicable three-year performance period. Total compensation expense for performance shares is based on the grant-date fair value, which is determined using a Monte Carlo simulation valuation model. Performance share expense is recognized ratably over the requisite service period based on the fair values determined, except for the expense attributable to awards granted to retirement-eligible participants, which is recognized on the date of grant. Dividend equivalents on performance shares, if any, will be paid in cash upon the vesting date based on the amount of common stock to which the recipients are entitled.

The weighted average grant-date fair value for performance shares granted during 2012, 2011, and 2010 was $41.93, $33.91, and $35.60 respectively. There was no tax benefit associated with performance shares that vested during 2012, 2011, and 2010, as awards that settle in cash have no tax impact, and awards that settle in shares do not generate a tax benefit until vested. The performance shares awarded in March 2010 will vest in March 2013. As of December 31, 2012, $29 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted average period of 1.28 years.

The following table summarizes performance shares classified as equity awards activity for 2012:

	Number of Performance Shares	Weighted Average Grant-Date Fair Value
Nonvested at January 1	1,325,406	$ 34.64
Granted	834,420	$ 41.93
Vested	(425)	$ 34.86
Forfeited[1]	(661,928)	$ 35.71
Nonvested at December 31	**1,497,473**	$ 38.15

[1] Includes performance shares that expired with zero value as performance targets were not met.

NOTE 7: PREFERRED STOCK

PG&E Corporation

PG&E Corporation has authorized 80 million shares of no par value preferred stock and 5 million shares of $100 par value preferred stock, which may be issued as redeemable or nonredeemable preferred stock. PG&E Corporation does not have any preferred stock outstanding.

Utility

The Utility has authorized 75 million shares of $25 par value preferred stock and 10 million shares of $100 par value preferred stock. The Utility specifies that 5,784,825 shares of the $25 par value preferred stock authorized are designated as nonredeemable preferred stock without mandatory redemption provisions. All remaining shares of preferred stock may be issued as redeemable or nonredeemable preferred stock.

NOTE 7: PREFERRED STOCK (Continued)

The following table summarizes the Utility's outstanding preferred stock, none of which had mandatory redemption provisions at December 31, 2012 and 2011:

(in millions, except share amounts, redemption price, and par value)	Shares Outstanding	Redemption Price	Balance
Nonredeemable $25 par value preferred stock			
5.00% Series	400,000	N/A	$ 10
5.50% Series	1,173,163	N/A	30
6.00% Series	4,211,662	N/A	105
Total nonredeemable preferred stock	**5,784,825**		**$ 145**
Redeemable $25 par value preferred stock			
4.36% Series	418,291	$ 25.75	$ 11
4.50% Series	611,142	26.00	15
4.80% Series	793,031	27.25	20
5.00% Series	1,778,172	26.75	44
5.00% Series A	934,322	26.75	23
Total redeemable preferred stock	**4,534,958**		**$ 113**
Preferred stock			**$ 258**

At December 31, 2012, annual dividends on the Utility's nonredeemable preferred stock ranged from $1.25 to $1.50 per share. The Utility's redeemable preferred stock is subject to redemption at the Utility's option, in whole or in part, if the Utility pays the specified redemption price plus accumulated and unpaid dividends through the redemption date. At December 31, 2012, annual dividends on redeemable preferred stock ranged from $1.09 to $1.25 per share.

Dividends on all Utility preferred stock are cumulative. All shares of preferred stock have voting rights and an equal preference in dividend and liquidation rights. Upon liquidation or dissolution of the Utility, holders of preferred stock would be entitled to the par value of such shares plus all accumulated and unpaid dividends, as specified for the class and series. During each of 2012, 2011, and 2010 the Utility paid $14 million of dividends on preferred stock.

NOTE 8: EARNINGS PER SHARE

PG&E Corporation's basic earnings per common share ("EPS") is calculated by dividing the income available for common shareholders by the weighted average number of common shares outstanding. PG&E Corporation applies the treasury stock method of reflecting the dilutive effect of outstanding share-based compensation in the calculation of diluted EPS. The following is a reconciliation of PG&E Corporation's income available for common shareholders and weighted average common shares outstanding for calculating diluted EPS for 2012 and 2011.

(in millions, except per share amounts)	Year Ended December 31, 2012	Year Ended December 31, 2011
Income available for common shareholders	$ 816	$ 844
Weighted average common shares outstanding, basic	424	401
Add incremental shares from assumed conversions:		
Employee share-based compensation	1	1
Weighted average common share outstanding, diluted	425	402
Total earnings per common share, diluted	**$ 1.92**	**$ 2.10**

For 2010, PG&E Corporation calculated EPS using the "two-class" method because PG&E Corporation's convertible subordinated notes that were outstanding prior to June 29, 2010 were considered to be participating

NOTE 8: EARNINGS PER SHARE (Continued)

securities. In applying the two-class method, undistributed earnings were allocated to both common shares and participating securities. In calculating diluted EPS for 2010, PG&E Corporation applied the "if-converted" method to reflect the dilutive effect of the convertible subordinated notes to the extent that the impact was dilutive when compared to basic EPS. The following is a reconciliation of PG&E Corporation's income available for common shareholders and weighted average common shares outstanding for calculating basic and diluted EPS for 2010:

(in millions, except per share amounts)	Year Ended December 31, 2010 Basic	Year Ended December 31, 2010 Diluted
Income available for common shareholders	$ 1,099	$ 1,099
Less: distributed earnings to common shareholders	706	—
Undistributed earnings	**$ 393**	**$ 1,099**
Allocation of earnings to common shareholders		
Distributed earnings to common shareholders	$ 706	$ —
Undistributed earnings allocated to common shareholders	385	1,099
Add: Interest expense on convertible subordinated notes, net of tax	—	8
Total common shareholders earnings and assumed conversion	**$ 1,091**	**$ 1,107**
Weighted average common shares outstanding	382	382
Add incremental shares from assumed conversions:		
Convertible subordinated notes	8	8
Employee share-based compensation	—	2
Weighted average common shares outstanding and participating securities	**390**	**392**
Net earnings per common share, basic		
Distributed earnings, basic[1]	$ 1.85	$ —
Undistributed earnings	1.01	2.82
Total	**$ 2.86**	**$ 2.82**

[1] Distributed earnings, basic may differ from actual per share amounts paid as dividends, as the EPS computation under GAAP requires the use of the weighted average, rather than the actual, number of shares outstanding.

For each of the periods presented above, the calculation of outstanding common shares on a diluted basis excluded an insignificant amount of options and securities that were antidilutive.

NOTE 9: INCOME TAXES

The significant components of income tax provision (benefit) by taxing jurisdiction were as follows:

	PG&E Corporation			Utility		
	Year Ended December 31,					
(in millions)	2012	2011	2010	2012	2011	2010
Current:						
Federal	$ (74)	$ (77)	$ (12)	$ (52)	$ (83)	$ (54)
State	33	152	130	41	161	134
Deferred:						
Federal	374	504	525	404	534	589
State	(92)	(135)	(91)	(91)	(128)	(90)
Tax credits	(4)	(4)	(5)	(4)	(4)	(5)
Income tax provision	**$ 237**	**$ 440**	**$ 547**	**$ 298**	**$ 480**	**$ 574**

NOTE 9: INCOME TAXES (Continued)

The following table describes net deferred income tax liabilities:

	PG&E Corporation		Utility	
	Year Ended December 31,			
(in millions)	2012	2011	2012	2011
Deferred income tax assets:				
Customer advances for construction	$ 101	$ 108	$ 101	$ 108
Reserve for damages	175	243	175	243
Environmental reserve	97	157	97	157
Compensation	229	310	179	258
Net operating loss carry forward	938	728	736	567
Other	264	217	255	180
Total deferred income tax assets	**$ 1,804**	**$ 1,763**	**$ 1,543**	**$ 1,513**
Deferred income tax liabilities:				
Regulatory balancing accounts	$ 256	$ 643	$ 256	$ 643
Property related basis differences	7,449	6,544	7,447	6,536
Income tax regulatory asset	663	588	663	588
Other	173	192	99	105
Total deferred income tax liabilities	**$ 8,541**	**$ 7,967**	**$ 8,465**	**$ 7,872**
Total net deferred income tax liabilities	**$ 6,737**	**$ 6,204**	**$ 6,922**	**$ 6,359**
Classification of net deferred income tax liabilities:				
Included in current liabilities (assets)	$ (11)	$ 196	$ (17)	$ 199
Included in noncurrent liabilities	6,748	6,008	6,939	6,160
Total net deferred income tax liabilities	**$ 6,737**	**$ 6,204**	**$ 6,922**	**$ 6,359**

The following table reconciles income tax expense at the federal statutory rate to the income tax provision:

	PG&E Corporation			Utility		
	Year Ended December 31,					
	2012	2011	2010	2012	2011	2010
Federal statutory income tax rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) in income tax rate resulting from:						
State income tax (net of federal benefit)	(3.9)	1.1	0.7	(3.0)	1.6	1.0
Effect of regulatory treatment of fixed asset differences	(4.1)	(4.4)	(3.1)	(3.9)	(4.2)	(3.0)
Tax credits	(0.6)	(0.5)	(0.4)	(0.6)	(0.5)	(0.4)
Benefit of loss carryback	(0.7)	(1.9)	—	(0.4)	(2.1)	—
Non deductible penalties	0.6	6.5	0.2	0.5	6.3	0.2
Other, net	(3.8)	(1.5)	0.8	(0.8)	0.1	1.1
Effective tax rate	**22.5%**	**34.3%**	**33.2%**	**26.8%**	**36.2%**	**33.9%**

NOTE 9: INCOME TAXES (Continued)

Unrecognized tax benefits

The following table reconciles the changes in unrecognized tax benefits:

	PG&E Corporation			Utility		
(in millions)	**2012**	**2011**	**2010**	**2012**	**2011**	**2010**
Balance at beginning of year	$ 506	$ 714	$ 673	$ 503	$ 712	$ 652
Additions for tax position taken during a prior year	32	2	27	26	2	27
Reductions for tax position taken during a prior year	(13)	(198)	(20)	(10)	(196)	—
Additions for tax position taken during the current year	67	3	89	67	—	87
Settlements	(11)	(15)	(55)	(11)	(15)	(54)
Balance at end of year	**$ 581**	**$ 506**	**$ 714**	**$ 575**	**$ 503**	**$ 712**

The component of unrecognized tax benefits that, if recognized, would affect the effective tax rate at December 31, 2012 for PG&E Corporation and the Utility was $18 million, with the remaining balance representing the potential deferral of taxes to later years.

PG&E Corporation and the Utility recognize accrued interest related to unrecognized tax benefits as income tax expense in the Consolidated Statements of Income. Interest income and interest expense for the years ended December 31, 2012, December 31, 2011, and December 31, 2010 were immaterial.

As of December 31, 2012 and December 31, 2011, PG&E Corporation and the Utility had receivables for accrued interest income. The amounts of these receivables were immaterial.

The Internal Revenue Service ("IRS") is working with the utility industry to finalize guidance on what is a repair deduction for tax purposes for the natural gas transmission, natural gas distribution, and electric generation businesses. PG&E Corporation and the Utility expect the IRS to release this guidance in the first half of 2013. PG&E Corporation and the Utility expect the unrecognized tax benefits may change significantly within the next 12 months.

The IRS is auditing a 2008 accounting method change of the Utility to accelerate the amount of deductible repairs. The audit is expected to be completed in 2013. The resolution of the audit could result in a significant change in unrecognized tax benefit. However, PG&E Corporation and the Utility cannot estimate the change of unrecognized tax benefits related to the items discussed above.

Tax settlements and years that remain subject to examination

In 2008, PG&E Corporation began participating in the Compliance Assurance Process ("CAP"), a real-time IRS audit intended to expedite resolution of tax matters. The CAP audit culminates with a letter from the IRS indicating its acceptance of the return. The IRS partially accepted the 2008 return, withholding two matters for further review. In December 2010, the IRS accepted the 2009 tax return without change. In September 2011, the IRS partially accepted the 2010 return, withholding two matters for further review. In September 2012, the IRS partially accepted the 2011 return, withholding several matters for future review.

The most significant of the matters withheld for further review in each of these years relates to a tax accounting method change of the Utility related to repairs. The IRS has not completed its review of these claims.

Loss carry forwards

As of December 31, 2012, PG&E Corporation had approximately $2.1 billion of federal net operating loss carry forwards and $12 million of tax credit carry forwards, which will expire between 2029 and 2032. In addition, PG&E Corporation had approximately $128 million of loss carry forwards related to charitable contributions, which will expire between 2013 and 2017. PG&E Corporation believes it is more likely than not the tax benefits associated with

NOTE 9: INCOME TAXES (Continued)

the federal operating loss, charitable contributions, and tax credits can be realized within the carry forward periods, therefore no valuation allowance was recognized as of December 31, 2012. As of December 31, 2012, PG&E Corporation had approximately $19 million of federal net operating loss carry forwards related to the tax benefit on employee stock plans that would be recorded in additional paid-in capital when used.

NOTE 10: DERIVATIVES

Use of Derivative Instruments

The Utility uses both derivative and non-derivative contracts in managing its customers' exposure to commodity-related price risk, including:

- forward contracts that commit the Utility to purchase a commodity in the future;
- swap agreements and futures contracts that require payments to or from counterparties based upon the difference between two prices for a predetermined contractual quantity; and
- option contracts that provide the Utility with the right to buy a commodity at a predetermined price and option contracts that require payments from counterparties if market prices exceed a predetermined price.

These instruments are not held for speculative purposes and are subject to certain regulatory requirements. Customer rates are designed to recover the Utility's reasonable costs of providing services, including the costs related to price risk management activities.

Price risk management activities that meet the definition of derivatives are recorded at fair value on the Consolidated Balance Sheets. As long as the current ratemaking mechanism discussed above remains in place and the Utility's price risk management activities are carried out in accordance with CPUC directives, the Utility expects to recover fully, in rates, all costs related to derivatives. Therefore, all unrealized gains and losses associated with the change in fair value of these derivatives are deferred and recorded within the Utility's regulatory assets and liabilities on the Consolidated Balance Sheets. (See Note 3 above.) Net realized gains or losses on commodity derivatives are recorded in the cost of electricity or the cost of natural gas with corresponding increases or decreases to regulatory balancing accounts for recovery from or refund to customers.

