PACIFIC GAS & ELECTRIC Co
Form 10-Q
October 29, 2012

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C., 20549
FORM 10-Q

(Mark One)

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2012

OR

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

For the transition period from ___________ to __________

Commission File Number	Exact Name of Registrant as Specified in its Charter	State or Other Jurisdiction of Incorporation	IRS Employer Identification Number
1-12609	PG&E Corporation	California	94-3234914
1-2348	Pacific Gas and Electric Company	California	94-0742640

Pacific Gas and Electric Company 77 Beale Street P.O. Box 770000 San Francisco, California 94177	PG&E Corporation 77 Beale Street P.O. Box 770000 San Francisco, California 94177

Address of principal executive offices, including zip code

Pacific Gas and Electric Company (415) 973-7000	PG&E Corporation (415) 267-7000

Registrant's telephone number, including area code

Indicate by check mark whether each registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. [X] Yes [ ] No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

PG&E Corporation:	[X] Yes [ ] No
Pacific Gas and Electric Company:	[X] Yes [ ] No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of “large accelerated filer”, “accelerated filer”, and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

PG&E Corporation:	[X] Large accelerated filer	[ ] Accelerated filer
	[ ] Non-accelerated filer	[ ] Smaller reporting company
Pacific Gas and Electric Company:	[ ] Large accelerated filer	[ ] Accelerated filer
	[X] Non-accelerated filer	[ ] Smaller reporting company

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

PG&E Corporation:	[ ] Yes [X] No
Pacific Gas and Electric Company:	[ ] Yes [X] No

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Common stock outstanding as of October 25, 2012:

PG&E Corporation:	429,984,324
Pacific Gas and Electric Company:	264,374,809

PG&E CORPORATION AND
PACIFIC GAS AND ELECTRIC COMPANY
FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2012
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PG&E CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	(Unaudited)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions, except per share amounts)	2012	2011	2012	2011
Operating Revenues				
Electric	$3,323	$3,188	$9,026	$8,694
Natural gas	653	672	2,184	2,447
Total operating revenues	3,976	3,860	11,210	11,141
Operating Expenses				
Cost of electricity	1,283	1,224	3,104	3,018
Cost of natural gas	118	170	593	936
Operating and maintenance	1,344	1,492	4,138	3,955
Depreciation, amortization, and decommissioning	617	566	1,807	1,648
Total operating expenses	3,362	3,452	9,642	9,557
Operating Income	614	408	1,568	1,584
Interest income	2	2	6	7
Interest expense	(178)	(176)	(528)	(527)
Other income, net	26	18	84	56
Income Before Income Taxes	464	252	1,130	1,120
Income tax provision	100	49	291	349
Net Income	364	203	839	771
Preferred stock dividend requirement of subsidiary	3	3	10	10
Income Available for Common Shareholders	$361	$200	$829	$761
Weighted Average Common Shares Outstanding, Basic	428	403	422	399
Weighted Average Common Shares Outstanding, Diluted	429	404	423	400
Net Earnings Per Common Share, Basic	$0.84	$0.50	$1.96	$1.91
Net Earnings Per Common Share, Diluted	$0.84	$0.50	$1.96	$1.90
Dividends Declared Per Common Share	$0.46	$0.46	$1.37	$1.37

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	(Unaudited)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2012	2011	2012	2011
Net Income	$364	$203	$839	$771
Other Comprehensive Income				
Pension and other postretirement benefit plans				
Unrecognized prior service credit (net of income tax of $5 and $7 in the three months ended September 30, 2012 and 2011, respectively, and $15 and $18 in the nine months ended September 30, 2012 and 2011, respectively)	7	9	19	28
Unrecognized net gain (net of income tax of $12 and $6 in the three months ended September 30, 2012 and 2011, respectively, and $38 and $17 in the nine months ended September 30, 2012 and 2011, respectively)	18	8	58	23
Unrecognized net transition obligation (net of income tax of $2 and $3 in the three months ended September 30, 2012 and 2011, respectively, and $6 and $7 in the nine months ended September 30, 2012 and 2011, respectively)	4	4	12	12
Transfer to regulatory account (net of income tax of $14 and $8 in the three months ended September 30, 2012 and 2011, respectively, and $44 and $26 in the nine months ended September 30, 2012 and 2011, respectively)	(21)	(13)	(63)	(37)
Total other comprehensive income	8	8	26	26
Comprehensive Income	372	211	865	797
Preferred stock dividend requirement of subsidiary	3	3	10	10
Comprehensive Income Attributable to Common Shareholders	$369	$208	$855	$787

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions)	(Unaudited) Balance at September 30, 2012	December 31, 2011
ASSETS		
Current Assets		
Cash and cash equivalents	$296	$513
Restricted cash ($88 and $51 related to energy recovery bonds at September 30, 2012 and December 31, 2011, respectively)	418	380
Accounts receivable		
Customers (net of allowance for doubtful accounts of $85 and $81 at September 30, 2012 and December 31, 2011, respectively)	1,185	992
Accrued unbilled revenue	779	763
Regulatory balancing accounts	908	1,082
Other	665	839
Regulatory assets ($0 and $336 related to energy recovery bonds at September 30, 2012 and December 31, 2011, respectively)	567	1,090
Inventories		
Gas stored underground and fuel oil	158	159
Materials and supplies	296	261
Income taxes receivable	19	183
Other	302	218
Total current assets	5,593	6,480
Property, Plant, and Equipment		
Electric	37,635	35,851
Gas	12,280	11,931
Construction work in progress	2,095	1,770
Other	1	15
Total property, plant, and equipment	52,011	49,567
Accumulated depreciation	(16,361)	(15,912)
Net property, plant, and equipment	35,650	33,655
Other Noncurrent Assets		
Regulatory assets	6,527	6,506
Nuclear decommissioning trusts	2,155	2,041
Income taxes receivable	333	386
Other	610	682
Total other noncurrent assets	9,625	9,615
TOTAL ASSETS	$50,868	$49,750

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited) Balance at	
(in millions)	September 30, 2012	December 31, 2011
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term borrowings	$397	$1,647
Long-term debt, classified as current	-	50
Energy recovery bonds, classified as current	110	423
Accounts payable		
Trade creditors	1,054	1,177
Disputed claims and customer refunds	164	673
Regulatory balancing accounts	459	374
Other	423	420
Interest payable	821	843
Income taxes payable	15	110
Deferred income taxes	-	196
Other	1,993	1,836
Total current liabilities	5,436	7,749
Noncurrent Liabilities		
Long-term debt	12,915	11,766
Regulatory liabilities	5,107	4,733
Pension and other postretirement benefits	3,570	3,396
Asset retirement obligations	1,661	1,609
Deferred income taxes	6,724	6,008
Other	2,070	2,136
Total noncurrent liabilities	32,047	29,648
Commitments and Contingencies (Note 10)		
Equity		
Shareholders' Equity		
Preferred stock	-	-
Common stock, no par value, authorized 800,000,000 shares, 429,357,175 shares outstanding at September 30, 2012 and 412,257,082 shares outstanding at December 31, 2011	8,362	7,602
Reinvested earnings	4,957	4,712
Accumulated other comprehensive loss	(186)	(213)
Total shareholders' equity	13,133	12,101
Noncontrolling Interest – Preferred Stock of Subsidiary	252	252
Total equity	13,385	12,353
TOTAL LIABILITIES AND EQUITY	$50,868	$49,750

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)	(Unaudited) Nine Months Ended September 30, 2012	2011
Cash Flows from Operating Activities		
Net income	$839	$771
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	1,807	1,648
Allowance for equity funds used during construction	(79)	(64)
Deferred income taxes and tax credits, net	624	552
Other	230	223
Effect of changes in operating assets and liabilities:		
Accounts receivable	(326)	(186)
Inventories	(34)	(60)
Accounts payable	(55)	93
Income taxes receivable/payable	69	(71)
Other current assets and liabilities	16	(170)
Regulatory assets, liabilities, and balancing accounts, net	66	70
Other noncurrent assets and liabilities	295	426
Net cash provided by operating activities	3,452	3,232
Cash Flows from Investing Activities		
Capital expenditures	(3,361)	(2,968)
(Increase) decrease in restricted cash	(38)	170
Proceeds from sales and maturities of nuclear decommissioning trust investments	903	1,574
Purchases of nuclear decommissioning trust investments	(964)	(1,604)
Other	101	(102)
Net cash used in investing activities	(3,359)	(2,930)
Cash Flows from Financing Activities		
Borrowings under revolving credit facilities	-	358
Repayments under revolving credit facilities	-	(283)
Net (repayments) issuances of commercial paper, net of discount of $3 in 2012 and $2 in 2011	(1,247)	196
Proceeds from issuance of long-term debt, net of discount and issuance costs of $10 in 2012 and $6 in 2011	1,140	544
Long-term debt matured or repurchased	(50)	(700)
Energy recovery bonds matured	(313)	(299)
Common stock issued, net of issuance costs of $3 in 2012 and $2 in 2011	702	391
Common stock dividends paid	(556)	(525)
Other	14	2
Net cash used in financing activities	(310)	(316)
Net change in cash and cash equivalents	(217)	(14)
Cash and cash equivalents at January 1	513	291
Cash and cash equivalents at September 30	$296	$277
Supplemental disclosures of cash flow information		
Cash received (paid) for:		
Interest, net of amounts capitalized	$(486)	$(536)

Income taxes, net	114	8
Supplemental disclosures of noncash investing and financing activities		
Common stock dividends declared but not yet paid	$195	$184
Capital expenditures financed through accounts payable	228	225
Noncash common stock issuances	18	18
Terminated capital leases	136	-

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	(Unaudited)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2012	2011	2012	2011
Operating Revenues				
Electric	$3,321	$3,187	$9,022	$8,691
Natural gas	653	672	2,184	2,447
Total operating revenues	3,974	3,859	11,206	11,138
Operating Expenses				
Cost of electricity	1,283	1,224	3,104	3,018
Cost of natural gas	118	170	593	936
Operating and maintenance	1,343	1,497	4,134	3,951
Depreciation, amortization, and decommissioning	617	566	1,807	1,648
Total operating expenses	3,361	3,457	9,638	9,553
Operating Income	613	402	1,568	1,585
Interest income	2	2	5	6
Interest expense	(172)	(171)	(511)	(511)
Other income, net	19	19	64	52
Income Before Income Taxes	462	252	1,126	1,132
Income tax provision	122	56	328	376
Net Income	340	196	798	756
Preferred stock dividend requirement	3	3	10	10
Income Available for Common Stock	$337	$193	$788	$746

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	(Unaudited)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2012	2011	2012	2011
Net Income	$340	$196	$798	$756
Other Comprehensive Income				
Pension and other postretirement benefit plans				
Unrecognized prior service credit (net of income tax of $5 and $7 in the three months ended September 30, 2012 and 2011, respectively, and $15 and $18 in the nine months ended September 30, 2012 and 2011, respectively)	7	9	19	28
Unrecognized net gain (net of income tax of $12 and $6 in the three months ended September 30, 2012 and 2011, respectively, and $38 and $17 in the nine months ended September 30, 2012, and 2011, respectively)	18	8	58	23
Unrecognized net transition obligation (net of income tax of $2 and $3 in the three months ended September 30, 2012 and 2011, respectively, and $6 and $7 in the nine months ended September 30, 2012 and 2011, respectively)	4	4	12	12
Transfer to regulatory account (net of income tax of $14 and $8 in the three months ended September 30, 2012 and 2011, respectively, and $44 and $26 in the nine months ended September 30, 2012 and 2011, respectively)	(21)	(13)	(63)	(37)
Total other comprehensive income	8	8	26	26
Comprehensive Income	$348	$204	$824	$782

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited) Balance at	
(in millions)	September 30, 2012	December 31, 2011
ASSETS		
Current Assets		
Cash and cash equivalents	$86	$304
Restricted cash ($88 and $51 related to energy recovery bonds at September 30, 2012 and December 31, 2011, respectively)	418	380
Accounts receivable		
Customers (net of allowance for doubtful accounts of $85 and $81 at September 30, 2012 and December 31, 2011, respectively)	1,185	992
Accrued unbilled revenue	779	763
Regulatory balancing accounts	908	1,082
Other	667	840
Regulatory assets ($0 and $336 related to energy recovery bonds at September 30, 2012 and December 31, 2011, respectively)	567	1,090
Inventories		
Gas stored underground and fuel oil	158	159
Materials and supplies	296	261
Income taxes receivable	-	242
Other	295	213
Total current assets	5,359	6,326
Property, Plant, and Equipment		
Electric	37,635	35,851
Gas	12,280	11,931
Construction work in progress	2,095	1,770
Total property, plant, and equipment	52,010	49,552
Accumulated depreciation	(16,360)	(15,898)
Net property, plant, and equipment	35,650	33,654
Other Noncurrent Assets		
Regulatory assets	6,527	6,506
Nuclear decommissioning trusts	2,155	2,041
Income taxes receivable	331	384
Other	324	331
Total other noncurrent assets	9,337	9,262
TOTAL ASSETS	$50,346	$49,242

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited) Balance At	
(in millions, except share amounts)	September 30, 2012	December 31, 2011
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$397	$1,647
Long-term debt, classified as current	-	50
Energy recovery bonds, classified as current	110	423
Accounts payable		
Trade creditors	1,054	1,177
Disputed claims and customer refunds	164	673
Regulatory balancing accounts	459	374
Other	444	417
Interest payable	811	838
Income taxes payable	29	118
Deferred income taxes	-	199
Other	1,777	1,628
Total current liabilities	5,245	7,544
Noncurrent Liabilities		
Long-term debt	12,566	11,417
Regulatory liabilities	5,107	4,733
Pension and other postretirement benefits	3,496	3,325
Asset retirement obligations	1,661	1,609
Deferred income taxes	6,888	6,160
Other	2,006	2,070
Total noncurrent liabilities	31,724	29,314
Commitments and Contingencies (Note 10)		
Shareholders' Equity		
Preferred stock	258	258
Common stock, $5 par value, authorized 800,000,000 shares, 264,374,809 shares outstanding at September 30, 2012 and December 31, 2011	1,322	1,322
Additional paid-in capital	4,511	3,796
Reinvested earnings	7,461	7,210
Accumulated other comprehensive loss	(175)	(202)
Total shareholders' equity	13,377	12,384
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$50,346	$49,242

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	(Unaudited) Nine Months Ended September 30,	
(in millions)	2012	2011
Cash Flows from Operating Activities		
Net income	$798	$756
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	1,807	1,648
Allowance for equity funds used during construction	(79)	(64)
Deferred income taxes and tax credits, net	633	564
Other	189	193
Effect of changes in operating assets and liabilities:		
Accounts receivable	(327)	(125)
Inventories	(34)	(60)
Accounts payable	(31)	97
Income taxes receivable/payable	153	(156)
Other current assets and liabilities	15	(153)
Regulatory assets, liabilities, and balancing accounts, net	66	70
Other noncurrent assets and liabilities	315	491
Net cash provided by operating activities	3,505	3,261
Cash Flows from Investing Activities		
Capital expenditures	(3,361)	(2,968)
(Increase) decrease in restricted cash	(38)	170
Proceeds from sales and maturities of nuclear decommissioning trust investments	903	1,574
Purchases of nuclear decommissioning trust investments	(964)	(1,604)
Other	14	13
Net cash used in investing activities	(3,446)	(2,815)
Cash Flows from Financing Activities		
Borrowings under revolving credit facilities	-	208
Repayments under revolving credit facilities	-	(208)
Net (repayments) issuances of commercial paper, net of discount of $3 in 2012 and $2 in 2011	(1,247)	196
Proceeds from issuance of long-term debt, net of discount and issuance costs of $10 in 2012 and $6 in 2011	1,140	544
Long-term debt matured or repurchased	(50)	(700)
Energy recovery bonds matured	(313)	(299)
Preferred stock dividends paid	(10)	(10)
Common stock dividends paid	(537)	(537)
Equity contribution	715	350
Other	25	12
Net cash used in financing activities	(277)	(444)
Net change in cash and cash equivalents	(218)	2
Cash and cash equivalents at January 1	304	51
Cash and cash equivalents at September 30	$86	$53
Supplemental disclosures of cash flow information		
Cash received (paid) for:		

Interest, net of amounts capitalized	$(476)	$(525)
Income taxes, net	174	6
Supplemental disclosures of noncash investing and financing activities		
Capital expenditures financed through accounts payable	$228	$225
Terminated capital leases	136	-

See accompanying Notes to the Condensed Consolidated Financial Statements.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

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 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 quarterly report on Form 10-Q is a combined report of PG&E Corporation and the Utility that includes separate Condensed Consolidated Financial Statements for each company. The Notes to the Condensed Consolidated Financial Statements apply to both PG&E Corporation and the Utility. PG&E Corporation's Condensed Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries. The Utility's Condensed Consolidated Financial Statements include the accounts of the Utility and its wholly owned and controlled subsidiaries. All intercompany transactions have been eliminated from the Condensed Consolidated Financial Statements.

The accompanying Condensed Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") for interim financial statements and in accordance with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X promulgated by the Securities and Exchange Commission ("SEC") and therefore do not contain all of the information and footnotes required by GAAP and the SEC for annual financial statements. PG&E Corporation's and the Utility's Condensed Consolidated Financial Statements reflect all adjustments (consisting only of normal recurring adjustments) that management believes are necessary for the fair presentation of their financial condition, results of operations, and cash flows for the periods presented. The information at December 31, 2011 in both PG&E Corporation's and the Utility's Condensed Consolidated Balance Sheets included in this quarterly report was derived from the audited Consolidated Balance Sheets incorporated by reference into their combined 2011 Annual Report on Form 10-K filed with the SEC on February 16, 2012. PG&E Corporation's and the Utility's combined 2011 Annual Report on Form 10-K, together with the information incorporated by reference into such report, is referred to in this quarterly report as the "2011 Annual Report." This quarterly report should be read in conjunction with the 2011 Annual Report.

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 Condensed Consolidated Financial Statements are appropriate and reasonable. Actual results could differ materially from those estimates.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES

The significant accounting policies used by PG&E Corporation and the Utility are discussed in Note 2 of the Notes to the Consolidated Financial Statements in the 2011 Annual Report.

Pension and Other Postretirement Benefits

PG&E Corporation and the Utility provide a non-contributory defined benefit pension plan for eligible employees and retirees (referred to collectively as "pension benefits") and contributory postretirement medical plans for eligible employees and retirees and their eligible dependents and non-contributory postretirement life insurance plans for eligible employees and retirees (referred to collectively as "other benefits"). PG&E Corporation and the Utility have elected that certain of the trusts underlying these plans be treated under the Internal Revenue Code of 1986, as amended ("Code"), as qualified trusts. 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.

The net periodic benefit costs reflected in PG&E Corporation's Condensed Consolidated Financial Statements for the three and nine months ended September 30, 2012 and 2011 were as follows:

	Pension Benefits Three Months Ended September 30,		Other Benefits Three Months Ended September 30,	
(in millions)	2012	2011	2012	2011
Service cost for benefits earned	$100	$76	$14	$9
Interest cost	165	167	21	23
Expected return on plan assets	(150)	(168)	(19)	(22)
Amortization of transition obligation	-	-	6	7
Amortization of prior service cost	5	8	7	8
Amortization of unrecognized loss	29	13	1	1
Net periodic benefit cost	149	96	30	26
Less: transfer to regulatory account (1)	(75)	(32)	-	-
Total	$74	$64	$30	$26

(1) The Utility recorded these amounts to a regulatory account since they are probable of recovery from customers in future rates.