The Utility elects the normal purchase and sale exception for eligible derivatives. Derivatives that require physical delivery in quantities that are expected to be used by the Utility over a reasonable period in the normal course of business, and do not contain pricing provisions unrelated to the commodity delivered are eligible for the normal purchase and sale exception. The fair value of derivatives that are eligible for the normal purchase and sales exception are not reflected in the Consolidated Balance Sheets.

Electricity Procurement

The Utility enters into third-party power purchase agreements for electricity to meet customer needs. The Utility's third-party power purchase agreements are generally accounted for as leases, but certain third-party power purchase agreements are considered derivatives. The Utility elects the normal purchase and sale exception for eligible derivatives.

A portion of the Utility's third-party power purchase agreements contain market-based pricing terms. In order to reduce volatility in customer rates, the Utility may enter into financial swap and/or financial option contracts to effectively fix and/or cap the price of future purchases and reduce cash flow variability associated with fluctuating electricity prices. These financial contracts are considered derivatives.

Electric Transmission Congestion Revenue Rights

The California electric transmission grid, controlled by the California Independent System Operator ("CAISO"), is subject to transmission constraints when there is insufficient transmission capacity to supply the market. The CAISO imposes congestion charges on market participants to manage transmission congestion. The revenue generated from congestion charges is allocated to holders of congestion revenue rights ("CRRs"). CRRs allow market participants to hedge the financial risk of CAISO-imposed congestion charges in the day-ahead market. The

NOTE 10: DERIVATIVES (Continued)

CAISO releases CRRs through an annual and monthly process, each of which includes an allocation phase (in which load-serving entities, such as the Utility, are allocated CRRs at no cost based on the customer demand or "load" they serve) and an auction phase (in which CRRs are priced at market and available to all market participants). The Utility participates in the allocation and auction phases of the annual and monthly CRR processes. CRRs are considered derivatives.

Natural Gas Procurement (Electric Fuels Portfolio)

The Utility's electric procurement portfolio is exposed to natural gas price risk primarily through physical natural gas commodity purchases to fuel natural gas generating facilities, and electricity procurement contracts indexed to natural gas prices. To reduce the volatility in customer rates, the Utility may enter into financial swap contracts or financial option contracts, or both. The Utility also enters into fixed-price forward contracts for natural gas to reduce future cash flow variability from fluctuating natural gas prices. These instruments are considered derivatives.

Natural Gas Procurement (Core Gas Supply Portfolio)

The Utility enters into physical natural gas commodity contracts to fulfill the needs of its residential and smaller commercial customers known as "core" customers. The Utility does not procure natural gas for industrial and large commercial, or "non-core," customers. Changes in temperature cause natural gas demand to vary daily, monthly, and seasonally. Consequently, varying volumes of natural gas may be purchased or sold in the multi-month, monthly, and to a lesser extent, daily spot market to balance such seasonal supply and demand. The Utility purchases financial instruments, such as swaps and options, as part of its core winter hedging program in order to manage customer exposure to high natural gas prices during peak winter months. These financial instruments are considered derivatives.

Volume of Derivative Activity

At December 31, 2012, the volumes of PG&E Corporation's and the Utility's outstanding derivatives were as follows:

		Contract Volume[1]			
Underlying Product	**Instruments**	**Less Than 1 Year**	**1 Year or Greater but Less Than 3 Years**	**3 Years or Greater but Less Than 5 Years**	**5 Years or Greater[2]**
Natural Gas[3] (MMBtus[4])	Forwards and Swaps	329,466,510	98,628,398	5,490,000	—
	Options	221,587,431	216,279,767	10,050,000	—
Electricity (Megawatt-hours)	Forwards and Swaps	2,537,023	3,541,046	2,009,505	2,538,718
	Options	—	239,015	239,233	119,508
	Congestion Revenue Rights	74,198,690	74,187,803	74,240,147	25,699,804

(1) Amounts shown reflect the total gross derivative volumes by commodity type that are expected to settle in each period.
(2) Derivatives in this category expire between 2018 and 2023.
(3) Amounts shown are for the combined positions of the electric fuels and core gas portfolios.
(4) Million British Thermal Units.

NOTE 10: DERIVATIVES (Continued)

At December 31, 2011, the volumes of PG&E Corporation's and the Utility's outstanding derivatives were as follows:

		Contract Volume[1]			
Underlying Product	**Instruments**	**Less Than 1 Year**	**1 Year or Greater but Less Than 3 Years**	**3 Years or Greater but Less Than 5 Years**	**5 Years or Greater[2]**
Natural Gas[3] (MMBtus[4])	Forwards and Swaps	500,375,394	212,088,902	6,080,000	—
	Options	257,766,990	336,543,013	—	—
Electricity (Megawatt-hours)	Forwards and Swaps	4,718,568	5,206,512	2,142,024	3,754,872
	Options	1,248,000	132,048	264,348	264,096
	Congestion Revenue Rights	84,247,502	72,882,246	72,949,250	61,673,535

(1) Amounts shown reflect the total gross derivative volumes by commodity type that are expected to settle in each period.
(2) Derivatives in this category expire between 2017 and 2022.
(3) Amounts shown are for the combined positions of the electric fuels and core gas portfolios.
(4) Million British Thermal Units.

Presentation of Derivative Instruments in the Financial Statements

In PG&E Corporation's and the Utility's Consolidated Balance Sheets, derivatives are presented on a net basis by counterparty where the right and the intention to offset exists under a master netting agreement. The net balances include outstanding cash collateral associated with derivative positions.

At December 31, 2012, PG&E Corporation's and the Utility's outstanding derivative balances were as follows:

	Commodity Risk			
(in millions)	**Gross Balance**	**Netting**	**Cash Collateral**	**Total Balance**
Current assets—other	$ 48	$ (25)	$ 36	$ 59
Other noncurrent assets—other	99	(11)	—	88
Current liabilities—other	(255)	25	115	(115)
Noncurrent liabilities—other	(221)	11	14	(196)
Total commodity risk	**$ (329)**	**$ —**	**$ 165**	**$ (164)**

At December 31, 2011, PG&E Corporation's and the Utility's outstanding derivative balances were as follows:

	Commodity Risk			
(in millions)	**Gross Balance**	**Netting**	**Cash Collateral**	**Total Balance**
Current assets—other	$ 54	$ (39)	$ 103	$ 118
Other noncurrent assets—other	113	(59)	—	54
Current liabilities—other	(489)	39	274	(176)
Noncurrent liabilities—other	(398)	59	101	(238)
Total commodity risk	**$ (720)**	**$ —**	**$ 478**	**$ (242)**

NOTE 10: DERIVATIVES (Continued)

Gains and losses recorded on PG&E Corporation's and the Utility's derivatives were as follows:

	Commodity Risk		
	For the year ended December 31,		
(in millions)	**2012**	**2011**	**2010**
Unrealized gain/(loss)—regulatory assets and liabilities[1]	$ 391	$ 21	$ (260)
Realized loss—cost of electricity[2]	(486)	(558)	(573)
Realized loss—cost of natural gas[2]	(38)	(106)	(79)
Total commodity risk	**$ (133)**	**$ (643)**	**$ (912)**

(1) Unrealized gains and losses on commodity risk-related derivative instruments are recorded to regulatory assets or liabilities, rather than being recorded to the Consolidated Statements of Income. These amounts exclude the impact of cash collateral postings.

(2) These amounts are fully passed through to customers in rates. Accordingly, net income was not impacted by realized amounts on these instruments.

Cash inflows and outflows associated with derivatives are included in operating cash flows on PG&E Corporation's and the Utility's Consolidated Statements of Cash Flows.

The majority of the Utility's derivatives contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies. At December 31, 2012, the Utility's credit rating was investment grade. If the Utility's credit rating were to fall below investment grade, the Utility would be required to post additional cash immediately to fully collateralize some of its net liability derivative positions.

The additional cash collateral that the Utility would be required to post if the credit risk-related contingency features were triggered was as follows:

	Balance at December 31,	
(in millions)	**2012**	**2011**
Derivatives in a liability position with credit risk-related contingencies that are not fully collateralized	$ (266)	$ (611)
Related derivatives in an asset position	59	86
Collateral posting in the normal course of business related to these derivatives	103	250
Net position of derivative contracts/additional collateral posting requirements[1]	**$ (104)**	**$ (275)**

(1) This calculation excludes the impact of closed but unpaid positions, as their settlement is not impacted by any of the Utility's credit risk-related contingencies.

NOTE 11: FAIR VALUE MEASUREMENTS

PG&E Corporation and the Utility measure their cash equivalents, trust assets, and price risk management instruments at fair value. Fair value is an exit price, representing the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. As such, fair value is a market-based measurement that should be determined based on assumptions that market participants would use in pricing an asset or a liability. A three-tier fair value hierarchy is established as a basis for considering such assumptions and for inputs used in the valuation methodologies in measuring fair value:

- **Level 1**—Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.
- **Level 2**—Other inputs that are directly or indirectly observable in the marketplace.
- **Level 3**—Unobservable inputs which are supported by little or no market activities.

The fair value hierarchy requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

NOTE 11: FAIR VALUE MEASUREMENTS (Continued)

Assets and liabilities measured at fair value on a recurring basis for PG&E Corporation and the Utility are summarized below (assets held in rabbi trusts are held by PG&E Corporation and not the Utility):

	Fair Value Measurements At December 31, 2012				
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Netting[1]**	**Total**
Assets:					
Money market investments	$ 209	$ —	$ —	$ —	**$ 209**
Nuclear decommissioning trusts					
Money market investments	21	—	—	—	**21**
U.S. equity securities	940	9	—	—	**949**
Non-U.S. equity securities	379	—	—	—	**379**
U.S. government and agency securities	681	139	—	—	**820**
Municipal securities	—	59	—	—	**59**
Other fixed-income securities	—	173	—	—	**173**
Total nuclear decommissioning trusts[2]	**2,021**	**380**	**—**	**—**	**2,401**
Price risk management instruments (Note 10)					
Electricity	1	60	80	6	**147**
Gas	—	5	1	(6)	**—**
Total price risk management instruments	**1**	**65**	**81**	**—**	**147**
Rabbi trusts					
Fixed-income securities	—	30	—	—	**30**
Life insurance contracts	—	72	—	—	**72**
Total rabbi trusts	**—**	**102**	**—**	**—**	**102**
Long-term disability trust					
Money market investments	10	—	—	—	**10**
U.S. equity securities	—	14	—	—	**14**
Non-U.S. equity securities	—	11	—	—	**11**
Fixed-income securities	—	136	—	—	**136**
Total long-term disability trust	10	161	—	—	**171**
Total assets	**$ 2,241**	**$ 708**	**$ 81**	**$ —**	**$ 3,030**
Liabilities:					
Price risk management instruments (Note 10)					
Electricity	$ 155	$ 144	$ 160	$ (156)	**$ 303**
Gas	8	9	—	(9)	**8**
Total liabilities	**$ 163**	**$ 153**	**$ 160**	**$ (165)**	**$ 311**

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
(2) Excludes $240 million at December 31, 2012 primarily related to deferred taxes on appreciation of investment value.

NOTE 11: FAIR VALUE MEASUREMENTS (Continued)

	Fair Value Measurements At December 31, 2011				
(in millions)	Level 1	Level 2	Level 3	Netting[1]	Total
Assets:					
Money market investments	$ 206	$ —	$ —	$ —	$ **206**
Nuclear decommissioning trusts					
Money market investments	24	—	—	—	**24**
U.S. equity securities	841	8	—	—	**849**
Non-U.S. equity securities	323	—	—	—	**323**
U.S. government and agency securities	720	156	—	—	**876**
Municipal securities	—	58	—	—	**58**
Other fixed-income securities	—	99	—	—	**99**
Total nuclear decommissioning trusts[2]	**1,908**	**321**	**—**	**—**	**2,229**
Price risk management instruments (Note 10)					
Electricity	—	92	69	8	**169**
Gas	—	6	—	(3)	**3**
Total price risk management instruments	**—**	**98**	**69**	**5**	**172**
Rabbi trusts					
Fixed-income securities	—	25	—	—	**25**
Life insurance contracts	—	67	—	—	**67**
Total rabbi trusts	**—**	**92**	**—**	**—**	**92**
Long-term disability trust					
Money market investments	13	—	—	—	**13**
U.S. equity securities	—	15	—	—	**15**
Non-U.S. equity securities	—	9	—	—	**9**
Fixed-income securities	—	145	—	—	**145**
Total long-term disability trust	**13**	**169**	**—**	**—**	**182**
Total assets	**$ 2,127**	**$ 680**	**$ 69**	**$ 5**	**$ 2,881**
Liabilities:					
Price risk management instruments (Note 10)					
Electricity	$ 411	$ 289	$ 143	$ (441)	$ **402**
Gas	31	13	—	(32)	**12**
Total liabilities	**$ 442**	**$ 302**	**$ 143**	**$ (473)**	**$ 414**

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
(2) Excludes $188 million at December 31, 2011 primarily related to deferred taxes on appreciation of investment value.

Valuation Techniques

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the table above:

Money Market Investments

PG&E Corporation and the Utility invest in money market funds that seek to maintain a stable net asset value. These funds invest in high quality, short-term, diversified money market instruments, such as U.S. Treasury bills, U.S. agency securities, certificates of deposit, and commercial paper with a maximum weighted average maturity of

NOTE 11: FAIR VALUE MEASUREMENTS (Continued)

60 days or less. PG&E Corporation's and the Utility's investments in these money market funds are valued using unadjusted prices for identical assets in an active market and are thus classified as Level 1. Money market funds are recorded as cash and cash equivalents in PG&E Corporation's and the Utility's Consolidated Balance Sheets.

Trust Assets

The assets held by the nuclear decommissioning trusts, the rabbi trusts related to the non-qualified deferred compensation plans, and the long-term disability trust are composed primarily of equity securities, debt securities, and life insurance policies. In general, investments held in the trusts are exposed to various risks, such as interest rate, credit, and market volatility risks.

Equity securities primarily include investments in common stock, which are valued based on unadjusted prices for identical securities in active markets and are classified as Level 1. Equity securities also include commingled funds composed of equity securities traded publicly on exchanges across multiple industry sectors in the U.S. and other regions of the world, which are classified as Level 2. Price quotes for the assets held by these funds are readily observable and available.