	Pension Benefits Nine Months Ended September 30,		Other Benefits Nine Months Ended September 30,	
(in millions)	2012	2011	2012	2011
Service cost for benefits earned	$297	$240	$37	$31
Interest cost	494	495	63	69
Expected return on plan assets	(449)	(502)	(58)	(62)
Amortization of transition obligation	-	-	18	19
Amortization of prior service cost	15	26	19	20
Amortization of unrecognized loss	92	37	4	3
Net periodic benefit cost	449	296	83	80
Less: transfer to regulatory account (1)	(225)	(104)	-	-
Total	$224	$192	$83	$80

(1) The Utility recorded these amounts to a regulatory account since they are probable of recovery from customers in future rates.

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

During 2012, the Pacific Gas and Electric Company Retirement Plan was amended to offer a new cash balance benefit formula. Eligible employees hired after December 31, 2012 will be covered by the new formula. Eligible employees hired before January 1, 2013 will have a one-time opportunity to elect to be covered by the new formula going forward, beginning on January 1, 2014. 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.

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 ("VIE"s) 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 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 10 below.) The Utility does not have any decision-making rights associated with the design of these VIEs, nor does the Utility have the power to direct the activities that are most significant to the economic performance of these VIEs such as dispatch rights, operating and maintenance activities, or re-marketing activities of the power plant after the termination of the VIEs' respective power purchase agreement with the Utility. Since the Utility was not the primary beneficiary of any of these VIEs at September 30, 2012, it did not consolidate any of them.

The Utility continued to consolidate the financial results of PG&E Energy Recovery Funding LLC ("PERF"), another VIE, at September 30, 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 ("ERB"s) 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 of the U.S. Bankruptcy Code ("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. The assets of PERF were $156 million at September 30, 2012 and primarily consisted of assets related to ERBs. The liabilities of PERF were $111 million at September 30, 2012 and consisted of ERBs, which are included in current liabilities in the Condensed Consolidated Balance Sheets. PERF is expected to be dissolved in 2013, after the ERBs mature. (See Note 4 below.)

At September 30, 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 Condensed Consolidated Balance Sheets. At September 30, 2012, PG&E Corporation had made total payments of $361 million under these agreements and received $225 million in benefits and customer payments. In determining whether PG&E Corporation is the primary beneficiary of any of these VIEs, it 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 September 30, 2012, it did not consolidate any of them.

Adoption of New Accounting Standards

Amendments to Fair Value Measurement Requirements

On January 1, 2012, PG&E Corporation and the Utility adopted an accounting standards update ("ASU") that requires additional fair value measurement disclosures. For fair value measurements that use significant unobservable inputs, quantitative disclosures of the inputs and qualitative disclosures of the valuation processes are required. For items not measured at fair value in the balance sheet but whose fair value is disclosed, disclosures of the fair value hierarchy level, the fair value measurement techniques used, and the inputs used in the fair value measurements are required. In addition, the ASU permits an entity to measure the fair value of a portfolio of financial instruments based on the portfolio's net position, if the portfolio has met certain criteria. Furthermore, the ASU refines when an entity should, and should not, apply certain premiums and discounts to a fair value measurement. The adoption of the ASU is reflected in Note 8 below and did not have a material impact on PG&E Corporation's or the Utility's Condensed Consolidated Financial Statements.

Presentation of Comprehensive Income

On January 1, 2012, PG&E Corporation and the Utility adopted ASUs that require an entity to present either (1) a single statement of comprehensive income or loss or (2) a separate statement of comprehensive income or loss that immediately follows a statement of income or loss. A single statement of comprehensive income or loss is comprised of a statement of income or loss with other comprehensive income and losses, total other comprehensive income or loss, and total comprehensive income or loss appended. A separate statement of comprehensive income or loss is comprised of net income or loss, other comprehensive income and losses, total other comprehensive income or loss, and total comprehensive income or loss. Furthermore, the ASUs prohibit an entity from presenting other comprehensive income and losses in a statement of equity only. The adoption of the ASUs resulted in the addition of the Condensed Consolidated Statements of Comprehensive Income to PG&E Corporation's and the Utility's Condensed Consolidated Financial Statements.

NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

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 that the costs are 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, amounts that are probable of being credited or refunded to customers in the future are recorded as regulatory liabilities.

The Utility tracks differences between customer billings and the Utility's authorized revenue requirements for revenue that is independent, or "decoupled," from the volume of electricity and natural gas sales. The Utility also tracks differences between incurred costs and customer billings or authorized revenue requirements meant to recover those costs. These differences are recorded to regulatory balancing accounts that represent amounts expected to be collected from or refunded to customers. Regulatory balancing accounts that are not expected to be collected from or refunded to customers over the next 12 months are included in other noncurrent assets – regulatory assets or noncurrent liabilities – regulatory liabilities, respectively, in the Condensed Consolidated Balance Sheets.

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

Regulatory Assets

Current Regulatory Assets

At September 30, 2012 and December 31, 2011, the Utility had current regulatory assets of $567 million and $1,090 million, respectively, primarily consisting of the price risk management regulatory asset, the Utility's retained generation regulatory assets, and the electromechanical meters regulatory asset. At December 31, 2011, current regulatory assets also included regulatory assets related to ERBs.

Long-Term Regulatory Assets

Long-term regulatory assets are composed of the following:

	Balance at	
(in millions)	September 30, 2012	December 31, 2011
Pension benefits	$3,019	$2,899
Deferred income taxes	1,584	1,444
Utility retained generation	567	613
Environmental compliance costs	576	520
Price risk management	223	339
Electromechanical meters	207	247
Unamortized loss, net of gain, on reacquired debt	147	163
Other	204	281
Total long-term regulatory assets	$6,527	$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 Condensed Consolidated Balance Sheets. (See Note 12 of the Notes to the Consolidated Financial Statements in the 2011 Annual Report.)

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 13 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 10 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 7 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 costs. These costs are expected to be recovered over the next 14 years, which is the remaining amortization period of the reacquired debt.

At September 30, 2012 and December 31, 2011, "other" primarily consisted of regulatory assets related to ARO expenses for the decommissioning of the Utility's fossil fuel-fired generation facilities that are probable of future recovery through rates and costs incurred related to the Utility's plan of reorganization under Chapter 11 that became effective in April 2004, which are being amortized and collected in rates through April 2034.

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 September 30, 2012 and December 31, 2011, the Utility had current regulatory liabilities of $379 million and $161 million, respectively, consisting of amounts that it expects to refund to customers over the next 12 months, primarily including electricity supplier settlement agreements. (See Note 9 below.) At September 30, 2012, current regulatory liabilities also included a U.S. Department of Energy ("DOE") settlement agreement. Current regulatory liabilities are included within current liabilities – other in the Condensed Consolidated Balance Sheets.

Long-Term Regulatory Liabilities

Long-term regulatory liabilities are composed of the following:

(in millions)	Balance at September 30, 2012	December 31, 2011
Cost of removal obligations	$3,595	$3,460
Recoveries in excess of AROs	649	611
Public purpose programs	613	499
Other	250	163
Total long-term regulatory liabilities	$5,107	$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 power facilities. Decommissioning costs recovered through rates are primarily placed in nuclear decommissioning trusts. The regulatory liability also represents the deferral of realized and unrealized gains and losses on the nuclear decommissioning trust investments. (See Note 8 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 residential 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.

At September 30, 2012 and December 31, 2011, "other" primarily consisted of the regulatory liability related to the gain associated with the Utility's acquisition of the permits and other assets of the Gateway Generating Station as part of the settlement that the Utility entered into with Mirant Corporation, the price risk management regulatory liability representing the unrealized gains associated with price risk management derivative instruments expected to be refunded to customers as they are realized beyond the next 12 months as part of the Utility's energy procurement costs (see Note 7 below), and the regulatory liability related to the tax benefit associated with SmartMeters.TM

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 Condensed Consolidated Balance Sheets.

Current Regulatory Balancing Accounts, Net

	Receivable (Payable) Balance at	
(in millions)	September 30, 2012	December 31, 2011
Distribution revenue adjustment mechanism	$92	$223
Utility generation	68	241
Hazardous substance	56	57
Public purpose programs	53	97
Gas fixed cost	105	16
Energy recovery bonds	(57)	(105)
Energy procurement	(19)	(48)
Other	151	227
Total regulatory balancing accounts, net	$449	$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 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 10 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 9 below.)

The Utility is generally authorized to recover 100% of its prudently incurred 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.

At September 30, 2012 and December 31, 2011, "other" consisted of various balancing accounts, such as the SmartMeterTM advanced metering project balancing account, which tracks the recovery of the related authorized revenue requirements and costs, and balancing accounts that track the recovery of authorized meter reading costs.

NOTE 4: DEBT

Revolving Credit Facilities – PG&E Corporation and the Utility

At September 30, 2012, PG&E Corporation had no cash borrowings or letters of credit outstanding under its $300 million revolving credit facility.

At September 30, 2012, the Utility had no cash borrowings and $330 million of letters of credit outstanding under its $3.0 billion revolving credit facility.

Utility

Senior Notes

On April 16, 2012, the Utility issued $400 million principal amount of 4.45% Senior Notes due April 15, 2042.

On August 16, 2012, the Utility issued $400 million principal amount of 2.45% Senior Notes due August 15, 2022 and $350 million principal amount of 3.75% Senior Notes due August 15, 2042.

Pollution Control Bonds

On April 2, 2012, the Utility repurchased the entire $50 million principal amount of pollution control bonds Series 2010 E that were subject to mandatory tender on that same date. The Utility will hold the bonds until they are remarketed to investors or retired.