Debt securities are primarily composed of U.S. government and agency securities, municipal securities, and other fixed-income securities, including corporate debt securities. U.S. government and agency securities primarily consist of U.S. Treasury securities that are classified as Level 1 because the fair value is determined by observable market prices in active markets. A market approach is generally used to estimate the fair value of debt securities classified as Level 2. Under a market approach, fair values are determined based on evaluated pricing data, such as broker quotes, for similar securities adjusted for observable differences. Significant inputs used in the valuation model generally include benchmark yield curves and issuer spreads. The external credit ratings, coupon rate, and maturity of each security are considered in the valuation model, as applicable.

Price Risk Management Instruments

Price risk management instruments include physical and financial derivative contracts, such as power purchase agreements, forwards, swaps, options, and CRRs that are traded either on an exchange or over-the-counter. (See Note 10 above.)

Power purchase agreements, forwards, and swaps are valued using a discounted cash flow model. Exchange-traded forwards and swaps that are valued using observable market forward prices for the underlying commodity are classified as Level 1. Over-the-counter forwards and swaps that are identical to exchange-traded forwards and swaps or are valued using forward prices from broker quotes that are corroborated with market data are classified as Level 2. Long-dated power purchase agreements that are valued using significant unobservable data are classified as Level 3. These Level 3 contracts are valued using either estimated basis adjustments from liquid trading points or techniques, including extrapolation from observable prices, when a contract term extends beyond a period for which market data is available.

Exchange-traded options are valued using observable market data and market-corroborated data and are classified as Level 2. Over-the-counter options are classified as Level 3 and are valued using a standard option pricing model, which includes forward prices for the underlying commodity, time value at a risk-free rate, and volatility. For periods where market data is not available, the Utility extrapolates observable data using internal models.

The Utility holds CRRs to hedge the financial risk of CAISO-imposed congestion charges in the day-ahead market. CRRs are valued based on prices observed in the CAISO auction, which are discounted at the risk-free rate. Limited market data is available in the CAISO auction and between auction dates; therefore, the Utility uses models to forecast CRR prices for those periods not covered in the auctions. CRRs are classified as Level 3.

NOTE 11: FAIR VALUE MEASUREMENTS (Continued)

Transfers between Levels

PG&E Corporation and the Utility recognize any transfers between levels in the fair value hierarchy as of the end of the reporting period. For the year ended December 31, 2012, there were no significant transfer between levels.

At December 31, 2011, the valuation of price risk management over-the-counter forwards and swaps and exchange-traded options incorporated market observable and market corroborated inputs, where certain previously-considered unobservable inputs became observable. Therefore, the Utility transferred these instruments out of Level 3 and into Level 2. There were no significant transfers between Levels 1 and 2 in the year ended December 31, 2011.

Level 3 Measurements and Sensitivity Analysis

The Utility's Market and Credit Risk Management department is responsible for determining the fair value of the Utility's price risk management derivatives. Market and Credit Risk Management reports to the Chief Risk Officer of the Utility. Market and Credit Risk Management utilizes models to derive pricing inputs for the valuation of the Utility's Level 3 instruments. These models use pricing inputs from brokers and historical data. The Market and Credit Risk Management department and the Controller's organization collaborate to determine the appropriate fair value methodologies and classification for each derivative. Inputs used and fair value of Level 3 instruments are reviewed period-over-period and compared with market conditions to determine reasonableness. Valuation models and techniques are reviewed periodically.

CRRs and power purchase agreements are valued using historical prices or significant unobservable inputs derived from internally developed models. Historical prices include CRR auction prices. Unobservable inputs include forward electricity prices. Significant increases or decreases in any of those inputs would result in a significantly higher or lower fair value, respectively. All reasonable costs related to Level 3 instruments are expected to be recoverable through customer rates; therefore, there is no impact to net income resulting from changes in the fair value of these instruments. (See Note 10 above.)

(in millions)	Fair Value at December 31, 2012				
Fair Value Measurement	Assets	Liabilities	Valuation Technique	Unobservable Input	Range[1]
Congestion revenue rights	$ 80	$ 16	Market approach	CRR auction prices	$ (9.04) - 55.15
Power purchase agreements	$ —	$ 145	Discounted cash flow	Forward prices	$ 8.59 - 62.90

[1] Represents price per megawatt-hour

NOTE 11: FAIR VALUE MEASUREMENTS (Continued)

Level 3 Reconciliation

The following table presents the reconciliation for Level 3 price risk management instruments for the years ended December 31, 2012 and 2011, respectively:

	Price Risk Management Instruments	
(in millions)	2012	2011
Liability balance as of January 1	$ (74)	$ (399)
Realized and unrealized gains (losses):		
Included in regulatory assets and liabilities or balancing accounts[1]	(5)	122
Transfers out of Level 3	—	203
Liability balance as of December 31	**$ (79)**	**$ (74)**

(1) Price risk management activities are recoverable through customer rates, therefore, balancing account revenue is recorded for amounts settled and purchased and there is no impact to net income. Unrealized gains and losses are deferred in regulatory liabilities and assets.

Financial Instruments

PG&E Corporation and the Utility use the following methods and assumptions in estimating fair value for financial instruments:

- The fair values of cash, restricted cash, net accounts receivable, short-term borrowings, accounts payable, customer deposits, and the Utility's variable rate pollution control bond loan agreements approximate their carrying values at December 31, 2012 and 2011, as they are short-term in nature or have interest rates that reset daily.
- The fair values of the Utility's fixed-rate senior notes and fixed-rate pollution control bond loan agreements and PG&E Corporation's fixed-rate senior notes were based on quoted market prices at December 31, 2012 and 2011. The fair value of the ERBs issued by PERF was also based on quoted market prices at December 31, 2011.

The carrying amount and fair value of PG&E Corporation's and the Utility's debt instruments were as follows (the table below excludes financial instruments with carrying values that approximate their fair values):

	At December 31,			
	2012		2011	
(in millions)	Carrying Amount	Level 2 Fair Value	Carrying Amount	Level 2 Fair Value
Debt (Note 4)				
PG&E Corporation	$ 349	$ 371	$ 349	$ 380
Utility	11,645	13,946	10,545	12,543
Energy recovery bonds (Note 5)	—	—	423	433

NOTE 11: FAIR VALUE MEASUREMENTS (Continued)

Nuclear Decommissioning Trust Investments

The following table provides a summary of available-for-sale investments held in the Utility's nuclear decommissioning trusts:

(in millions)	Amortized Cost	Total Unrealized Gains	Total Unrealized Losses	Total Fair Value(1)
As of December, 2012				
Money market investments	$ 21	$ —	$ —	$ 21
Equity securities				
U.S.	331	618	—	949
Non-U.S.	199	181	(1)	379
Debt securities				
U.S. government and agency securities	723	97	—	820
Municipal securities	56	4	(1)	59
Other fixed-income securities	168	5	—	173
Total	**$ 1,498**	**$ 905**	**$ (2)**	**$ 2,401**
As of December 31, 2011				
Money market investments	$ 24	$ —	$ —	$ 24
Equity securities				
U.S.	334	518	(3)	849
Non-U.S.	194	131	(2)	323
Debt securities				
U.S. government and agency securities	774	102	—	876
Municipal securities	56	2	—	58
Other fixed-income securities	96	3	—	99
Total	**$ 1,478**	**$ 756**	**$ (5)**	**$ 2,229**

(1) Excludes $240 million and $188 million at December 31, 2012 and December 31, 2011, respectively, primarily related to deferred taxes on appreciation of investment value.

The fair value of debt securities by contractual maturity is as follows:

(in millions)	As of December 31, 2012
Less than 1 year	$ 5
1 - 5 years	456
5 - 10 years	218
More than 10 years	373
Total maturities of debt securities	**$ 1,052**

The following table provides a summary of activity for the debt and equity securities:

(in millions)	2012	2011	2010
Proceeds from sales and maturities of nuclear decommissioning trust investments	$ 1,133	$ 1,928	$ 1,405
Gross realized gains on sales of securities held as available-for-sale	19	43	42
Gross realized losses on sales of securities held as available-for-sale	(17)	(30)	(11)

NOTE 12: EMPLOYEE BENEFIT PLANS

PG&E Corporation and the Utility provide a non-contributory defined benefit pension plan for eligible employees, as well as contributory postretirement medical plans for retirees and their eligible dependents, and non-contributory postretirement life insurance plans for eligible employees and retirees. The trusts underlying certain of these plans are qualified trusts under the Internal Revenue Code of 1986, as amended ("Code"). If certain conditions are met, PG&E Corporation and the Utility can deduct payments made to the qualified trusts, subject to certain Code limitations. PG&E Corporation and the Utility use a December 31 measurement date for all plans.

PG&E Corporation's and the Utility's funding policy is to contribute tax-deductible amounts, consistent with applicable regulatory decisions and federal minimum funding requirements. Based upon current assumptions and available information, the Utility's minimum funding requirements related to its pension plans was zero.

Change in Plan Assets, Benefit Obligations, and Funded Status

The following tables show the reconciliation of changes in plan assets, benefit obligations, and the plans' aggregate funded status for pension benefits and other benefits for PG&E Corporation during 2012 and 2011:

Pension Benefits

(in millions)	2012	2011
Change in plan assets:		
Fair value of plan assets at January 1	$ 10,993	$ 10,250
Actual return on plan assets	1,488	1,016
Company contributions	282	230
Benefits and expenses paid	(622)	(503)
Fair value of plan assets at December 31	$ 12,141	$ 10,993
Change in benefit obligation:		
Projected benefit obligation at January 1	$ 14,000	$ 12,071
Service cost for benefits earned	396	320
Interest cost	658	660
Actuarial loss	1,099	1,450
Plan amendments	9	—
Transitional costs	1	2
Benefits and expenses paid	(622)	(503)
Projected benefit obligation at December 31(1)	$ 15,541	$ 14,000
Funded status:		
Current liability	$ (6)	$ (5)
Noncurrent liability	(3,394)	(3,002)
Accrued benefit cost at December 31	$ (3,400)	$ (3,007)

(1) PG&E Corporation's accumulated benefit obligation was $13,778 million and $12,285 million at December 31, 2012 and 2011, respectively.

NOTE 12: EMPLOYEE BENEFIT PLANS (Continued)

Other Benefits

(in millions)	2012	2011
Change in plan assets:		
Fair value of plan assets at January 1	**$ 1,491**	**$ 1,337**
Actual return on plan assets	191	95
Company contributions	149	137
Plan participant contribution	55	52
Benefits and expenses paid	(128)	(130)
Fair value of plan assets at December 31	**$ 1,758**	**$ 1,491**
Change in benefit obligation:		
Benefit obligation at January 1	**$ 1,885**	**$ 1,755**
Service cost for benefits earned	49	42
Interest cost	83	91
Actuarial loss	(23)	63
Plan amendments	5	—
Benefits paid	(119)	(130)
Federal subsidy on benefits paid	5	12
Plan participant contributions	55	52
Benefit obligation at December 31	**$ 1,940**	**$ 1,885**
Funded status:		
Noncurrent liability	$ (181)	$ (394)
Accrued benefit cost at December 31	**$ (181)**	**$ (394)**

There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

During 2012, the Utility's defined benefit pension plan was amended to include a new cash balance benefit formula. Eligible employees hired after December 31, 2012 will participate in the cash balance benefit. Eligible employees hired before January 1, 2013 will have a one-time opportunity to elect to participate in the cash balance benefit going forward, beginning on January 1, 2014 or to continue participating in the existing defined benefit plan. As long as pension benefit costs continue to be recoverable through customer rates, PG&E Corporation and the Utility anticipate that this amendment will have no impact on net income.

NOTE 12: EMPLOYEE BENEFIT PLANS (Continued)

Components of Net Periodic Benefit Cost

Net periodic benefit cost as reflected in PG&E Corporation's Consolidated Statements of Income for 2012, 2011, and 2010 was as follows:

Pension Benefits

(in millions)	2012	2011	2010
Service cost for benefits earned	$ 396	$ 320	$ 279
Interest cost	658	660	645
Expected return on plan assets	(598)	(669)	(624)
Amortization of prior service cost	20	34	53
Amortization of unrecognized loss	123	50	44
Net periodic benefit cost	**599**	**395**	**397**
Less: transfer to regulatory account[1]	(301)	(139)	(233)
Total	**$ 298**	**$ 256**	**$ 164**

[1] The Utility recorded $301 million, $139 million, and $233 million for the years ended December 31, 2012, 2011, and 2010, respectively, to a regulatory account as the amounts are probable of recovery from customers in future rates

Other Benefits

(in millions)	2012	2011	2010
Service cost for benefits earned	$ 49	$ 42	$ 36
Interest cost	83	91	88
Expected return on plan assets	(77)	(82)	(74)
Amortization of transition obligation	24	26	26
Amortization of prior service cost	25	27	25
Amortization of unrecognized loss (gain)	6	4	3
Net periodic benefit cost	**$ 110**	**$ 108**	**$ 104**

There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

Components of Accumulated Other Comprehensive Income

PG&E Corporation and the Utility record the net periodic benefit cost for pension benefits and other benefits as a component of accumulated other comprehensive income, net of tax. Net periodic benefit cost is composed of unrecognized prior service costs, unrecognized gains and losses, and unrecognized net transition obligations as components of accumulated other comprehensive income, net of tax.

Regulatory adjustments are recorded in the Consolidated Statements of Income and Consolidated Balance Sheets to reflect the difference between pension expense or income calculated in accordance with GAAP for accounting purposes and pension expense or income for ratemaking, which is based on a funding approach. A regulatory adjustment is also recorded for the amounts that would otherwise be charged to accumulated other comprehensive income for the pension benefits related to the Utility's defined benefit pension plan. The Utility would record a regulatory liability for a portion of the credit balance in accumulated other comprehensive income, should the other benefits be in an overfunded position. However, this recovery mechanism does not allow the Utility to record a regulatory asset for an underfunded position related to other benefits. Therefore, the charge remains in accumulated other comprehensive income (loss) for other benefits.

NOTE 12: EMPLOYEE BENEFIT PLANS (Continued)

The estimated amounts that will be amortized into net periodic benefit costs for PG&E Corporation in 2013 are as follows:

Pension Benefit

(in millions)	
Unrecognized prior service cost	$ 20
Unrecognized net loss	110
Total	**$ 130**

Other Benefits

(in millions)	
Unrecognized prior service cost	$ 24
Unrecognized net loss	6
Total	**$ 30**

There were no material differences between the estimated amounts that will be amortized into net periodic benefit costs for PG&E Corporation and the Utility.

Valuation Assumptions

The following actuarial assumptions were used in determining the projected benefit obligations and the net periodic benefit costs. The following weighted average year-end assumptions were used in determining the plans' projected benefit obligations and net benefit cost.

	Pension Benefits			Other Benefits		
	December 31,			December 31,		
	2012	2011	2010	2012	2011	2010
Discount rate	3.98%	4.66%	5.42%	3.75 - 4.08%	4.41 - 4.77%	5.11 - 5.56%
Average rate of future compensation increases	4.00%	5.00%	5.00%	—	—	—
Expected return on plan assets	5.40%	5.50%	6.60%	2.90 - 6.10%	4.40 - 5.50%	5.20 - 6.60%

The assumed health care cost trend rate as of December 31, 2012 was 7.5%, decreasing gradually to an ultimate trend rate in 2018 and beyond of approximately 5%. A one-percentage-point change in assumed health care cost trend rate would have the following effects:

(in millions)	One-Percentage-Point Increase	One-Percentage-Point Decrease
Effect on postretirement benefit obligation	$ 108	$ (111)
Effect on service and interest cost	8	(8)

Expected rates of return on plan assets were developed by determining projected stock and bond returns and then applying these returns to the target asset allocations of the employee benefit plan trusts, resulting in a weighted average rate of return on plan assets. Returns on fixed-income debt investments were projected based on real maturity and credit spreads added to a long-term inflation rate. Returns on equity investments were estimated based on estimates of dividend yield and real earnings growth added to a long-term inflation rate. For the pension plan, the assumed return of 5.4% compares to a ten-year actual return of 10.2%. The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of over approximately 648 Aa-grade

NOTE 12: EMPLOYEE BENEFIT PLANS (Continued)

non-callable bonds at December 31, 2012. This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension benefits and other benefit obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

The difference between actual and expected return on plan assets is included in unrecognized gain (loss), and is considered in the determination of future net periodic benefit income (cost). The actual return on plan assets in 2011 exceeded expectations due to a higher than expected return on fixed-income debt investments. The actual return on plan assets in 2012 was in line with expectations.

Investment Policies and Strategies

The financial position of PG&E Corporation's and the Utility's funded employee benefit plans is driven by the relationship between plan assets and liabilities. As noted above, the funded status is the difference between the fair value of plan assets and projected benefit obligations. Volatility in funded status occurs when asset values change differently from liability values and can result in fluctuations in costs for financial reporting, as well as the amount of minimum contributions required under the Employee Retirement Income Security Act of 1974, as amended ("ERISA"). PG&E Corporation's and the Utility's investment policies and strategies are designed to increase the ratio of trust assets to plan liabilities at an acceptable level of funded status volatility.

Interest rate, credit, and equity risk are the key determinants of PG&E Corporation's and the Utility's funded status volatility. In addition to affecting the trust's fixed-income portfolio market values, interest rate changes also influence liability valuations as discount rates move with current bond yields. To manage this risk, PG&E Corporation's and the Utility's trusts hold significant allocations to fixed-income investments that include U.S. government securities, corporate securities, and other fixed-income securities. Although they contribute to funded status volatility, equity investments are held to reduce long-term funding costs due to their higher expected return. The equity investment allocation is implemented through portfolios that include common stock and commingled funds across multiple industry sectors. Real assets and absolute return investments are held to diversify the trust's holdings in equity and fixed-income investments by exhibiting returns with low correlation to the direction of these markets. Real assets include commodities futures, global real estate investment trusts ("REITS"), global listed infrastructure equities, and private real estate funds. Absolute return investments include hedge fund portfolios.

Over the last three years, target allocations for equity investments have generally declined in favor of longer-maturity fixed-income investments and real assets as a means of dampening future funded status volatility. In 2012, equity index futures were added to maintain existing equity exposure while adding exposure to fixed-income securities. Historically, the equity investment allocation was implemented through diversified U.S. equity, non-U.S. equity, and global portfolios. In 2012, the U.S. equity and non-U.S. equity allocations were eliminated and became a combined global equity allocation.

In accordance with the pension plan's investment guidelines, derivative instruments such as equity-index futures contracts are used primarily to maintain equity and fixed income portfolio exposure consistent with the investment policy and to rebalance the fixed income/equity allocation of the pension's portfolio. Foreign currency exchange contracts are also used to hedge a portion of the currency of the global equity investments.

PG&E Corporation and the Utility apply a risk management framework for managing the risks associated with employee benefit plan trust assets. The guiding principles of this risk management framework are the clear articulation of roles and responsibilities, appropriate delegation of authority, and proper accountability and documentation. Trust investment policies and investment manager guidelines include provisions designed to ensure prudent diversification, manage risk through appropriate use of physical direct asset holdings and derivative securities, and identify permitted and prohibited investments.

NOTE 12: EMPLOYEE BENEFIT PLANS (Continued)

The target asset allocation percentages for major categories of trust assets for pension and other benefit plans are as follows:

	Pension Benefits			Other Benefits		
	2013	2012	2011	2013	2012	2011
Global equity securities	25%	35%	5%	28%	38%	3%
U.S. equity securities	—%	—%	26%	—%	—%	28%
Non-U.S. equity securities	—%	—%	14%	—%	—%	15%
Absolute return	5%	5%	5%	4%	4%	4%
Real assets	10%	10%	—%	8%	8%	—%
Extended fixed-income securities	3%	3%	—%	—%	—%	—%
Fixed-income securities	57%	47%	50%	60%	50%	50%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

NOTE 12: EMPLOYEE BENEFIT PLANS (Continued)

Fair Value Measurements

The following tables present the fair value of plan assets for pension and other benefits plans by major asset category at December 31, 2012 and 2011.

	Fair Value Measurements At December 31,							
	2012				2011			
(in millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Pension Benefits:								
Money market investments	$ 112	$ —	$ —	$ 112	$ 51	$ —	$ —	$ 51
U.S. equity securities	—	—	—	—	273	2,161	—	2,434
Non-U.S. equity securities	—	—	—	—	131	1,363	—	1,494
Global equity securities	402	3,017	—	3,419	—	197	—	197
Absolute return	—	—	513	513	—	—	487	487
Real assets	525	—	285	810	522	—	65	587
Fixed-income securities:								
U.S. government	1,576	139	—	1,715	1,224	172	—	1,396
Corporate	3	4,275	611	4,889	2	3,083	585	3,670
Other	—	576	—	576	1	688	—	689
Total	$ 2,618	$ 8,007	$ 1,409	$ 12,034	$ 2,204	$ 7,664	$ 1,137	$ 11,005
Other Benefits:								
Money market investments	$ 77	$ —	$ —	$ 77	$ 48	$ —	$ —	$ 48
U.S. equity securities	—	—	—	—	86	222	—	308
Non-U.S. equity securities	—	—	—	—	79	108	—	187
Global equity securities	118	397	—	515	—	19	—	19
Absolute return	—	—	49	49	—	—	47	47
Real assets	68	—	28	96	31	—	6	37
Fixed-income securities:								
U.S. government	148	5	—	153	151	—	—	151
Corporate	9	795	1	805	—	681	1	682
Other	—	38	—	38	1	44	—	45
Total	$ 420	$ 1,235	$ 78	$ 1,733	$ 396	$ 1,074	$ 54	$ 1,524
Total plan assets at fair value				$ 13,767				$ 12,529

In addition to the total plan assets disclosed at fair value in the table above, the trusts had other net assets of $132 million and other net liabilities of $45 million at December 31, 2012 and 2011, respectively. These net assets and net liabilities were comprised primarily of cash, accounts receivable, accounts payable, and deferred taxes.

NOTE 12: EMPLOYEE BENEFIT PLANS (Continued)

Valuation Techniques

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the table above. All investments that are valued using a net asset value per share can be redeemed quarterly with a notice not to exceed 90 days.

Money Market Investments

Money market investments consist primarily of commingled funds of U.S. government short-term securities that are considered Level 1 assets and valued at the net asset value of $1 per unit. The number of units held by the plan fluctuates based on the unadjusted price changes in active markets for the funds' underlying assets.

Equity Securities

The global equity categories include equity investments in common stock and equity-index futures, and commingled funds comprised of equity across multiple industries and regions of the world. Equity investments in common stock are actively traded on public exchanges and are therefore considered Level 1 assets. These equity investments are generally valued based on unadjusted prices in active markets for identical securities. Equity-index futures are valued based on unadjusted prices in active markets and are Level 1 assets. Collateral posted related to these futures consist of money market investments that are considered Level 1 assets. Commingled funds are valued using a net asset value per share and are maintained by investment companies for large institutional investors and are not publicly traded. Commingled funds are comprised primarily of underlying equity securities that are publicly traded on exchanges, and price quotes for the assets held by these funds are readily observable and available. Commingled funds are categorized as Level 2 assets.

Absolute Return

The absolute return category includes portfolios of hedge funds that are valued using a net asset value per share based on a variety of proprietary and non-proprietary valuation methods, including unadjusted prices for publicly-traded securities in active markets. Hedge funds are considered Level 3 assets.

Real Assets

The real asset category includes portfolios of commodities, commodities futures, global REITS, global listed infrastructure equities, and private real estate funds. The commodities, commodities futures, global REITS, and global listed infrastructure equities are actively traded on a public exchange and are therefore considered Level 1 assets. Collateral posted related to the commodities futures consist of money market investments that are considered Level 1 assets. Private real estate funds are valued using a net asset value per share derived using appraisals, pricing models, and valuation inputs that are unobservable and are considered Level 3 assets.

Fixed-Income

The fixed-income category includes U.S. government securities, corporate securities, and other fixed-income securities.

U.S. government fixed-income primarily consists of U.S. Treasury notes and U.S. government bonds that are valued based on quoted market prices or evaluated pricing data for similar securities adjusted for observable differences. These securities are categorized as Level 1 or Level 2 assets.

Corporate fixed-income primarily includes investment grade bonds of U.S. issuers across multiple industries that are valued based on a compilation of primarily observable information or broker quotes in non-active markets. The fair value of corporate bonds is determined using recently executed transactions, market price quotations (where observable), bond spreads or credit default swap spreads obtained from independent external parties such as vendors and brokers adjusted for any basis difference between cash and derivative instruments. These securities are classified as Level 2 assets. Corporate fixed-income also includes commingled funds that are valued using a net asset value per share and are comprised of corporate debt instruments. Commingled funds are considered Level 2 assets. Corporate

NOTE 12: EMPLOYEE BENEFIT PLANS (Continued)

fixed income also includes insurance contracts for deferred annuities. These investments are valued using a net asset value per share using pricing models and valuation inputs that are unobservable and are considered Level 3 assets.

Other fixed-income primarily includes pass-through and asset-backed securities. Pass-through securities are valued based on benchmark yields created using observable market inputs and are Level 2 assets. Asset-backed securities are primarily valued based on broker quotes and are considered Level 2 assets. Other fixed-income also includes municipal bonds and index futures. Collateral posted related to the index futures consist of money market investments that are considered Level 1 assets. Municipal bonds are valued based on a compilation of primarily observable information or broker quotes in non-active markets and are considered Level 2 assets. Futures are valued based on unadjusted prices in active markets and are Level 1 assets.

Transfers Between Levels

PG&E Corporation and the Utility recognize any transfers between levels in the fair value hierarchy as of the end of the reporting period. As shown in the table below, transfers out of Level 3 represent assets that were previously classified as Level 3 for which the lowest significant input became observable during the period. No significant transfers between Levels 1 and 2 occurred in the years ended December 31, 2012 and 2011.

Level 3 Reconciliation

The following table is a reconciliation of changes in the fair value of instruments for pension and other benefit plans that have been classified as Level 3 for the years ended December 31, 2012 and 2011:

	Pension Benefits				
(in millions)	**Absolute Return**	**Corporate Fixed-Income**	**Other Fixed-Income**	**Real Assets**	**Total**
Balance as of January 1, 2011	$ 494	$ 549	$ 120	$ —	**$ 1,163**
Actual return on plan assets:					
Relating to assets still held at the reporting date	5	57	(2)	—	**60**
Relating to assets sold during the period	2	—	1	—	**3**
Purchases, issuances, sales, and settlements					
Purchases	—	14	2	65	**81**
Settlements	(14)	(35)	(58)	—	**(107)**
Transfers out of Level 3	—	—	(63)	—	**(63)**
Balance as of December 31, 2011	**$ 487**	**$ 585**	**$ —**	**$ 65**	**$ 1,137**
Actual return on plan assets:					
Relating to assets still held at the reporting date	26	28	—	12	**66**
Relating to assets sold during the period	—	(1)	—	—	**(1)**
Purchases, issuances, sales, and settlements					
Purchases	—	12	—	208	**220**
Settlements	—	(13)	—	—	**(13)**
Balance as of December 31, 2012	**$ 513**	**$ 611**	**$ —**	**$ 285**	**$ 1,409**

NOTE 12: EMPLOYEE BENEFIT PLANS (Continued)

	Other Benefits				
(in millions)	**Absolute Return**	**Corporate Fixed-Income**	**Other Fixed-Income**	**Real Assets**	**Total**
Balance as of January 1, 2011	$ 47	$ 129	$ 10	—	$ **186**
Actual return on plan assets:					
Relating to assets still held at the reporting date	1	16	—	—	**17**
Relating to assets sold during the period	—	(2)	—	—	**(2)**
Purchases, issuances, sales, and settlements					
Purchases	—	34	—	6	**40**
Settlements	(1)	(30)	(5)	—	**(36)**
Transfers out of Level 3	—	(146)	(5)	—	**(151)**
Balance as of December 31, 2011	**$ 47**	**$ 1**	**$ —**	**$ 6**	**$ 54**
Actual return on plan assets:					
Relating to assets still held at the reporting date	2	—	—	1	**3**
Relating to assets sold during the period	—	—	—	—	**—**
Purchases, issuances, sales, and settlements					
Purchases	—	1	—	21	**22**
Settlements	—	(1)	—	—	**(1)**
Balance as of December 31, 2012	**$ 49**	**$ 1**	**$ —**	**$ 28**	**$ 78**

There were no transfers out of Level 3 in 2012.