At September 30, 2012, the interest rates on the $614 million principal amount of pollution control bonds Series 1996 C, E, F, and 1997 B and the related loan agreements ranged from 0.16% to 0.21%. At September 30, 2012, the interest rates on the $309 million principal amount of pollution control bonds Series 2009 A-D and the related loan agreements ranged from 0.17% to 0.20%.

Commercial Paper Program

At September 30, 2012, the Utility had $145 million of commercial paper outstanding.

Other Short-Term Borrowings

At September 30, 2012 the interest rate on the Utility's $250 million principal amount of Floating Rate Senior Notes, due November 20, 2012, was 0.88%.

Energy Recovery Bonds

At September 30, 2012, the total amount of ERB principal outstanding was $110 million. The ERBs mature on December 25, 2012.

While PERF is a wholly owned consolidated subsidiary of the Utility, it is legally separate from the Utility. The assets, including the right to be paid a specified amount collected through the Utility's electric rates (known as "recovery property"), of PERF are not available to creditors of the Utility or PG&E Corporation, and the recovery property is not legally an asset of the Utility or PG&E Corporation.

NOTE 5: EQUITY

PG&E Corporation's and the Utility's changes in equity for the nine months ended September 30, 2012 were as follows:

(in millions)	PG&E Corporation Total Equity		Utility Total Total Shareholders' Equity	
Balance at December 31, 2011	$	12,353	$	12,384
Comprehensive income		865		824
Common stock issued		720		-
Share-based compensation expense		41		1
Common stock dividends declared		(584)		(537)
Preferred stock dividend requirement		-		(10)
Preferred stock dividend requirement of subsidiary		(10)		-
Equity contributions		-		715
Balance at September 30, 2012	$	13,385	$	13,377

During the nine months ended September 30, 2012, PG&E Corporation issued 5,446,542 shares of its common stock under its 401(k) plan, its Dividend Reinvestment and Stock Purchase Plan, and its share-based compensation plans for total cash proceeds of $214 million.

During the nine months ended September 30, 2012, PG&E Corporation issued 5,446,760 shares of its common stock under the Equity Distribution Agreement executed in November 2011 for cash proceeds of $234 million, net of fees and commissions of $2 million. At September 30, 2012, PG&E Corporation had the ability to issue an additional $64 million of its common stock under the Equity Distribution Agreement.

On March 20, 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.

During the nine months ended September 30, 2012, PG&E Corporation contributed equity of $715 million to the Utility to maintain the Utility's CPUC-authorized capital structure, which consists of 52% common equity and 48% debt and preferred stock.

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NOTE 6: 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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions, except per share amounts)	2012	2011	2012	2011
Income available for common shareholders	$361	$200	$829	$761
Weighted average common shares outstanding, basic	428	403	422	399
Add incremental shares from assumed conversions:				
Employee share-based compensation	1	1	1	1
Weighted average common shares outstanding, diluted	429	404	423	400
Total earnings per common share, diluted	$0.84	$0.50	$1.96	$1.90

For each of the periods presented above, options and securities that were antidilutive were immaterial.

NOTE 7: 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 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. The CPUC allows the Utility to charge customer rates 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 Condensed 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 derivative instruments are deferred and recorded within the Utility's regulatory assets and liabilities on the Condensed Consolidated Balance Sheets. (See Note 3 above.) Net realized gains or losses 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 Condensed 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 enters into financial swap contracts to effectively fix the price of future purchases and reduce cash flow variability associated with fluctuating electricity prices. These financial swaps 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 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 purchases financial instruments, such as swaps and options, and 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 September 30, 2012, the volume of PG&E Corporation's and the Utility's outstanding derivatives was as follows:

		Contract Volume (1)			
Underlying Product	Instruments	Less Than 1 Year	Greater Than 1 Year but Less Than 3 Years	Greater Than 3 Years but Less Than 5 Years	Greater Than 5 Years (2)
Natural Gas (3) (MMBtus (4))	Forwards and Swaps	364,202,485	129,569,788	3,150,000	-
	Options	230,838,408	247,180,353	4,200,000	-
Electricity	Forwards and	2,978,823	3,927,621	2,009,505	2,689,804

(Megawatt-hours)	Swaps				
	Options	-	214,665	239,233	143,857
	Congestion Revenue Rights	53,856,688	75,797,340	74,225,248	34,225,866

(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 Condensed Consolidated Balance Sheets, derivatives are presented on a net basis by counterparty where the right of offset exists under a master netting agreement. The net balances include outstanding cash collateral associated with derivative positions.

At September 30, 2012, PG&E Corporation's and the Utility's outstanding derivative balances were as follows:

	Commodity Risk			
(in millions)	Gross Derivative Balance	Netting	Cash Collateral	Total Derivative Balance
Current assets – other	$52	$(37)	$75	$90
Other noncurrent assets – other	94	(36)	-	58
Current liabilities – other	(280)	37	119	(124)
Noncurrent liabilities – other	(259)	36	17	(206)
Total commodity risk	$(393)	$-	$211	$(182)

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

	Commodity Risk			
(in millions)	Gross Derivative Balance	Netting	Cash Collateral	Total Derivative 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)

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

	Commodity Risk			
	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2012	2011	2012	2011
Unrealized gain/(loss) - regulatory assets and liabilities (1)	$162	$(61)	$327	$97
Realized gain/(loss) - cost of electricity (2)	(108)	(149)	(383)	(406)
Realized gain/(loss) - cost of natural gas (2)	(5)	(4)	(32)	(66)
Total commodity risk	$49	$(214)	$(88)	$(375)

(1) Unrealized gains and losses on commodity risk-related derivative instruments are recorded to regulatory assets or liabilities, rather than being recorded to the Condensed 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 Condensed 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 September 30, 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 collateralize fully some of its net liability derivative positions.

At September 30, 2012, the additional cash collateral that the Utility would be required to post if the credit risk-related contingency features were triggered was as follows:

(in millions)	
Derivatives in a liability position with credit risk-related contingencies that are not fully collateralized	$(325)
Related derivatives in an asset position	74
Collateral posting in the normal course of business related to these derivatives	132
Net position of derivative contracts/additional collateral posting requirements (1)	$(119)

(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 8: 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.

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 September 30, 2012				
(in millions)	Level 1	Level 2	Level 3	Netting (1)	Total
Assets:					
Money market investments	$226	$-	$-	$-	$226
Nuclear decommissioning trusts					
Money market investments	25	-	-	-	25
U.S. equity securities	943	8	-	-	951
Non-U.S. equity securities	355	-	-	-	355
U.S. government and agency securities	725	145	-	-	870
Municipal securities	-	36	-	-	36
Other fixed-income securities	-	154	-	-	154
Total nuclear decommissioning trusts (2)	2,048	343	-	-	2,391
Price risk management instruments (Note 7)					
Electricity	2	71	60	12	145
Natural gas	-	9	4	(10)	3

Total price risk management instruments	2	80	64	2	148
Rabbi trusts					
Fixed-income securities	-	27	-	-	27
Life insurance contracts	-	71	-	-	71
Total rabbi trusts	-	98	-	-	98
Long-term disability trust					
U.S. equity securities	5	13	-	-	18
Non-U.S. equity securities	-	12	-	-	12
Fixed-income securities	-	130	-	-	130
Total long-term disability trust	5	155	-	-	160
Total assets	$2,281	$676	$64	$2	$3,023
Liabilities:					
Price risk management instruments (Note 7)					
Electricity	$191	$178	$148	$(195)	$322
Natural gas	12	10	-	(14)	8
Total liabilities	$203	$188	$148	$(209)	$330

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
(2) Excludes $236 million at September 30, 2012 primarily related to deferred taxes on appreciation of investment value.

	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 7)					
Electricity	-	92	69	8	169
Natural 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					
U.S. equity securities	13	15	-	-	28
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 7)					
Electricity	$411	$289	$143	$(441)	$402
Natural 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 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 Condensed 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 7 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.

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. There were no transfers between levels for the three and nine months ended September 30, 2012.

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 7 above.)

(in millions)	Fair Value at September 30, 2012				
Fair Value Measurement	Assets	Liabilities	Valuation Technique	Unobservable Input	Range (1)
Congestion revenue rights	$ 60	$ (8)	Market approach	CRR auction prices	$ (40.74) -$5.10
Power purchase agreements	$ -	$ (140)	Discounted cash flow	Forward prices	$ 7.87 - $ 61.84

(1) Represents price per megawatt-hour.

Level 3 Reconciliation

The following table presents the reconciliation for Level 3 price risk management instruments for the three and nine months ended September 30, 2012 and 2011:

	Price Risk Management Instruments	
(in millions)	2012	2011
Liability balance as of July 1	$ (80)	$ (280)
Realized and unrealized gains (losses):		
Included in regulatory assets and liabilities or balancing accounts (1)	(4)	(1)
Liability balance as of September 30	$ (84)	$ (281)

(1) Price risk management activity is recoverable through customer rates. Therefore, net income was not impacted by realized amounts. Unrealized gains and losses are deferred in regulatory liabilities and assets.

	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)	(10)	118
Liability balance as of September 30	$ (84)	$ (281)

(1) Price risk management activity is recoverable through customer rates. Therefore, net income was not impacted by realized amounts. 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 September 30, 2012 and December 31, 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, PG&E Corporation's fixed-rate senior notes, and the ERBs issued by PERF are based on quoted market prices at September 30, 2012 and 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):

	September 30, 2012		December 31, 2011	
(in millions)	Carrying Amount	Level 2 Fair Value	Carrying Amount	Level 2 Fair Value
Debt (Note 4)				
PG&E Corporation	$349	$376	$349	$380
Utility	11,644	14,151	10,545	12,543
Energy recovery bonds (Note 4)	110	111	423	433

Nuclear Decommissioning Trust Investments

The Utility classifies its investments held in the nuclear decommissioning trusts as "available-for-sale." As the day-to-day investing activities of the trusts 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. Realized gains and losses on the nuclear decommissioning trust investments are refundable or recoverable, respectively, through customer rates. Therefore, trust earnings are deferred and included in the regulatory liability for recoveries in excess of ARO. (See Note 3 above.) There is no impact on the Utility's net income or accumulated other comprehensive income.