Cash Flow Information

Employer Contributions

PG&E Corporation and the Utility contributed $282 million to the pension benefit plans and $149 million to the other benefit plans in 2012. These contributions are consistent with PG&E Corporation's and the Utility's funding policy, which is to contribute amounts that are tax-deductible and consistent with applicable regulatory decisions and federal minimum funding requirements. None of these pension or other benefits were subject to a minimum funding requirement requiring a cash contribution in 2012. The Utility's pension benefits met all the funding requirements under ERISA. PG&E Corporation and the Utility expect to make total contributions of approximately $327 million and $109 million to the pension plan and other postretirement benefit plans, respectively, for 2013.

Benefits Payments and Receipts

As of December 31, 2012, the estimated benefits PG&E Corporation is expected to pay and federal subsidies it is estimated to receive in each of the next five fiscal years, and in aggregate for the five fiscal years thereafter for PG&E Corporation, are as follows:

(in millions)	**Pension**	**Other**	**Federal Subsidy**
2013	$ 581	$ 108	$ (6)
2014	618	112	(7)
2015	656	115	(7)
2016	695	119	(8)
2017	732	124	(8)
2018 - 2022	4,172	662	(42)

NOTE 12: EMPLOYEE BENEFIT PLANS (Continued)

There were no material differences between the estimated benefits expected to be paid by PG&E Corporation and paid by the Utility for the years presented above. There were no material differences between the estimated subsidies expected to be received by PG&E Corporation and received by the Utility for the years presented above.

Defined Contribution Benefit Plans

PG&E Corporation sponsors employee retirement savings plans, including a 401(k) defined contribution savings plan. These plans are qualified under applicable sections of the Code and provide for tax-deferred salary deductions, after-tax employee contributions, and employer contributions. Employer contribution expense reflected in PG&E Corporation's Consolidated Statements of Income was as follows:

(in millions)	
Year ended December 31,	
2012	$ 67
2011	65
2010	56

There were no material differences between the employer contribution expense for PG&E Corporation and the Utility for the years presented above.

NOTE 13: RESOLUTION OF REMAINING CHAPTER 11 DISPUTED CLAIMS

Various electricity suppliers filed claims in the Utility's Chapter 11 proceeding seeking payment for energy supplied to the Utility's customers through the wholesale electricity markets operated by the CAISO and the California Power Exchange ("PX") between May 2000 and June 2001. These claims, which the Utility disputes, are being addressed in various FERC and judicial proceedings in which the State of California, the Utility, and other electricity purchasers are seeking refunds from electricity suppliers, including governmental entities, for overcharges incurred in the CAISO and the PX wholesale electricity markets during this period. It is uncertain when all these FERC and judicial proceedings will be finally resolved.

While the FERC and judicial proceedings are pending, the Utility has pursued, and continues to pursue, settlements with electricity suppliers. The Utility entered into a number of settlement agreements with various electricity suppliers to resolve some of these disputed claims and to resolve the Utility's refund claims against these electricity suppliers. These settlement agreements provide that the amounts payable by the parties are, in some instances, subject to adjustment based on the outcome of the various refund offset and interest issues being considered by the FERC. Additional settlement discussions with other electricity suppliers are ongoing. Any net refunds, claim offsets, or other credits that the Utility receives from electricity suppliers through resolution of the remaining disputed claims, either through settlement or through the conclusion of the various FERC and judicial proceedings, are refunded to customers through rates in future periods.

On April 10, 2012, the Utility received from the PX a letter stating the mutual intent of the CAISO and the PX to offset the Utility's remaining disputed claims with its accounts receivable from the CAISO and the PX. Accordingly, the Utility has presented the net amount of remaining disputed claims and accounts receivable on the Consolidated Balance Sheets at December 31, 2012, reflecting its intent and right to offset these amounts. At December 31, 2011, $494 million was included within accounts receivable—other on the Consolidated Balance Sheets.

The following table presents the changes in the remaining net disputed claims liability, which includes interest:

(in millions)	
Balance at December 31, 2011	$ 848
Interest accrued	27
Less: supplier settlements	(33)
Balance at December 31, 2012	**$ 842**

NOTE 13: RESOLUTION OF REMAINING CHAPTER 11 DISPUTED CLAIMS (Continued)

At December 31, 2012, the remaining net disputed claims liability consisted of $157 million of remaining net disputed claims (classified on the Consolidated Balance Sheets within accounts payable—disputed claims and customer refunds) and $685 million of accrued interest (classified on the Consolidated Balance Sheets within interest payable).

At December 31, 2012 and December 31, 2011, the Utility held $291 million and $320 million, respectively, in escrow, including earned interest, for payment of the remaining net disputed claims liability. These amounts are included within restricted cash on the Consolidated Balance Sheets.

Interest accrues on the remaining net disputed claims at the FERC-ordered rate, which is higher than the rate earned by the Utility on the escrow balance. Although the Utility has been collecting the difference between the accrued interest and the earned interest from customers in rates, these collections are not held in escrow. If the amount of accrued interest is greater than the amount of interest ultimately determined to be owed on the remaining net disputed claims, the Utility would refund to customers any excess interest collected. The amount of any interest that the Utility may be required to pay will depend on the final determined amount of the remaining net disputed claims and when such interest is paid.

NOTE 14: RELATED PARTY AGREEMENTS AND TRANSACTIONS

The Utility and other subsidiaries provide and receive various services to and from their parent, PG&E Corporation, and among themselves. The Utility and PG&E Corporation exchange administrative and professional services in support of operations. Services provided directly to PG&E Corporation by the Utility are priced at the higher of fully loaded cost (i.e., direct cost of good or service and allocation of overhead costs) or fair market value, depending on the nature of the services. Services provided directly to the Utility by PG&E Corporation are generally priced at the lower of fully loaded cost or fair market value, depending on the nature and value of the services. PG&E Corporation also allocates various corporate administrative and general costs to the Utility and other subsidiaries using agreed-upon allocation factors, including the number of employees, operating and maintenance expenses, total assets, and other cost allocation methodologies. Management believes that the methods used to allocate expenses are reasonable and meet the reporting and accounting requirements of its regulatory agencies.

The Utility's significant related party transactions were as follows:

	Year Ended December 31,		
(in millions)	**2012**	**2011**	**2010**
Utility revenues from:			
Administrative services provided to PG&E Corporation	$ 7	$ 6	$ 7
Utility expenses from:			
Administrative services received from PG&E Corporation	$ 50	$ 49	$ 55
Utility employee benefit due to PG&E Corporation	51	33	27

At December 31, 2012 and 2011, the Utility had receivables of $19 million and $21 million, respectively, from PG&E Corporation included in accounts receivable—other and other noncurrent assets—other on the Utility's Consolidated Balance Sheets, and payables of $17 million and $13 million, respectively, to PG&E Corporation included in accounts payable—other on the Utility's Consolidated Balance Sheets.

NOTE 15: COMMITMENTS AND CONTINGENCIES

PG&E Corporation and the Utility have substantial financial commitments in connection with agreements entered into to support the Utility's operating activities. PG&E Corporation and the Utility also have significant contingencies arising from their operations, including contingencies related to regulatory proceedings, nuclear operations, legal matters, environmental remediation, and guarantees.

NOTE 15: COMMITMENTS AND CONTINGENCIES (Continued)

Commitments

Third-Party Power Purchase Agreements

As part of the ordinary course of business, the Utility enters into various agreements to purchase power and electric capacity. The price of purchased power may be fixed or variable. Variable pricing is generally based on the current market price of either natural gas or electricity at the date of delivery.

The costs incurred for all power purchases were as follows:

(in millions)	2012	2011	2010
Qualifying facilities[1]	$ 779	$ 1,069	$ 1,164
Renewable energy contracts	815	622	573
Other power purchase agreements	661	690	657

(1) Costs incurred include $286, $297, and $321 attributable to renewable energy contracts with qualifying facilities at December 31, 2012, 2011 and 2010, respectively.

Qualifying Facility Power Purchase Agreements—Under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), electric utilities are required to purchase energy and capacity from independent power producers with generation facilities that meet the statutory definition of a qualifying facility ("QF"). QFs include small power production facilities whose primary energy sources are co-generation facilities that produce combined heat and power and renewable generation facilities. To implement the purchase requirements of PURPA, the CPUC required California investor-owned electric utilities to enter into long-term power purchase agreements with QFs and approved the applicable terms and conditions, prices, and eligibility requirements. These agreements require the Utility to pay for energy and capacity. Energy payments are based on the QF's electrical output and CPUC-approved energy prices. Capacity payments are based on the QF's total available capacity and contractual capacity commitment. Capacity payments may be adjusted if the QF exceeds or fails to meet performance requirements specified in the applicable power purchase agreement.

As of December 31, 2012, the Utility had agreements with 180 QFs that are in operation, which expire at various dates between 2013 and 2028.

Renewable Energy Power Purchase Agreements—The Utility has entered into various contracts to purchase renewable energy to help the Utility meet California's current renewable portfolio standard ("RPS") requirement. California's RPS program gradually increases the amount of renewable energy that load-serving entities, such as the Utility, must deliver to their customers from an average of at least 20% of their total retail sales in the years 2011-2013 to 33% of their total retail sales in 2021 and thereafter. Generally these agreements include an energy payment based on the electrical output and a fixed price per Megawatt-hour. The Utility's obligations under a significant portion of these agreements are contingent on the third party's construction of new generation facilities. The table below includes arrangements that have been approved by the CPUC and have completed major milestones with respect to construction. The Utility's commitments for energy payments under these renewable energy agreements are expected to grow significantly, assuming that the facilities are developed timely.

Other Power Purchase Agreements—The Utility has entered into several power purchase agreements for conventional generation resources, which include tolling agreements and resource adequacy agreements. The Utility's obligation under a portion of these agreements is contingent on the third parties' development of new generation facilities to provide capacity and energy products to the Utility under tolling agreements. The Utility also has agreements with various irrigation districts and water agencies to purchase hydroelectric power.

NOTE 15: COMMITMENTS AND CONTINGENCIES (Continued)

At December 31, 2012, the undiscounted future expected obligations under power purchase agreements were as follows:

(in millions)	Qualifying Facility	Renewable (Other than QF)	Other	Total Payments
2013	$ 892	$ 1,356	$ 846	$ 3,094
2014	914	1,843	677	3,434
2015	727	2,038	649	3,414
2016	618	2,054	626	3,298
2017	490	2,053	597	3,140
Thereafter	2,238	30,958	3,322	36,518
Total	**$ 5,879**	**$ 40,302**	**$ 6,717**	**$ 52,898**

Some of the power purchase agreements that the Utility entered into with independent power producers that are QFs are treated as capital leases. The following table shows the future fixed capacity payments due under the QF agreements that are treated as capital leases. (These amounts are also included in the table above.) The fixed capacity payments are discounted to their present value in the table below using the Utility's incremental borrowing rate at the inception of the leases. The amount of this discount is shown in the table below as the amount representing interest.

(in millions)	
2013	$ 35
2014	27
2015	24
2016	22
2017	18
Thereafter	20
Total fixed capacity payments	**146**
Less: amount representing interest	21
Present value of fixed capacity payments	**$ 125**

Minimum lease payments associated with the lease obligations are included in cost of electricity on PG&E Corporation's and the Utility's Consolidated Statements of Income. The timing of the recognition of the lease expense conforms to the ratemaking treatment for the Utility's recovery of the cost of electricity. The QF agreements that are treated as capital leases expire between April 2014 and September 2021.

The present value of the fixed capacity payments due under these agreements is recorded on PG&E Corporation's and the Utility's Consolidated Balance Sheets. At December 31, 2012 and 2011, current liabilities—other included $29 million and $36 million, respectively, and noncurrent liabilities—other included $96 million and $212 million, respectively. The corresponding assets at December 31, 2012 and 2011 of $125 million and $248 million including accumulated amortization of $148 million and $160 million, respectively are included in property, plant, and equipment on PG&E Corporation's and the Utility's Consolidated Balance Sheets.

Natural Gas Supply, Transportation, and Storage Commitments

The Utility purchases natural gas directly from producers and marketers in both Canada and the United States to serve its core customers and to fuel its owned-generation facilities. The Utility also contracts for natural gas transportation from the points at which the Utility takes delivery (typically in Canada, the US Rocky Mountain supply area, and the southwestern United States) to the points at which the Utility's natural gas transportation system begins. In addition, the Utility has contracted for natural gas storage services in northern California in order to more reliably meet customers' loads.

NOTE 15: COMMITMENTS AND CONTINGENCIES (Continued)

At December 31, 2012, the Utility's undiscounted future expected payment obligations for natural gas supplies, transportation and storage were as follows:

(in millions)	
2013	$ 707
2014	208
2015	192
2016	152
2017	108
Thereafter	865
Total	**$ 2,232**

Costs incurred for natural gas purchases, natural gas transportation services, and natural gas storage, which include contracts less than 1 year, amounted to $1.3 billion in 2012, $1.8 billion in 2011, and $1.6 billion in 2010.

Nuclear Fuel Agreements

The Utility has entered into several purchase agreements for nuclear fuel. These agreements have terms ranging from one to 13 years and are intended to ensure long-term nuclear fuel supply. The contracts for uranium and for conversion and enrichment services provide for 100% coverage of reactor requirements through 2020, while contracts for fuel fabrication services provide for 100% coverage of reactor requirements through 2017. The Utility relies on a number of international producers of nuclear fuel in order to diversify its sources and provide security of supply. Pricing terms are also diversified, ranging from market-based prices to base prices that are escalated using published indices.

At December 31, 2012, the undiscounted future expected payment obligations for nuclear fuel were as follows:

(in millions)	
2013	$ 113
2014	128
2015	194
2016	147
2017	148
Thereafter	878
Total	**$ 1,608**

Payments for nuclear fuel amounted to $118 million in 2012, $77 million in 2011, and $144 million in 2010.

Other Commitments

The Utility has other commitments relating to operating leases. At December 31, 2012, the future minimum payments related to these commitments were as follows:

(in millions)	
2013	$ 42
2014	37
2015	32
2016	31
2017	24
Thereafter	206
Total	**$ 372**

NOTE 15: COMMITMENTS AND CONTINGENCIES (Continued)

Payments for other commitments relating to operating leases amounted to $32 million in 2012, $27 million in 2011, and $25 million in 2010. PG&E Corporation and the Utility had operating leases on office facilities expiring at various dates from 2013 to 2023. Certain leases on office facilities contain escalation clauses requiring annual increases in rent ranging from 2% to 5%. The rentals payable under these leases may increase by a fixed amount each year, a percentage of increase over base year, or the consumer price index. Most leases contain extension options ranging between one and five years.

Underground Electric Facilities

At December 31, 2012, the Utility was committed to spending approximately $277 million for the conversion of existing overhead electric facilities to underground electric facilities. These funds are conditionally committed depending on the timing of the work, including the schedules of the respective cities, counties, and communications utilities involved. The Utility expects to spend $86 million each year in connection with these projects. Consistent with past practice, the Utility expects that these capital expenditures will be included in rate base as each individual project is completed and that the amount of the capital expenditures will be recoverable from customers through rates.

Contingencies

Legal and Regulatory Contingencies

PG&E Corporation and the Utility are subject to various laws and regulations and, in the normal course of business, PG&E Corporation and the Utility are named as parties in a number of claims and lawsuits. In addition, the Utility can incur penalties for failure to comply with federal, state, or local laws and regulations.

PG&E Corporation and the Utility record a provision for a loss when it is both probable that a loss has been incurred and the amount of the loss can be reasonably estimated. PG&E Corporation and the Utility evaluate the range of reasonably estimated losses and record a provision based on the lower end of the range, unless an amount within the range is a better estimate than any other amount. These accruals, and the estimates of any additional reasonably possible losses (or reasonably possible losses in excess of the amounts accrued), are reviewed quarterly and are adjusted to reflect the impacts of negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. In assessing the amounts related to such contingencies, PG&E Corporation's and the Utility's policy is to exclude anticipated legal costs.

The accrued liability associated with claims and litigation, regulatory proceedings, penalties, and other legal matters (other than the third-party claims, litigation, and investigations related to natural gas matters that are discussed below) totaled $34 million at December 31, 2012 and $52 million at December 31, 2011 and are included in PG&E Corporation's and the Utility's current liabilities—other in the Consolidated Balance Sheets. Except as discussed below, PG&E Corporation and the Utility do not believe that losses associated with legal and regulatory contingencies would have a material impact on their financial condition, results of operations, or cash flows.

Natural Gas Matters

On September 9, 2010, an underground 30-inch natural gas transmission pipeline ("Line 132") owned and operated by the Utility, ruptured in a residential area located in the City of San Bruno, California (the "San Bruno accident"). The ensuing explosion and fire resulted in the deaths of eight people, numerous personal injuries, and extensive property damage. Following the San Bruno accident, various regulatory proceedings, investigations, and lawsuits were commenced. The Natural Transportation Safety Board, an independent review panel appointed by the CPUC, and the CPUC's Safety and Enforcement Division ("SED") completed investigations into the causes of the accident, placing the blame primarily on the Utility.

Pending CPUC Investigations and Enforcement Matters

The CPUC is conducting three investigations pertaining to the Utility's natural gas operations, which are described below. In 2012, the SED issued reports in each of these investigations alleging that the Utility committed numerous violations of applicable laws and regulations and recommending that the CPUC impose penalties on the

NOTE 15: COMMITMENTS AND CONTINGENCIES (Continued)

Utility. (See "Penalties Conclusion" below.) Although the Utility, the SED, and other parties have engaged in settlement discussions in an effort to reach a stipulated outcome to resolve the investigations, the parties have not reached an agreement. PG&E Corporation and the Utility are uncertain whether or when any stipulated outcome might be reached. Any agreement regarding a stipulated outcome would be subject to CPUC approval.

The CPUC has concluded evidentiary hearings in each investigation. The CPUC administrative law judges ("ALJs") who oversee the investigations have adopted a revised procedural schedule, including the dates by which the parties' briefs must be submitted. The ALJs have also permitted the other parties (the City of San Bruno, The Utility Reform Network, and the City and County of San Francisco) to separately address in their opening briefs their allegations against the Utility, if any, in addition to the allegations made by the SED. The ALJs have ordered the SED and other parties to file single coordinated briefs to address potential monetary penalties and remedies (which could include remedial operational or policy measures) for all three investigations by April 26, 2013. After briefing has been completed, the ALJs will issue one or more presiding officer's decisions listing the violations determined to have been committed, the amount of penalties, and any required remedial actions. Based on the revised procedural schedule, one or more presiding officer's decisions will be issued by July 23, 2013. The decisions would become the final decisions of the CPUC thirty days after issuance unless the Utility or another party filed an appeal, or a CPUC commissioner requested review of the decision, within such time.

CPUC Investigation Regarding the Utility's Facilities Records for its Natural Gas Pipelines

In February 2011, the CPUC commenced an investigation pertaining to safety recordkeeping for Line 132, as well as for the Utility's entire gas transmission system. Among other matters, the investigation will determine whether the San Bruno accident would have been preventable by the exercise of safe procedures and /or accurate and technical recordkeeping in compliance with the law. In March 2012, the SED submitted testimony alleging that the Utility committed numerous violations of applicable laws and regulations based on the findings of the SED's records management consultant and an engineering consultant. Among other findings, the consultants' reports concluded that: the Utility's recordkeeping practices have been deficient and have diminished pipeline safety; the San Bruno accident may have been prevented had the Utility managed its records properly over the years; and that the Utility has been operating, and continues to operate, without a functional integrity management program. The Utility submitted testimony to the CPUC that acknowledged that improvements are needed to its asset management system and recordkeeping practices, but disputed many of the SED's findings and allegations. The CPUC concluded evidentiary hearings in this investigation in January 2013. Briefing on the issue of alleged violations is scheduled to be completed on April 19, 2013.

CPUC Investigation Regarding the Utility's Class Location Designations for Pipelines

In November 2011, the CPUC commenced an investigation pertaining to the Utility's operation of its natural gas transmission pipeline system in or near locations of higher population density. Under federal and state regulations, the class location designation of a pipeline is based on the types of buildings, population density, or level of human activity near the segment of pipeline, and is used to determine the maximum allowable operating pressure up to which a pipeline can be operated. In its May 2012 investigative report, the SED cited the Utility's admissions in previous reports to the CPUC that it had failed to classify pipeline segments properly and to document past patrols of transmission lines and concluded that these failures resulted in over three thousand violations of state and federal standards. On July 23, 2012, the Utility submitted testimony in response to the SED's report that acknowledged deficiencies in the Utility's past class location and patrol processes and described the efforts to improve those processes. The CPUC concluded evidentiary hearings in this investigation in September 2012 and briefing on the issue of alleged violations has been completed.

CPUC Investigation Regarding the San Bruno Accident

In January 2012, the CPUC commenced an investigation to determine whether the Utility violated applicable laws and requirements in connection with the San Bruno accident, as alleged by the SED. In its January investigative report, the SED alleged that the San Bruno accident was caused by the Utility's failure to follow accepted industry practice when installing the section of pipe that failed, the Utility's failure to comply with federal pipeline integrity

NOTE 15: COMMITMENTS AND CONTINGENCIES (Continued)

management requirements, the Utility's inadequate record keeping practices, deficiencies in the Utility's data collection and reporting system, the Utility's inadequate procedures to handle emergencies and abnormal conditions, the Utility's deficient emergency response actions after the incident, and a systemic failure of the Utility's corporate culture that emphasized profits over safety. The CPUC stated that the scope of the investigation will include all past operations, practices and other events or courses of conduct that could have led to or contributed to the San Bruno accident, as well as, the Utility's compliance with CPUC orders and resolutions issued since the date of the San Bruno accident.

The Utility submitted testimony to the CPUC that acknowledged its liability for the San Bruno accident and, based on testimony from an expert witness, stated that the likely root cause of the pipeline rupture was: (1) a missing interior weld on the pipe; (2) a ductile tear on the pipe likely caused by a hydrostatic test performed in 1956 at too low a pressure to cause the defective weld to fail; and (3) a fatigue crack on the pipe that grew over time. However, the Utility stated that many of the findings identified in the SED's reports are not deficiencies, or are much less severe than alleged, and do not constitute violations of applicable laws and regulations. The CPUC concluded evidentiary hearings in this investigation in January 2013. Briefing on the issue of alleged violations is scheduled to be completed on April 12, 2013.

Other Potential Enforcement Matters

California gas corporations are required to provide notice to the CPUC of any self-identified or self-corrected violations of certain state and federal regulations related to the safety of natural gas facilities and the corporations' natural gas operating practices. The CPUC has authorized the SED to issue citations and impose penalties based on self-reported violations. In April 2012, the CPUC affirmed a $17 million penalty that had been imposed by the SED based on the Utility's self-report that it failed to conduct periodic leak surveys because it had not included 16 gas distribution maps in its leak survey schedule. (The Utility has paid the penalty and completed all of the missed leak surveys.) As of December 31, 2012, the Utility has submitted 34 self-reports with the CPUC, plus additional follow-up reports. The SED has not yet taken formal action with respect to the Utility's other self-reports. The SED may issue additional citations and impose penalties on the Utility associated with these or future reports that the Utility may file. (See "Penalties Conclusion" below.)

In addition, in July 2012, the Utility reported to the CPUC that it had discovered that its access to some pipelines has been limited by vegetation overgrowth or building structures that encroach upon some of the Utility's gas pipeline rights-of-way. The Utility is undertaking a system-wide effort to identify and remove encroachments from its pipeline rights-of-way over a multi-year period. PG&E Corporation and the Utility are uncertain how this matter will affect the above investigative proceedings related to natural gas operations, or whether additional proceedings or investigations will be commenced that could result in regulatory orders or the imposition of penalties on the Utility.

Penalties Conclusion

The CPUC can impose penalties of up to $20,000 per day, per violation. (For violations that are considered to have occurred on or after January 1, 2012, the statutory penalty has increased to a maximum of $50,000 per day, per violation.) The CPUC has wide discretion to determine the amount of penalties based on the totality of the circumstances, including such factors as the gravity of the violations; the type of harm caused by the violations and the number of persons affected; and the good faith of the entity charged in attempting to achieve compliance, after notification of a violation. The CPUC is also required to consider the appropriateness of the amount of the penalty to the size of the entity charged. The CPUC has historically exercised this wide discretion in determining penalties. The CPUC's delegation of enforcement authority to the SED allows the SED to use these factors in exercising discretion to determine the number of violations, but the SED is required to impose the maximum statutory penalty for each separate violation that the SED finds.

NOTE 15: COMMITMENTS AND CONTINGENCIES (Continued)

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. In determining the amount of penalties the ALJs may consider the testimony of financial consultants engaged by the SED and the Utility. The SED's financial consultant prepared a report concluding that PG&E Corporation could raise approximately $2.25 billion through equity issuances, in addition to equity PG&E Corporation had already forecasted it would issue in 2012, to fund CPUC-imposed penalties on the Utility. The Utility's financial consultant disagreed with this financial analysis and asserted that a fine in excess of financial analysts' expectations, which the consultant's report cited as a mean of $477 million, would make financing more difficult and expensive. The ALJs have scheduled a hearing to be held on March 4 and March 5, 2013 to consider the SED's and Utility's testimony. The SED and other parties are scheduled to file briefs to address potential monetary penalties and remedies in all three investigations by April 26, 2013.

PG&E Corporation and the Utility believe it is probable that the Utility will incur penalties of at least $200 million in connection with these pending investigations and potential enforcement matters and have accrued this amount in their consolidated financial statements. PG&E Corporation and the Utility are unable to make a better estimate of probable losses or estimate the range of reasonably possible losses in excess of the amount accrued due to the many variables that could affect the final outcome of these matters and the ultimate amount of penalties imposed on the Utility could be materially higher than the amount accrued. These variables include how the CPUC and the SED will exercise their discretion in calculating the amount of penalties, including how the total number of violations will be counted; how the duration of the violations will be determined; whether the amount of penalties in each investigation will be determined separately or in the aggregate; how the financial resources testimony submitted by the SED and the Utility will be considered; whether the Utility's costs to perform any required remedial actions will be considered; and whether and how the financial impact of non-recoverable costs the Utility has already incurred, and will continue to incur, to improve the safety and reliability of its pipeline system, will be considered. (See "CPUC Gas Safety Rulemaking Proceeding" below.)

These estimates, and the assumptions on which they are based, are subject to change based on many factors, including rulings, orders, or decisions that may be issued by the ALJs; whether the outcome of the investigations is resolved through a fully litigated process or a stipulated outcome that is approved by the CPUC; whether the SED will take additional action with respect to the Utility's self-reports; and whether the CPUC or the SED takes any action with respect to the encroachment matter described above. Future changes in these estimates or the assumptions on which they are based could have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

CPUC Gas Safety Rulemaking Proceeding

The CPUC is conducting a rulemaking proceeding to adopt new safety and reliability regulations for natural gas transmission and distribution pipelines in California and the related ratemaking mechanisms. On December 20, 2012, the CPUC approved the Utility's proposed pipeline safety enhancement plan (filed in August 2011) to modernize and upgrade its natural gas transmission system but disallowed the Utility's request for rate recovery of a significant portion of plan-related costs the Utility forecasted it would incur over the first phase of the plan (2011 through 2014). The CPUC decision limited the Utility's recovery of capital expenditures to $1.0 billion of the total $1.4 billion requested. Various parties have asked the CPUC to reconsider its decision, arguing that the Utility's cost recovery should be more limited. For 2012, the Utility recorded a $353 million charge to net income for plan-related capital expenditures incurred that are forecasted to exceed the CPUC's authorized levels or that were specifically disallowed. Future disallowed amounts will be charged to net income in the period incurred and could have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

Criminal Investigation

In June 2011, the Utility was notified that representatives from the U.S. Department of Justice, the California Attorney General's Office, and the San Mateo County District Attorney's Office are conducting an investigation of the San Bruno accident. Federal and state authorities have indicated that the Utility is a target of the investigation. The Utility is cooperating with the investigation. PG&E Corporation and the Utility are uncertain whether any criminal charges will be brought against either company or any of their current or former employees. PG&E

NOTE 15: COMMITMENTS AND CONTINGENCIES (Continued)

Corporation and the Utility are unable to estimate the amount (or range of amounts) of reasonably possible losses associated with any civil or criminal penalties that could be imposed on the Utility as a consequence of this investigation.