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 September 30, 2012				
Money market investments	$25	$-	$-	$25
Equity securities				
U.S.	328	624	(1)	951
Non-U.S.	198	158	(1)	355
Debt securities				
U.S. government and agency securities	765	106	(1)	870
Municipal securities	32	4	-	36
Other fixed-income securities	149	5	-	154
Total	$1,497	$897	$(3)	$2,391
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 $236 million and $188 million at September 30, 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 September 30, 2012
Less than 1 year	$6
1–5 years	468
5–10 years	219
More than 10 years	367

Total maturities of debt securities	$1,060

28

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
(in millions)				
Proceeds from sales and maturities of nuclear decommissioning trust investments	$237	$567	$903	$1,574
Gross realized gains on sales of securities held as available-for-sale	3	11	17	40
Gross realized losses on sales of securities held as available-for-sale	(6)	(7)	(13)	(14)

NOTE 9: 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 between May 2000 and June 2001.

In addition to various prior hearings relating to the Utility's claims, the FERC recently held hearings to consider the Utility's and other electricity purchasers' refund claims for the May through September 2000 period. The hearings concluded on July 19, 2012, but the FERC has not yet issued a decision. An initial decision is expected in February 2013.

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 many of the 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 both parties 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 Condensed Consolidated Balance Sheets at September 30, 2012, reflecting its intent and right to offset these amounts. At December 31, 2011, $494 million was included within accounts receivable – other on the Condensed 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	20
Less: electricity supplier settlements	(24)
Balance at September 30, 2012	$844

At September 30, 2012, the remaining net disputed claims liability consisted of $164 million of remaining net disputed claims (classified on the Condensed Consolidated Balance Sheets within accounts payable – disputed claims and customer refunds) and $680 million of accrued interest (classified on the Condensed Consolidated Balance Sheets within interest payable).

At September 30, 2012 and December 31, 2011, the Utility held $301 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 Condensed 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, 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 10: 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 guarantees, regulatory proceedings, nuclear operations, legal matters, environmental remediation, and tax matters.

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 gas or electricity at the date of purchase. The Utility's obligations under a significant portion of these agreements are contingent on the third party's development of new generation facilities to provide the power to be purchased by the Utility under these agreements. The table below excludes expected future payments related to agreements ranging from 10 to 25 years in length that are cancellable if the construction of a new generation facility has not met certain contractual milestones with respect to construction. Based on the Utility's experience with these types of facilities, the Utility has determined that there is more than a remote chance that contracts could be cancelled until the construction of the generating facilities has commenced.

At September 30, 2012, the undiscounted future expected payment obligations were as follows:

(in millions)	
2012	$608
2013	3,075
2014	3,405
2015	3,418
2016	3,287
Thereafter	39,341
Total	$53,134

Costs incurred by the Utility under power purchase agreements amounted to $1.7 billion and $1.8 billion for the nine months ended September 30, 2012 and 2011, respectively.

Some of the power purchase agreements that the Utility entered into with independent power producers that are qualifying facilities are treated as capital leases. During the nine months ended September 30, 2012, the Utility terminated several agreements with total minimum lease payments of approximately $136 million. The future minimum lease payments associated with the remaining capital leases were approximately $125 million.

Natural Gas Supply, Transportation, and Storage Commitments

The Utility purchases natural gas directly from producers and marketers in both Canada and the U.S. 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 U.S. Rocky Mountain supply area, and the southwestern U.S.) 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 better meet core customers' winter peak loads.

At September 30, 2012, the Utility's undiscounted future expected payment obligations were as follows:

(in millions)	
2012	$254
2013	535
2014	198
2015	188
2016	153
Thereafter	974
Total	$2,302

Costs incurred for natural gas purchases, natural gas transportation services, and natural gas storage amounted to $924 million and $1.3 billion for the nine months ended September 30, 2012 and 2011, respectively.

Nuclear Fuel Agreements

The Utility has entered into several purchase agreements for nuclear fuel. These agreements have terms ranging from one to 14 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 2016, 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 September 30, 2012, the undiscounted future expected payment obligations were as follows:

(in millions)	
2012	$7
2013	84
2014	127
2015	192
2016	147
Thereafter	1,022
Total	$1,579

Payments for nuclear fuel amounted to $79 million and $55 million for the nine months ended September 30, 2012 and 2011, respectively.

Other Commitments

In March and September 2012, the Utility entered into 10-year facility lease agreements for 250,000 and 145,000 square feet of office space, respectively, in San Ramon, California. At September 30, 2012, the future minimum commitment for these operating leases was approximately $101 million.

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 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 $32 million at September 30, 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 Condensed 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.

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 CPUC's Consumer Protection and Safety Division ("CPSD") issued investigative reports in each of these investigations alleging that the Utility committed numerous violations of applicable laws and regulations and recommending the CPUC impose penalties on the Utility. (See "Penalties Conclusion" below.) The CPUC began hearings in each of the investigations. On September 26, 2012, the CPUC administrative law judges overseeing the investigations issued a joint ruling granting the CPSD's request to file a single coordinated brief regarding potential remedies and penalties in these investigative proceedings, rather than separate briefs in each proceeding. On October 11, 2012, the procedural schedule was suspended until November 1, 2012 to enable the Utility, the CPSD, and other parties to continue to engage in negotiations to reach a stipulated outcome of these proceedings. Any settlement agreement that may be reached would be submitted to the CPUC for its consideration. The CPUC would hold public hearings before issuing a final decision.

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

On February 24, 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 CPSD submitted testimony alleging that the Utility committed numerous violations of applicable laws and regulations based on the findings of the CPSD'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. On June 26, 2012, the Utility submitted testimony to the CPUC that disputed many of the CPSD's findings and allegations, but acknowledged that improvements are needed to its asset management system and recordkeeping practices and outlined the steps being taken in these areas.

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

On November 10, 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 ("MAOP") up to which a pipeline can be operated. In its May 25, 2012 investigative report, the CPSD cited the Utility's admissions in previous reports to the CPUC that it had failed to classify pipeline segments properly and document past patrols of transmission lines and concluded that these failures resulted in numerous violations of state and federal standards. On July 23, 2012, the Utility submitted testimony in response to the CPSD'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 September 2012.

CPUC Investigation Regarding the San Bruno Accident

On January 12, 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 CPSD. In its January 12, 2012 investigation report, the CPSD had 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 management requirements, the Utility's inadequate record keeping practices, deficiencies in the Utility's data collection and reporting system, 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.

On June 26, 2012, the Utility submitted testimony to the CPUC that disputed many of the CPSD's findings and allegations. The Utility 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 CPSD's reports are not deficiencies, or are much less severe than alleged, and do not constitute violations of applicable laws and regulations.

Other Natural Gas Compliance 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 utilities' natural gas operating practices. The CPSD has been delegated authority from the CPUC to enforce compliance with these regulations. As of September 30, 2012, the Utility has submitted 29 self-reports with the CPUC, plus additional follow-up reports. In a self-report filed on October 19, 2012, the Utility reported that it does not have documentation substantiating that approximately 4.5 miles of pipe had undergone integrity assessments prior to December 17, 2007, as required by federal regulations. In April 2012, the CPUC affirmed a $17 million penalty that had been imposed by the CPSD 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 completed all of the missed leak surveys.) The CPSD has not yet taken action with respect to the Utility's other self-reports. The CPSD 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 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 property easements and that the Utility plans to undertake a multi-year effort to clear these encroachments. PG&E Corporation and the Utility are uncertain how this matter will affect the investigative proceedings related to natural gas operations, or whether additional proceedings or investigations will be commenced by the CPUC.

Penalties Conclusion

The CPUC can impose significant penalties for violations of applicable laws, rules, and orders in connection with the pending investigations and enforcement matters described above. The CPUC and the CPSD have wide discretion to determine the number of violations and the length of time the violations existed. The calculation of penalties is generally based on the totality of the circumstances, including such factors as the severity of the violations; the type of harm caused by the violations and the number of persons affected; conduct taken to prevent, detect, disclose or rectify the violations; and the financial resources of the regulated entity.

PG&E Corporation and the Utility continue to believe it is probable that the Utility will incur total penalties of at least $200 million in connection with these investigations and enforcement matters. PG&E Corporation and the Utility have not recorded any additional charges during the nine months ended September 30, 2012 and are unable to estimate the reasonably possible amount of penalties in excess of the amount accrued, and such amounts could be material. These estimates, and the assumptions on which they are based, are subject to change based on many factors, including developments that may occur during the settlement negotiations, the terms of any proposed settlement agreement that may be reached, whether and when the CPUC approves the proposed settlement agreement, and rulings and decisions by the CPUC and the administrative law judges presiding over these proceedings. Future changes in these estimates or assumptions could have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

CPUC 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. The CPUC is considering proposed implementation plans that were filed in August 2011 by the Utility and other California natural gas pipeline operators. The Utility forecasted its total plan-related capital expenditures over a four-year period (2011 through 2014) would be approximately $1.4 billion and requested that the CPUC authorize the Utility to recover these expenditures through rates. On October 12, 2012, the administrative law judge overseeing the proceeding issued a proposed decision that recommended disallowing rate recovery for $401 million of the $1.4 billion requested. At

September 30, 2012, PG&E Corporation’s and the Utility’s Condensed Consolidated Balance Sheets include capitalized expenditures of approximately $187 million that the Utility incurred under its proposed plan. If the proposed decision is adopted by the CPUC, disallowed capital investments would be charged to net income in the period in which the CPUC orders such a disallowance.