Third-Party Claims

In addition to the investigations and proceedings discussed above, at December 31, 2012, approximately 140 lawsuits involving third-party claims for personal injury and property damage, including two class action lawsuits, had been filed against PG&E Corporation and the Utility in connection with the San Bruno accident on behalf of approximately 450 plaintiffs. The lawsuits seek compensation for personal injury and property damage, and other relief, including punitive damages. These cases were coordinated and assigned to one judge in the San Mateo County Superior Court. Many of the plaintiffs' claims have been resolved through settlements. The trial of the first group of remaining cases began on January 2, 2013 with pretrial motions and hearings. On January 14, 2013, the court vacated the trial and all pending hearings due to the significant number of cases that have been settled outside of court. The court has urged the parties to settle the remaining cases. As of February 8, 2013, the Utility has entered into settlement agreements to resolve the claims of approximately 140 plaintiffs. It is uncertain whether or when the Utility will be able to resolve the remaining claims through settlement.

At December 31, 2012, the Utility had recorded cumulative charges of $455 million for estimated third-party claims related to the San Bruno accident, including an $80 million charge made during 2012, primarily to reflect settlements and information exchanged by the parties during the settlement and discovery process. The Utility estimates it is reasonably possible that it may incur as much as an additional $145 million for third-party claims, for a total possible loss of $600 million. PG&E Corporation and the Utility are unable to estimate the amount (or range of amounts) of reasonably possible losses associated with punitive damages, if any, related to these matters. The Utility has publicly stated that it is liable for the San Bruno accident and will take financial responsibility to compensate all of the victims for the injuries they suffered as a result of the accident.

The following table presents changes in third-party claims activity since the San Bruno accident in 2010; the balance is included in other current liabilities in PG&E Corporation's and the Utility's Consolidated Balance Sheets:

(in millions)	
Balance at January 1, 2010	$ —
Loss accrued	220
Less: Payments	(6)
Balance at December 31, 2010	214
Additional loss accrued	155
Less: Payments	(92)
Balance at December 31, 2011	277
Additional loss accrued	80
Less: Payments	(211)
Balance at December 31, 2012	**$ 146**

Additionally, the Utility has liability insurance from various insurers who provide coverage at different policy limits that are triggered in sequential order or "layers." Generally, as the policy limit for a layer is exhausted the next layer of insurance becomes available. The aggregate amount of insurance coverage for third-party liability attributable to the San Bruno accident is approximately $992 million in excess of a $10 million deductible. The Utility has recognized cumulative insurance recoveries for third-party claims of $284 million, which included $185 million for 2012 and $99 million for 2011. Although the Utility believes that a significant portion of costs incurred for third-party claims relating to the San Bruno accident will ultimately be recovered through its insurance, it is unable to predict the amount and timing of additional insurance recoveries.

NOTE 15: COMMITMENTS AND CONTINGENCIES (Continued)

Class Action Complaint

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. To state their claims, the plaintiffs cited the SED's January 2012 investigative report of the San Bruno accident that alleged, from 1996 to 2010, the Utility spent less on capital expenditures and operations and maintenance expense for its natural gas transmission operations than it recovered in rates, by $95 million and $39 million, respectively. The SED recommended in that report that the Utility should use such amounts to fund future gas transmission expenditures and operations. Plaintiffs allege that PG&E Corporation and the Utility engaged in unfair business practices in violation of Section 17200 of the California Business and Professions Code ("Section 17200") and claim that this violation also constitutes a violation of California Public Utilities Code Section 2106 ("Section 2106"), which provides a private right of action for violations of the California constitution or state laws by public utilities. Plaintiffs seek restitution and disgorgement under Section 17200 and compensatory and punitive damages under Section 2106.

PG&E Corporation and the Utility contest the plaintiffs' allegations. In January 2013, PG&E Corporation and the Utility requested that the court dismiss the complaint on the grounds that the CPUC has exclusive jurisdiction to adjudicate the issues raised by the plaintiffs' allegations. In the alternative, PG&E Corporation and the Utility requested that the court stay the proceeding until the CPUC investigations described above are concluded. The court has set a hearing on the motion for April 26, 2013. Due to the early stage of this proceeding, PG&E Corporation and the Utility are unable to estimate the amount (or range of amounts) of reasonably possible losses that may be incurred in connection with this matter.

Spent Nuclear Fuel Storage Proceedings

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 to the Utility to dispose of nuclear waste from the Utility's two nuclear generating units at Diablo Canyon and its retired nuclear facility at Humboldt Bay ("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. As of December 31, 2012, the Utility has collected the settlement proceeds from the U.S. Treasury and recorded the amount as a regulatory balancing account. The proceeds will be refunded to customers through rates in future periods. The agreement also allows the Utility to submit annual claims to recover costs incurred in 2011, 2012 and 2013, which the Utility estimates to be approximately $25 million per year. These amounts will also be refunded to customers in future periods. At December 31, 2012, PG&E Corporation and the Utility have not recorded any receivables for annual claims in their Consolidated Balance Sheets. The agreement does not address costs incurred for spent fuel storage after 2013 and such costs could be the subject of 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 nuclear fuel.

Nuclear Insurance

The Utility is a member of Nuclear Electric Insurance Limited ("NEIL") which is a mutual insurer owned by utilities with nuclear facilities. NEIL provides insurance coverage for property damages and business interruption losses incurred by the Utility due to a nuclear event (meaning that nuclear material is released) that occurs at the Utility's two nuclear generating units at Diablo Canyon and the retired Humboldt Bay Unit 3. NEIL provides

NOTE 15: COMMITMENTS AND CONTINGENCIES (Continued)

property damage and business interruption coverage of up to $3.2 billion per nuclear incident ($2.7 billion for property damage and $490 million for business interruption) for Diablo Canyon. In addition, NEIL provides $131 million of coverage for nuclear and non-nuclear property damages at Humboldt Bay Unit 3. (NEIL also provides insurance coverage to the Utility for non-nuclear property damages and business interruption losses at Diablo Canyon, though with significantly lower limits beginning in April 2013.) Under this insurance, if any nuclear generating facility insured by NEIL suffers a catastrophic loss, the Utility may be required to pay an additional premium of up to $44 million per one-year policy term. NRC regulations require that the Utility's property damage insurance policies provide that all proceeds from such insurance be applied, first, to place the plant in a safe and stable condition after an accident and, second, to decontaminate the plant before any proceeds can be used for decommissioning or plant repair.

NEIL policies also provide coverage for damages caused by acts of terrorism at nuclear power plants. Certain acts of terrorism may be "certified" by the Secretary of the Treasury. If damages are caused by certified acts of terrorism, NEIL can obtain compensation from the federal government and will provide up to its full policy limit of $3.2 billion for each insured loss. In contrast, NEIL would treat all non-certified terrorist acts occurring within a 12-month period against one or more commercial nuclear power plants insured by NEIL as one event and the owners of the affected plants would share the $3.2 billion policy limit amount.

Under the Price-Anderson Act, public liability claims that arise from nuclear incidents that occur at Diablo Canyon, and that occur during the transportation of material to and from Diablo Canyon are limited to $12.6 billion. As required by the Price-Anderson Act, the Utility purchased the maximum available public liability insurance of $375 million for Diablo Canyon. The balance of the $12.6 billion of liability protection is provided under a loss-sharing program among utilities owning nuclear reactors. The Utility may be assessed up to $235 million per nuclear incident under this program, with payments in each year limited to a maximum of $35 million per incident. Both the maximum assessment and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due on or before October 29, 2013.

The Price-Anderson Act does not apply to public liability claims that arise from nuclear incidents that occur during shipping of nuclear material from the nuclear fuel enricher to a fuel fabricator or that occur at the fuel fabricator's facility. Such claims are covered by nuclear liability policies purchased by the enricher and the fuel fabricator, as well as by separate supplier's and transporter's insurance policies. The Utility has a separate supplier's and transporter's policy that provides coverage for claims arising from some of these incidents up to a maximum of $375 million per incident.

In addition, the Utility has $53 million of liability insurance for Humboldt Bay Unit 3 and has a $500 million indemnification from the NRC for public liability arising from nuclear incidents, covering liabilities in excess of the $53 million of liability insurance.

If the Utility incurs losses in connection with any of its nuclear generation facilities that are either not covered by insurance or exceed the amount of insurance available, such losses could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

Environmental Remediation Contingencies

The Utility has been, and may be required to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party under federal and 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.

Given the complexities of the legal and regulatory environment and the inherent uncertainties involved in the early stages of a remediation project, the process for estimating remediation liabilities is subjective and requires significant judgment. The Utility records an environmental remediation liability when site assessments indicate that remediation is probable and the Utility can reasonably estimate the loss or a range of probable amounts. The Utility records an environmental remediation liability based on the lower end of the range of estimated probable costs,

NOTE 15: COMMITMENTS AND CONTINGENCIES (Continued)

unless an amount within the range is a better estimate than any other amount. Amounts recorded are not discounted to their present value.

The following table presents the changes in the environmental remediation liability:

(in millions)	
Balance at December 31, 2011	$ 785
Additional remediation costs accrued:	
Transfer to regulatory account for recovery	150
Amounts not recoverable from customers	150
Less: Payments	(175)
Balance at December 31, 2012	**$ 910**

The environmental remediation liability is composed of the following:

	Balance at December 31,	
(in millions)	2012	2011
Utility-owned natural gas compressor site near Hinkley, California[1]	$ 226	$ 149
Utility-owned natural gas compressor site near Topock, Arizona[1]	239	218
Utility-owned generation facilities (other than for fossil fuel-fired), other facilities, and third-party disposal sites	158	133
Former manufatured gas plant sites owned by the Utility or third parties	181	154
Fossil fuel-fired generation facilities formerly owned by the Utility	87	81
Decommissioning fossil fuel-fired generation facilities and sites	19	50
Total environmental remediation liability	**$ 910**	**$ 785**

(1) See "Natural Gas Compressor Site" below.

The CPUC has authorized the Utility to recover most of its environmental remediation costs through various ratemaking mechanisms, subject to exclusions for certain sites, such as the Hinkley natural gas compressor site, and subject to limitations for certain liabilities such as amounts associated with fossil fuel-fired generation facilities formerly owned by the Utility. At December 31, 2012, the Utility expected to recover $548 million through these ratemaking mechanisms. The Utility also recovers environmental remediation costs from insurance carriers and from other third parties whenever possible. Amounts collected in excess of the Utility's ultimate obligations may be subject to refund to customers through rates.

Natural Gas Compressor Sites

The Utility is legally responsible for remediating groundwater contamination caused by hexavalent chromium used in the past at the Utility's natural gas compressor sites near Hinkley, California ("Hinkley site") and Topock, Arizona ("Topock site"). The Utility is also required to take measures to abate the effects of the contamination on the environment.

Hinkley Site

The Utility's remediation and abatement efforts at the Hinkley site are subject to the regulatory authority of the California Regional Water Quality Control Board, Lahontan Region ("Regional Board"). The Regional Board has issued several orders directing the Utility to implement interim remedial measures to reduce the mass of the underground plume of hexavalent chromium, monitor and control movement of the plume, and provide replacement water to affected residents.

NOTE 15: COMMITMENTS AND CONTINGENCIES (Continued)

The Utility submitted its proposed final remediation plan to the Regional Board in September 2011 recommending a combination of remedial methods to clean up groundwater contamination, including using pumped groundwater from extraction wells to irrigate agricultural land and in-situ treatment of the contaminated water. In August 2012, the Regional Board issued a draft environmental impact report ("EIR") that evaluated the Utility's proposed methods and the potential environmental impacts. The Utility expects that the Regional Board will consider certification of the final EIR in the second quarter of 2013. Upon certification of the EIR, the Regional Board is expected to issue the final cleanup standards in late 2013.

The Regional Board ordered the Utility in October 2011 to provide an interim and permanent replacement water system for resident households located near the chromium plume that have domestic wells containing hexavalent chromium in concentrations greater than 0.02 parts per billion. The Utility filed a petition with the California State Water Resources Control Board to contest certain provisions of the order. In June 2012, the Regional Board issued an amended order to allow the Utility to implement a whole house water replacement program for resident households located near the chromium plume boundary. Eligible residents may decide whether to accept a replacement water supply or have the Utility purchase their properties, or alternatively not participate in the program. As of January 31, 2013, approximately 350 residential households are covered by the program and the majority have opted to accept the Utility's offer to purchase their properties. The Utility is required to complete implementation of the whole house water replacement systems by August 31, 2013. The Utility will maintain and operate the whole house replacement systems for five years or until the State of California has adopted a drinking water standard specifically for hexavalent chromium at which time the program will be evaluated.

At December 31, 2012 and 2011, $226 million and $149 million, respectively, were accrued in PG&E Corporation's and the Utility's Consolidated Balance Sheets for estimated undiscounted future remediation costs associated with the Hinkley site. The increase primarily reflects the Utility's best estimate of costs associated with the developments described above. Remediation costs for the Hinkley natural gas compressor site are not recovered from customers through rates. Future costs will depend on many factors, including the Regional Board's certification of the final EIR, the levels of hexavalent chromium the Utility is required to use as the standard for remediation, the Utility's required time frame for remediation, and adoption of a final drinking water standard currently under development by the State of California, as mentioned above. As more information becomes known regarding these factors, these estimates and the assumptions on which they are based regarding the amount of liability incurred may be subject to further changes. Future changes in estimates or assumptions may have a material impact on PG&E Corporation's and the Utility's future financial condition, results of operations, and cash flows.

Topock Site

The Utility's remediation and abatement efforts are subject to the regulatory authority of the Department of Toxic Substances Control ("DTSC") and the U.S. Department of the Interior ("DOI"). As directed by the DTSC, the Utility has implemented interim remediation measures, including a system of extraction wells and a treatment plant designed to prevent movement of a hexavalent chromium plume toward the Colorado River. The DTSC has certified the final EIR and approved the Utility's final remediation plan for the groundwater plume, under which the Utility will implement an in-situ groundwater treatment system to convert hexavalent chromium into a non-toxic and non-soluble form of chromium. The Utility has completed the preliminary design stage for implementing the final groundwater remedy and is required to submit its intermediate design plan to the DTSC and DOI by April 5, 2013 and a final plan for approval in 2014. In developing its intermediate plan, the Utility is currently evaluating input received from regulatory agencies and other stakeholders, exploring potential sources of fresh water to be used as part of the remedy, and performing other engineering activities necessary to complete the remedial design.

At December 31, 2012 and 2011, $239 million and $218 million, respectively, were accrued in PG&E Corporation's and the Utility's Consolidated Balance Sheets for estimated undiscounted future remediation costs associated with the Topock site. The CPUC has authorized the Utility to recover 90% of its remediation costs for the Topock site from customers through rates without a reasonableness review. As the Utility completes its remedial design plan and more information becomes known regarding the extent of work to be performed to implement the final groundwater remedy, these estimates and the assumptions on which they are based regarding the amount of

NOTE 15: COMMITMENTS AND CONTINGENCIES (Continued)

liability incurred may be subject to change. Future changes in estimates or assumptions could have a material impact on PG&E Corporation's and the Utility's future financial condition.

Reasonably Possible Environmental Contingencies

Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, the Utility's undiscounted future costs could increase to as much as $1.6 billion (including amounts related to the Hinkley and Topock sites described above) if the extent of contamination or necessary remediation is greater than anticipated or if the other potentially responsible parties are not financially able to contribute to these costs, and could increase further if the Utility chooses to remediate beyond regulatory requirements. The Utility may incur actual costs in the future that are materially different than this estimate and such costs could have a material impact on PG&E Corporation's and the Utility's results of operations during the period in which they are recorded.

QUARTERLY CONSOLIDATED FINANCIAL DATA (UNAUDITED)

(in millions, except per share amounts)	Quarter ended December 31	September 30	June 30	March 31
2012				
PG&E CORPORATION				
Operating revenues	$ 3,830	$ 3,976	$ 3,593	$ 3,641
Operating income	125	614	467	487
Net income (loss)	(9)	364	239	236
Income (loss) available for common shareholders	(13)	361	235	233
Net earnings (loss) per common share, basic	(0.03)	0.84	0.56	0.56
Net earnings (loss) per common share, diluted	(0.03)	0.84	0.55	0.56
Common stock price per share:				
High	43.48	46.51	45.20	43.72
Low	39.71	42.41	42.04	40.16
UTILITY				
Operating revenues	$ 3,829	$ 3,974	$ 3,592	$ 3,640
Operating income	127	613	467	488
Net income	13	340	227	231
Income available for common stock	9	337	223	228
2011				
PG&E CORPORATION				
Operating revenues	$ 3,815	$ 3,860	$ 3,684	$ 3,597
Operating income	358	408	692	484
Net income	87	203	366	202
Income available for common shareholders	83	200	362	199
Net earnings per common share, basic	0.20	0.50	0.91	0.50
Net earnings per common share, diluted	0.20	0.50	0.91	0.50
Common stock price per share:				
High	43.24	43.32	46.52	47.60
Low	36.86	39.21	41.39	42.47
UTILITY				
Operating revenues	$ 3,813	$ 3,859	$ 3,683	$ 3,596
Operating income	359	402	699	484
Net income	89	196	359	201
Income available for common stock	85	193	355	198

During the fourth quarter 2012, the Utility recorded a charge to net income of $353 million for disallowed capital expenditures associated with the Utility's pipeline safety enhancement plan. See Note 15 of the Notes to the Consolidated Financial Statements.

During the second quarter 2012 the Utility recorded a provision of $80 million for estimated third-party claims related to the San Bruno accident. During the first quarter 2012, second quarter of 2012, third quarter of 2012, and fourth quarter 2012, the Utility submitted insurance claims to certain insurers for the lower layers and recognized $11 million, $25 million, $99 million, and $50 million, respectively, for insurance recoveries. See Note 15 of the Notes to the Consolidated Financial Statements.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of PG&E Corporation and Pacific Gas and Electric Company ("Utility") is responsible for establishing and maintaining adequate internal control over financial reporting. PG&E Corporation's and the Utility's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, or GAAP. Internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of PG&E Corporation and the Utility, (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP and that receipts and expenditures are being made only in accordance with authorizations of management and directors of PG&E Corporation and the Utility, and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of internal control over financial reporting as of December 31, 2012, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its assessment and those criteria, management has concluded that PG&E Corporation and the Utility maintained effective internal control over financial reporting as of December 31, 2012.

Deloitte & Touche LLP, an independent registered public accounting firm, has audited PG&E Corporation's and the Utility's internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

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 accompanying consolidated balance sheets of PG&E Corporation and subsidiaries (the "Company") and of Pacific Gas and Electric Company and subsidiaries (the "Utility") as of December 31, 2012 and 2011, and the Company's related consolidated statements of income, comprehensive income, equity, and cash flows and the Utility's related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company's and the Utility's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of PG&E Corporation and subsidiaries and of Pacific Gas and Electric Company and subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 15 to the consolidated financial statements, several investigations and enforcement matters are pending with the California Public Utilities Commission and may result in material amounts of penalties.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's and the Utility's internal control over financial reporting as of December 31, 2012, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 21, 2013 expressed an unqualified opinion on the Company's and the Utility's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California
February 21, 2013

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 internal control over financial reporting of PG&E Corporation and subsidiaries (the "Company") and of Pacific Gas and Electric Company and subsidiaries (the "Utility") as of December 31, 2012, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's and the Utility's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting.* Our responsibility is to express an opinion on the Company's and the Utility's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audits included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company and the Utility maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2012 of the Company and the Utility and our report dated February 21, 2013 expressed an unqualified opinion on those financial statements and includes an explanatory paragraph relating to several investigations and enforcement matters pending with the California Public Utilities Commission that may result in material amounts of penalties.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California
February 21, 2013

BOARDS OF DIRECTORS OF PG&E CORPORATION AND PACIFIC GAS AND ELECTRIC COMPANY

DAVID R. ANDREWS
Senior Vice President, Government Affairs, General Counsel and Secretary, Retired, PepsiCo, Inc.

LEWIS CHEW
Executive Vice President and Chief Financial Officer, Dolby Laboratories, Inc.

C. LEE COX(1)
Vice Chairman, Retired, AirTouch Communications, Inc. and President and Chief Executive Officer, Retired, AirTouch Cellular

ANTHONY F. EARLEY, JR.
Chairman of the Board, Chief Executive Officer, and President, PG&E Corporation

FRED J. FOWLER
Chairman of the Board, Spectra Energy Partners, LP

MARYELLEN C. HERRINGER
Executive Vice President, General Counsel, and Secretary, Retired, APL Limited

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President, Pacific Gas and Electric Company

ROGER H. KIMMEL
Vice Chairman, Rothschild Inc.

RICHARD A. MESERVE
President, Carnegie Institution of Washington

FORREST E. MILLER
Group President-Corporate Strategy and Development, Retired, AT&T Inc.

ROSENDO G. PARRA
Senior Vice President, Retired, Dell Inc. and Partner and Co-Founder, Daylight Partners

BARBARA L. RAMBO
Chief Executive Officer, Taconic Management Services

BARRY LAWSON WILLIAMS
Managing General Partner, Retired, and President, Williams Pacific Ventures, Inc.

(1) C. Lee Cox is the non-executive Chairman of the Board of Pacific Gas and Electric Company, as well as the lead director of PG&E Corporation and Pacific Gas and Electric Company.

(2) Christopher P. Johns is a director of Pacific Gas and Electric Company only.

PG&E CORPORATION OFFICERS

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Chairman of the Board, Chief Executive Officer, and President

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Senior Vice President and Chief Financial Officer

HYUN PARK
Senior Vice President and General Counsel

GREG S. PRUETT
Senior Vice President, Corporate Affairs

JOHN R. SIMON
Senior Vice President, Human Resources

NICHOLAS M. BIJUR
Vice President and Treasurer

STEPHEN J. CAIRNS
Vice President, Internal Audit and Compliance

MARK T. CARON
Vice President, Tax

LINDA Y.H. CHENG
Vice President, Corporate Governance and Corporate Secretary

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Vice President, Federal Affairs

DINYAR B. MISTRY
Vice President and Controller

ANIL K. SURI
Vice President and Chief Risk and Audit Officer

GABRIEL B. TOGNERI
Vice President, Investor Relations

PACIFIC GAS AND ELECTRIC COMPANY OFFICERS

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Non-executive Chairman of the Board

CHRISTOPHER P. JOHNS
President

NICKOLAS STAVROPOULOS
Executive Vice President, Gas Operations

GEISHA J. WILLIAMS
Executive Vice President, Electric Operations

KAREN A. AUSTIN
Senior Vice President and Chief Information Officer

DESMOND A. BELL
Senior Vice President, Safety and Shared Services

THOMAS E. BOTTORFF
Senior Vice President, Regulatory Affairs

HELEN A. BURT
Senior Vice President and Chief Customer Officer

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Senior Vice President, Energy Supply

EDWARD D. HALPIN
Senior Vice President and Chief Nuclear Officer

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GREGORY K. KIRALY
Senior Vice President, Electric Distribution Operations

GREG S. PRUETT
Senior Vice President, Corporate Affairs

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Senior Vice President, Gas Transmission Operations

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Senior Vice President, Energy Procurement

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Vice President, Corporate Strategy

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Site Vice President, Diablo Canyon Power Plant

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Vice President, Strategic Business Management

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Vice President, Government Relations

VALERIE J. BELL
Vice President, Information Technology Operations

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Vice President and Treasurer

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Vice President, Talent Management and Chief Diversity Officer

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Vice President, Internal Audit and Compliance

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Vice President, Tax

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Vice President, Corporate Governance and Corporate Secretary

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Vice President, Regulation and Rates

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Vice President, Community Relations and Chief Sustainability Officer

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Vice President and Managing Director, Law

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Vice President, Customer Energy Solutions

PLACIDO J. MARTINEZ
Vice President, Strategic Asset Management

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JASON P. WELLS
Vice President, Finance

ANDREW K. WILLIAMS
Vice President, Human Resources

JANE K. YURA
Vice President, Gas Standards and Policy

SHAREHOLDER INFORMATION

For financial and other information about PG&E Corporation and Pacific Gas and Electric Company, please visit our websites, www.pgecorp.com and www.pge.com, respectively.

As of February 11, 2013, there were 67,982 holders of record of PG&E Corporation common stock. PG&E Corporation is the holder of all issued and outstanding shares of Pacific Gas and Electric Company common stock.

If you have questions about your PG&E Corporation common stock account or Pacific Gas and Electric Company preferred stock account, please contact our transfer agent, American Stock Transfer and Trust Company, LLC ("AST").

American Stock Transfer and Trust Company, LLC
6201 15th Avenue
Brooklyn, NY 11219

Toll-free telephone services: 1-888-489-4689 (Customer Service Representatives are available Monday through Friday from 8:00 a.m. ET to 8:00 p.m. ET)

Website: http://www.amstock.com

If you have general questions about PG&E Corporation or Pacific Gas and Electric Company, please contact the Corporate Secretary's Office.

Vice President, Corporate Governance and Corporate Secretary
Linda Y.H. Cheng
PG&E Corporation
Pacific Gas and Electric Company
P. O. Box 770000
San Francisco, CA 94177
415-973-8200
Fax 415-973-8719

Securities analysts, portfolio managers, or other representatives of the investment community should contact the Investor Relations Office.

Vice President, Investor Relations
Gabriel B. Togneri
PG&E Corporation
P. O. Box 770000
San Francisco, CA 94177
415-972-7080

PG&E Corporation
General Information
415-973-1000

Pacific Gas and Electric Company
General Information
415-973-7000

Stock Held in Brokerage Accounts ("Street Name")
When you purchase your stock and it is held for you by your broker, the shares are listed with AST in the broker's name, or street name. AST does not know the identity of the individual shareholders who hold their shares in this manner. They simply know that a broker holds a number of shares that may be held for any number of investors. If you hold your stock in a street name account, you receive all tax forms, publications, and proxy materials through your broker. If you are receiving unwanted duplicate mailings, you should contact your broker to eliminate the duplications.

Stock Exchange Listings
PG&E Corporation's common stock is traded on the New York and Swiss stock exchanges. The official New York Stock Exchange symbol is "PCG," but PG&E Corporation common stock is listed in daily newspapers under "PG&E" or "PG&E Cp."(1)

Pacific Gas and Electric Company has eight issues of preferred stock, all of which are listed on NYSE MKT (formerly known as NYSE Amex).

Issue	Newspaper Symbol(1)
First Preferred Cumulative, Par Value $25 Per Share	
Non Redeemable:	
6.00%	PacGE pfA
5.50%	PacGE pfB
5.00%	PacGE pfC
Redeemable:	
5.00%	PacGE pfD
5.00% Series A	PacGE pfE
4.80%	PacGE pfG
4.50%	PacGE pfH
4.36%	PacGE pfI

(1) Local newspaper symbols may vary.

2013 Dividend Payment Dates

PG&E Corporation
January 15
April 15
July 15
October 15

Pacific Gas and Electric Company
February 15
May 15
August 15
November 15

PG&E Corporation Dividend Reinvestment and Stock Purchase Plan ("DRSPP")
If you hold PG&E Corporation or Pacific Gas and Electric Company stock in your own name, rather than through a broker, you may automatically reinvest dividend payments from common and/or preferred stock in shares of PG&E Corporation common stock through the DRSPP. You may obtain a DRSPP prospectus and enroll by contacting AST. If your shares are held by a broker in street name, you are not eligible to participate in the DRSPP.

Replacement of Dividend Checks
If you hold stock in your own name and you do not receive your dividend check within 10 days after the payment date, or if a check is lost or destroyed, you should notify AST so that payment can be stopped on the check and a replacement can be mailed.

Lost or Stolen Stock Certificates
If you hold stock in your own name and your stock certificate has been lost, stolen, or in some way destroyed, you should notify AST immediately.

PG&E CORPORATION AND PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL MEETINGS OF SHAREHOLDERS

Date: May 6, 2013

Time: 10:00 a.m.

Location: PG&E Corporation and
Pacific Gas and Electric Company Headquarters
77 Beale Street
San Francisco, CA 94105

Form 10-K

If you would like to obtain a copy, free of charge, of PG&E Corporation's and Pacific Gas and Electric Company's joint Annual Report on Form 10-K for the year ended December 31, 2012, which has been filed with the Securities and Exchange Commission, please send a written request to, or call, the Corporate Secretary's Office at:

Linda Y.H. Cheng
PG&E Corporation
Pacific Gas and Electric Company
P. O. Box 770000
San Francisco, CA 94177
415-973-8200
Fax 415-973-8719

You may also view the Form 10-K, and all other reports submitted by PG&E Corporation and Pacific Gas and Electric Company to the Securities and Exchange Commission, on our website at:

www.pgecorp.com/investors/financial_reports/

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