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.

Third-Party Claims

In addition to the investigations and proceedings discussed above, at September 30, 2012, approximately 130 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 420 plaintiffs. The lawsuits seek compensation for personal injury and property damage, and other relief, including punitive damages. These cases have been coordinated and assigned to one judge in the San Mateo County Superior Court. As of October 26, 2012, approximately 70 plaintiffs have settled their claims. The trial date for the first group of the remaining plaintiffs is currently scheduled for January 2, 2013. PG&E Corporation and the Utility have filed a motion to dismiss the remaining plaintiffs' claims for punitive damages based upon a lack of evidence to support such claims. The court has set a hearing date for October 29, 2012 to consider the motion.

At September 30, 2012, the Utility has recorded a cumulative charge of $455 million for estimated third-party claims related to the San Bruno accident, including an $80 million charge made during the second quarter of 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 the changes in third-party claims liability since the San Bruno accident in 2010, which is included in other current liabilities in PG&E Corporation's and the Utility's Condensed 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	(173	)
Balance at September 30, 2012	$184	

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 this insurance coverage is approximately $992 million in excess of a $10 million deductible. At September 30, 2012, the Utility has recognized cumulative insurance recoveries of $234 million, including $99 million and $135 million during the three and nine months ended September

30, 2012. 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 future insurance recoveries.

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 CPSD's January 2012 investigative report 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 CPSD recommended that the Utility should use such amounts to fund future gas transmission expenditures and operations. (See the 2011 Annual Report.) 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. On October 9, 2012, PG&E Corporation and the Utility requested the court to 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 have requested that the court order the plaintiffs to delay proceeding on the complaint until the CPUC investigations described above are concluded. The court has set a hearing for December 17, 2012. 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 Proceeding

Under the Nuclear Waste Policy Act of 1982, the DOE and electric utilities with commercial nuclear power plants were authorized to enter into contracts under which the DOE would be required to dispose of the utilities' spent nuclear fuel and high-level radioactive waste by January 1998, in exchange for fees paid by the utilities. The DOE has been unable to meet its contractual obligation with the Utility to dispose of nuclear waste from the Utility's two nuclear generating units at Diablo Canyon and 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 ("DOJ") and the Utility executed a settlement agreement that awarded the Utility $266 million for spent fuel storage costs incurred through December 31, 2010. At September 30, 2012, this amount was recorded as a receivable in PG&E Corporation's and the Utility's Condensed Consolidated Financial Statements. 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 $25 million per year. Amounts recovered from the DOE will be refunded to customers through rates in future periods. 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 fuel.

Nuclear Insurance

The Utility has several types of nuclear insurance for the two nuclear generating units at Diablo Canyon and Humboldt Bay Unit 3. The Utility has insurance coverage for property damages and business interruption losses as a member of Nuclear Electric Insurance Limited ("NEIL"). NEIL is a mutual insurer owned by utilities with nuclear facilities. NEIL provides property damage and business interruption coverage of up to \$3.2 billion per incident (\$2.7 billion for property damage and \$490 million for business interruption) for Diablo Canyon. In addition, NEIL provides \$131 million of property damage insurance for Humboldt Bay Unit 3. 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 ("S&T") insurance policies. The Utility has a S&T 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.

Guarantees

PG&E Corporation retains a guarantee related to certain obligations of its former subsidiary, National Energy & Gas Transmission, Inc. ("NEGT"), that were issued to the purchaser of an NEGT subsidiary company in 2000. PG&E Corporation's primary remaining exposure relates to any potential environmental obligations that were known to NEGT at the time of the sale but not disclosed to the purchaser, and is limited to $150 million. PG&E Corporation has not received any claims nor does it consider it probable that any claims will be made under the guarantee. PG&E Corporation believes that if it were required to satisfy its obligations under this guarantee, any required payments would not have a material impact on its financial condition, results of operations, or 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 ("MGP") 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, 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 from December 31, 2011:

(in millions)	
Balance at December 31, 2011	$785
Additional remediation costs accrued:	
Transfer to regulatory account for recovery	119
Amounts not recoverable in customer rates	127
Less: Payments	(118)
Balance at September 30, 2012	$913

The environmental remediation liability is composed of the following:

	Balance at	
(in millions)	September 30, 2012	December, 31 2011
Utility-owned natural gas compressor site near Hinkley, California (1)	$227	$149
Utility-owned natural gas compressor site near Topock, Arizona (1)	236	218
Utility-owned generation facilities (other than for fossil fuel-fired), other facilities, and third-party disposal sites	162	133
Former MGP sites owned by the Utility or third parties	178	154
Fossil fuel-fired generation facilities formerly owned by the Utility	87	81
Decommissioning fossil fuel-fired generation facilities and sites	23	50
Total environmental remediation liability	$913	$785

(1) See "Natural Gas Compressor Sites" 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 September 30, 2012, the Utility expected to recover $550 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 and Topock, Arizona. 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.

In June 2012, the Regional Board issued an amended cleanup and abatement order to allow the Utility to implement a voluntary whole house water replacement program for approximately 300 resident households located within or near the chromium plume boundary. Eligible residents were given until October 15, 2012 to decide whether to accept a replacement water supply or have the Utility purchase their properties, or alternatively not participate in the program. The majority of eligible residents opted to accept the Utility's offer to purchase their property. 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.

In August 2012, the Regional Board issued a draft environmental impact report ("EIR") that evaluated several alternatives for remediating groundwater contamination using a combination of different remedial methods, including using pumped groundwater from extraction wells to irrigate agricultural land and in-situ treatment of the contaminated water. The Utility expects that the Regional Board will consider certification of the final EIR in 2013.

At September 30, 2012, $227 million was accrued in PG&E Corporation's and the Utility's Condensed Consolidated Balance Sheets for estimated undiscounted future remediation costs associated with the Hinkley natural gas compressor site, compared to $149 million accrued at December 31, 2011. The increase primarily reflects the Utility's best estimate of costs associated with providing water replacement systems to eligible residents or purchasing property from eligible residents, as described above. Remediation costs for the Hinkley natural gas compressor site are not recovered from customers.

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, estimates and assumptions regarding the amount of liability incurred may be subject to further changes. Future changes in estimates may have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

Topock Site

The Utility's remediation and abatement efforts at the Topock site are subject to the regulatory authority of the California 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 remedyand plans to submit its intermediate design plan to the DTSC and DOI in January 2013 and a final plan for approval in late 2013. 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 September 30, 2012, $236 million was accrued in PG&E Corporation's and the Utility's Condensed Consolidated Balance Sheets for estimated undiscounted future remediation costs associated with the Topock site, compared to $218 million accrued at December 31, 2011. 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, estimates and assumptions regarding the amount of liability incurred may be subject to change. The Utility expects to recover 90% of its remediation costs for the Topock site from customers. Future changes in estimates 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 $1.7 billion (including amounts related to the Hinkley and Topock natural gas compressor sites discussed 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.

Tax Matters

In 2008, PG&E Corporation began participating in the Compliance Assurance Process ("CAP"), a real-time Internal Revenue Service ("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 relates to a tax accounting method change filed by PG&E Corporation to accelerate the amount of deductible repairs. In the fourth quarter 2011, the IRS agreed to allow PG&E Corporation to file claims for 2008-2010 for the repairs method change. The IRS has not completed its review of these claims.

The IRS is continuing to work with the utility industry to provide consistent repairs deduction guidance for natural gas transmission, natural gas distribution, and electric generation businesses. PG&E Corporation and Utility expect the

IRS to release this guidance during the remainder of 2012 or 2013.

PG&E Corporation and the Utility are unable to determine a range of reasonably possible impacts resulting from future changes to the unrecognized tax benefits at this time.

ITEM 2. 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 five million electricity distribution customers and approximately four million natural gas distribution customers at September 30, 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.

Most of the Utility's base revenues ("revenue requirements") that the Utility is authorized to collect through rates are set by the CPUC in the General Rate Case ("GRC"), which occurs generally every three years. The Utility's revenue requirements for other portions of its operations, such as electric transmission, natural gas transportation and storage services, electricity and natural gas purchases, are authorized in other regulatory proceedings overseen by the CPUC or the FERC. The Utility's revenue requirements are generally set at a level to allow the Utility to recover its forecasted operating expenses, to recover depreciation, tax, and interest expenses associated with forecasted capital expenditures, and to provide the Utility with an opportunity to earn its authorized rate of return on equity ("ROE"). The Utility also collects revenue requirements to recover certain costs that the CPUC has authorized the Utility to pass through to customers, such as electricity procurement costs. From time to time, the Utility also files separate applications with the CPUC requesting authority to recover costs for other projects. PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows are affected by the extent to which the Utility is able to timely recover its actual costs through rates and earn its authorized ROE.

This is a combined quarterly report of PG&E Corporation and the Utility and should be read in conjunction with each company's separate Condensed Consolidated Financial Statements and the Notes to the Condensed Consolidated Financial Statements included in this quarterly report. In addition, this quarterly report should be read in conjunction with PG&E Corporation's and the Utility's combined Annual Report on Form 10-K for the year ended December 31, 2011 which contains or incorporates by reference each company's audited Consolidated Financial Statements, the Notes to the Consolidated Financial Statements, and other information ("2011 Annual Report").

Key Factors Affecting Results of Operations and Financial Condition

During 2012, 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"). The outcome of these matters and a number of other factors have had, and will continue to have, a material 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 total unrecoverable pipeline-related expenses could be as much as $550 million in 2012, including $371 million incurred during the nine months ended September 30, 2012 to validate pipeline operating pressures, conduct strength tests, and perform other work within the scope of the Utility's proposed pipeline safety enhancement plan, as well as legal and regulatory costs. (See "Operating and Maintenance" below.) On October 12, 2012, a proposed decision was issued that, if adopted by the CPUC, would disallow rate recovery for a significant portion of plan-related expenses and capital expenditures requested in the Utility's proposed plan. (See "CPUC Gas Safety Rulemaking Proceeding" below.) PG&E Corporation and the Utility also continue to believe that the CPUC will impose penalties on the Utility of at least $200 million in connection with the CPUC's investigations and enforcement matters and that the ultimate amount of penalties could be materially higher. (See Note 10 to the Condensed Consolidated Financial Statements and "Natural Gas Matters" below.) PG&E Corporation and the Utility also believe it is reasonably possible that they may incur additional charges of up to $145 million for third-party claims related to the San Bruno accident. An ongoing investigation of the San Bruno accident by federal, state, and local authorities also may result in the imposition of civil or criminal penalties on the Utility. PG&E Corporation's and the Utility's future financial condition, results of operations, and cash flows may also be affected by additional civil or criminal penalties, or punitive damages, if any, that the Utility may be required to pay.

- Authorized Rate of Return, Capital Structure, and Financing. PG&E Corporation contributes equity to the Utility as needed by the Utility to maintain its CPUC-authorized capital structure for its electric and natural gas distribution and electric generation rate base, consisting of 52% common equity and 48% debt and preferred stock. The Utility has incurred significant costs that are not recoverable through rates, which has increased the Utility's equity financing needs. For the nine months ended September 30, 2012, the Utility received equity contributions from PG&E Corporation of approximately $715 million, which were funded primarily through common stock issuances. The Utility's future equity financing needs will be affected by the ultimate amount of unrecoverable costs and penalties incurred in connection with natural gas matters discussed above. Additional equity issued by PG&E Corporation in the future could have a material dilutive effect on PG&E Corporation's earnings per common share. In addition, the Utility's net income and PG&E Corporation's income available for common shareholders in 2013 and future years may be affected by changes in the Utility's authorized capital structure and ROE, currently set at 11.35%, including any reductions that may be made to ROE for authorized capital expenditures incurred under the Utility's pipeline safety enhancement plan. (See "2013 Cost of Capital Proceeding" and "CPUC Gas Safety Rulemaking Proceeding" below.) The Utility's financing needs also will be affected by other factors, including the expiration of the accelerated (or "bonus") depreciation provisions of the federal Tax Relief Act in 2013, and the timing and amount of the Utility's capital expenditures, operating expenses, and collateral requirements associated with price risk management activities. 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 and Other Regulatory Proceedings. The Utility's financial results are affected by the timing and outcome of rate case decisions and other proceedings. As described in the 2011 Annual Report, the CPUC issued decisions in 2011 that determined the majority of the Utility's base revenue requirements through 2013 or later. The Utility intends to file its 2014 GRC application with the CPUC before the end of 2012. In the 2014 GRC, the CPUC will determine the amount of revenue requirements the Utility can collect through rates for its electric generation operations and electric and natural gas distribution from 2014 through 2016. (See "2014 General Rate Case" below.) On September 28, 2012, the Utility filed its Transmission Owner ("TO") rate case application with the FERC requesting an increase of $254 million in electric transmission rates over the estimated revenues that the Utility would receive in 2013 based on present rates. (See "TO Rate Case" below.) Further, as noted above, the Utility's future financial results will be affected by the timing and outcome of the CPUC's final decision regarding the Utility's proposed pipeline safety enhancement plan and the outcome of the pending investigations related to natural gas matters. (See "Natural Gas Matters – CPUC Gas Safety Rulemaking Proceeding" below.) In addition, the CPUC is expected to issue a decision by December 31, 2012 on the Utility's application to change its capital structure and rates of return on each component beginning on January 1, 2013. The outcome of these regulatory 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. In addition to the expenses related to the Utility's proposed pipeline safety enhancement plan and the other natural gas matters described above, the Utility incurred expenses in the nine months ended September 30, 2012 that are $176 million higher than amounts authorized in the 2011 rate cases to improve the safety and reliability of its electric and natural gas operations. The Utility forecasts that these incremental expenses, which are not recoverable through rates, will total approximately $250 million in 2012. The Utility expects that it will continue to incur these incremental and non-recoverable costs in 2013 as the Utility continues to work to improve the safety and reliability of its operations. (See "Results of Operations" below.) The Utility plans to request that the CPUC authorize increased revenue requirements in the 2014 GRC and the 2015 Gas Transmission and Storage ("GT&S") rate case to allow the Utility to recover the higher level of expenses it anticipates it will incur. In addition, 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 future financial condition, results of operations, and cash flows. (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 and negatively affect the amount of PG&E Corporation's future income available for common shareholders.

Summary of Changes in Earnings per Common Share and Income Available for Common Shareholders for the Three and Nine Months Ended September 30, 2012

The following table is a summary reconciliation of the key changes in PG&E Corporation's income available for common shareholders and earnings per common share for the three and nine months ended September 30, 2012:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions, except per share amounts)	Earnings	Earnings Per Common Share (Diluted)	Earnings	Earnings Per Common Share (Diluted)
Income Available for Common Shareholders – September 30, 2011	$200	$0.50	$761	$1.90
Increase in rate base earnings	20	0.05	62	0.14
Litigation and regulatory matters	10	0.02	34	0.08
Storm and outage expenses	-	-	34	0.08
Environmental-related costs	60	0.15	18	0.06
Gas transmission revenues	-	-	14	0.03
Natural gas matters	138	0.34	8	0.05
Planned incremental work	(42)	(0.10)	(104)	(0.24)
Increase in shares outstanding (1)	-	(0.06)	-	(0.14)
Other	(25)	(0.06)	2	-
Income Available for Common Shareholders – September 30, 2012	$361	$0.84	$829	$1.96

(1) Represents the impact of a higher number of shares outstanding at September 30, 2012, compared to the number of shares outstanding at September 30, 2011. PG&E Corporation issues shares to fund its equity contributions to the Utility that are used by the Utility to maintain its 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 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 capital expenditures; estimated environmental remediation, tax, and other liabilities; estimates and assumptions used in PG&E Corporation's and the Utility's critical accounting policies; estimated losses associated with various investigations, enforcement matters, and regulatory proceedings pertaining to the San Bruno accident and the Utility's natural gas operations; estimated losses and insurance recoveries associated with the civil litigation arising from the San Bruno accident; estimated additional costs the Utility will incur related to its natural gas and electric operations; estimated future cash flows; and the amount of future equity or debt financings. These statements are also identified by words such as "assume," "expect," "intend," "forecast," "plan," "project," "believe," "estimate," "target," "predict," "anticipate," "aim," "may "would," "could," "goal," "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, 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 regulatory proceedings, such as the CPUC's natural gas rulemaking proceeding, and the outcome of ratemaking proceedings, such as the 2014 GRC and the 2013 cost of capital proceeding;

- the ultimate amount of costs the Utility incurs in the future that are not recovered through rates, including costs incurred under its pipeline safety enhancement plan, and additional costs incurred to perform incremental work to improve the safety and reliability of its 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 (in addition to investigations or proceedings related to the San Bruno accident and natural gas matters);

- 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 San Bruno accident and the related civil litigation, the occurrence of adverse developments in the CPUC investigations or the criminal investigation, including any 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 results of seismic studies the Utility is conducting that could affect the Utility's ability to continue operating its Diablo Canyon nuclear power plant ("Diablo Canyon") or renew the operating licenses for Diablo Canyon, and the impact of new legislation, regulations, recommendations or policies applicable to the operations, security, safety, or decommissioning of nuclear facilities, the storage of spent nuclear fuel, seismic design, cooling water intake, or other issues;

- 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 newly installed advanced metering system infrastructure, customer billing, financial, and other systems, continue to function accurately; whether the Utility can modify its operating systems and networks as needed to timely implement "dynamic pricing" retail electric rates and comply with other requirements established by the CPUC; 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 from unauthorized access and disclosure; 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

- the outcome of federal or state tax audits and the impact of any changes in federal or state tax laws, policies, or regulations.

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 the discussion in the section entitled "Risk Factors" in the 2011 Annual Report and Item 1A. 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 Condensed Consolidated Statements of Income for the three and nine months ended September 30, 2012 and 2011:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2012	2011	2012	2011
Utility				
Electric operating revenues	$3,321	$3,187	$9,022	$8,691
Natural gas operating revenues	653	672	2,184	2,447
Total operating revenues	3,974	3,859	11,206	11,138
Cost of electricity	1,283	1,224	3,104	3,018
Cost of natural gas	118	170	593	936
Operating and maintenance	1,343	1,497	4,134	3,951
Depreciation, amortization, and decommissioning	617	566	1,807	1,648
Total operating expenses	3,361	3,457	9,638	9,553
Operating Income	613	402	1,568	1,585
Interest income	2	2	5	6
Interest expense	(172)	(171)	(511)	(511)
Other income, net	19	19	64	52
Income before income taxes	462	252	1,126	1,132
Income tax provision	122	56	328	376
Net Income	340	196	798	756
Preferred stock dividend requirement	3	3	10	10
Income Available for Common Stock	$337	$193	$788	$746
PG&E Corporation, Eliminations, and Other(1)				
Operating revenues	$2	$1	$4	$3
Operating expenses (income)	1	(5)	4	4
Operating Income (Loss)	1	6	-	(1)
Interest income	-	-	1	1
Interest expense	(6)	(5)	(17)	(16)
Other income (expense), net	7	(1)	20	4
Income (loss) before income taxes	2	-	4	(12)
Income tax benefit	(22)	(7)	(37)	(27)
Net Income	$24	$7	$41	$15
Consolidated Total				
Operating revenues	$3,976	$3,860	$11,210	$11,141
Operating expenses	3,362	3,452	9,642	9,557
Operating Income	614	408	1,568	1,584
Interest income	2	2	6	7
Interest expense	(178)	(176)	(528)	(527)
Other income, net	26	18	84	56
Income Before Income Taxes	464	252	1,130	1,120
Income tax provision	100	49	291	349
Net Income	364	203	839	771
Preferred stock dividend requirement of subsidiary	3	3	10	10
Income Available for Common Shareholders	$361	$200	$829	$761

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

The following presents the Utility's operating results for the three and nine months ended September 30, 2012 and 2011.

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 electricity procurement costs and the costs of public purpose, energy efficiency, and demand response programs.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2012	2011	2012	2011
Revenues excluding pass-through costs	$1,616	$1,573	$4,763	$4,595
Revenues for recovery of passed-through costs	1,705	1,614	4,259	4,096
Total electric operating revenues	$3,321	$3,187	$9,022	$8,691

The Utility's total electric operating revenues, including revenues intended to recover costs that are passed through to customers, increased by $134 million, or 4%, in the three months ended September 30, 2012 and by $331 million, or 4%, in the nine months ended September 30, 2012, as compared to the same periods in 2011. Revenues intended to recover costs that are passed through to customers and do not impact net income increased by $91 million and $163 million in the three and nine months ended September 30, 2012, respectively, as compared to the same periods in 2011, primarily due to an increase in cost of electricity. (See "Cost of Electricity" below.)

Electric operating revenues, excluding revenues intended to recover costs that are passed through to customers, increased by $43 million and $168 million in the three and nine months ended September 30, 2012, respectively, as compared to the same periods in 2011. The increase for both periods is primarily due to an increase in base revenues as authorized in the 2011 GRC decision.

The Utility's future electric operating revenues, excluding revenues intended to recover costs that are passed through to customers, are expected to increase during the remainder of 2012 and in 2013 as authorized by the CPUC in the 2011 GRC. Additionally, the Utility's future electric operating revenues are also expected to increase as authorized by the FERC in the TO rate case. These future electric operating revenues will 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 7 of the Notes to the Condensed 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 system, which are included in operating and maintenance expense in the Condensed Consolidated Statements of Income.

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

	Three Months Ended	Nine Months Ended

(in millions)	September 30, 2012	2011	September 30, 2012	2011
Cost of purchased power	$1,214	1,141	$2,896	$2,819
Fuel used in own generation facilities	69	83	208	199
Total cost of electricity	$1,283	$1,224	$3,104	$3,018
Average cost of purchased power per kWh (1)	$0.088	0.092	$0.079	0.089
Total purchased power (in millions of kWh)	13,720	12,446	36,539	31,582

(1) Kilowatt-hour

The Utility's total cost of electricity increased by $59 million, or 5%, in the three months ended September 30, 2012 and by $86 million, or 3%, in the nine months ended September 30, 2012, as compared to the same periods in 2011, primarily due to an increase in the volume of purchased power, which was partially offset by the decrease in the average cost of purchased power. The volume of power the Utility purchases is driven by load, the availability of the Utility's own generation facilities, and the cost effectiveness of each source of electricity.

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 load. 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 program expenses.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2012	2011	2012	2011
Revenues excluding pass-through costs	$433	$422	$1,320	$1,275
Revenues for recovery of passed-through costs	220	250	864	1,172
Total natural gas operating revenues	$653	672	$2,184	$2,447

The Utility's natural gas operating revenues, including revenues intended to recover costs that are passed through to customers, decreased by $19 million, or 3%, and by $263 million, or 11%, in the three and nine months ended September 30, 2012, respectively, as compared to the same periods in 2011. Revenues intended to recover costs that are passed through to customers and do not impact net income decreased by $30 million and $308 million in the three and nine months ended September 30, 2012, respectively, as compared to the same periods in 2011, 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 $11 million and by $45 million in the three and nine months ended September 30, 2012, respectively, as compared to the same periods in 2011. The increase for both periods is primarily due to an increase in base revenues as authorized in the 2011 GT&S rate case and GRC decisions and increases in natural gas storage revenues.

The Utility's operating revenues for natural gas transmission and storage services in 2013 and 2014 will reflect revenue increases that have been authorized by the CPUC in the 2011 GT&S rate case decision. 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 decision. Additionally, the Utility's future operating revenues will reflect those revenues authorized by the CPUC under the Utility's proposed pipeline safety enhancement plan. (See "Natural Gas Matters" below.) The Utility's future gas operating revenues also will be impacted by changes in 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 7 of the Notes to the Condensed Consolidated Financial Statements.) The Utility's cost of natural gas is passed through to customers. The cost of natural gas excludes the cost of transportation on the Utility's pipeline system, which is included in operating and maintenance expense in the Condensed Consolidated Statements of Income.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2012	2011	2012	2011
Cost of natural gas sold	$75	$128	$454	$802
Transportation cost of natural gas sold	43	42	139	134
Total cost of natural gas	$118	$170	$593	$936
Average cost per Mcf of natural gas sold	$2.42	$3.88	$2.52	$4.20
Total natural gas sold (in millions of Mcf) (1)	31	33	180	191

(1) One thousand cubic feet.

The Utility's total cost of natural gas decreased by $52 million, or 31%, and by $343 million, or 37%, in the three and nine months ended September 30, 2012, respectively, as compared to the same periods in 2011. These decreases were primarily due to a lower average market price of natural gas during 2012.

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 the success of its ability to manage its expenses and to achieve operational and cost efficiencies.

The Utility's operating and maintenance expenses decreased by $154 million, or 10%, from $1,497 million in the three months ended September 30, 2011 to $1,343 million in the three months ended September 30, 2012. The total decrease in operating and maintenance expense was primarily due to a $233 million decrease in net costs associated with natural gas matters (see table below) and a $76 million decrease in environmental remediation costs associated with the Hinkley natural gas compressor site, which were partially offset by approximately $40 million of increased labor and benefit-related costs, and costs to improve the safety and reliability of the Utility's electric and natural gas operations that were $72 million higher than amounts assumed under the 2011 rate cases.

The Utility's operating and maintenance expenses increased by $183 million, or 5%, from $3,951 million in the nine months ended September 30, 2011 to $4,134 million in the nine months ended September 30, 2012. The total increase in operating and maintenance expense was primarily due to costs incurred to improve the safety and reliability of electric and natural gas operations that were $176 million higher than amounts assumed under the 2011 rate cases and approximately $80 million of increased labor and benefit-related costs, which were partially offset by a $58 million decrease in storm-related costs, a $24 million decrease in environmental remediation costs associated with the Hinkley natural gas compressor site, and a $12 million decrease in net costs associated with natural gas matters (see table below).

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

	Three Months Ended	Nine Months Ended

(in millions)	September 30, 2012	2011	September 30, 2012	2011
Pipeline-related costs	$139	$177	$371	$303
Third-party liability	-	96	80	155
Insurance recoveries	(99)	-	(135)	(60)
Contributions	-	-	70	-
Total natural gas matters	$40	$273	$386	$398

The Utility incurred net costs of $40 million and $386 million during the three and nine months ended September 30, 2012, respectively, in connection with natural gas matters. These amounts included pipeline-related costs 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. Costs incurred for the nine months ended September 30, 2012 also included an increase in the accrual 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. There were no additional charges incurred during these periods related to penalties. (See "Natural Gas Matters" below.)

Future operating and maintenance expense will continue to be affected by costs associated with natural gas matters that are not recoverable through rates, including pipeline-related expenses incurred under the pipeline safety enhancement plan that are not authorized for recovery by the CPUC, 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, and ongoing legal and regulatory expenses related to these matters. (See "Natural Gas Matters" below.) The Utility also anticipates that it will incur additional costs in future periods as it undertakes a multi-year effort to clear some of its gas transmission pipeline easements of encroachments caused by vegetation overgrowth and building structures that could impede the Utility's access to pipelines. The additional costs incurred to clear encroachments may not be recoverable through rates.

Following the Utility's detection of mercury, a hazardous substance, in some gas transmission pipeline segments that have undergone hydrostatic pressure testing, the Utility has begun to assess the need for further remedial action to address the possible presence of mercury in other pipeline segments. The Utility is currently assessing the scope of the matter and the extent to which the Utility's future operating and maintenance costs may be affected is uncertain.

The Utility also forecasts that it will incur expenses in 2012 that are approximately $250 million higher than amounts assumed under the 2011 rate case decisions (including $176 million incurred during the nine months ended September 30, 2012, as described above) as the Utility works to improve the safety and reliability of its electric and natural gas operations. The Utility expects to continue to incur these incremental expenses in 2013.

Depreciation, Amortization, and Decommissioning

The Utility's depreciation and amortization expense consists of depreciation and amortization of 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 $51 million, or 9%, and by $159 million, or 10%, in the three and nine months ended September 30, 2012, respectively, as compared to the same periods in 2011. The increase in the three and nine months ended September 30, 2012 is primarily due to capital additions.

The Utility's depreciation expense for future periods is expected to be impacted as a result of capital additions and the implementation of new depreciation rates as authorized by the CPUC in future GRC and GT&S rate cases, and by the FERC TO rate cases.

Interest Income, Interest Expense and Other Income, Net

There were no material changes to interest income, interest expense and other income, net for the three and nine months ended September 30, 2012, as compared to the same periods in 2011.

Income Tax Provision

The Utility's income tax provision increased by $66 million, or 118%, in the three months ended September 30, 2012, as compared to the same period in 2011. The effective tax rates for the three months ended September 30, 2012 and 2011 were 26% and 22%, respectively. The effective tax rates increased in the three months ended September 30, 2012, as compared to the same period in 2011, mainly due to lower tax-deductible costs, including decommissioning and software development costs.

The Utility's income tax provision decreased by $48 million, or 13%, in the nine months ended September 30, 2012, as compared to the same period in 2011. The effective tax rates for the nine months ended September 30, 2012 and 2011 were 29% and 33%, respectively. The effective tax rates decreased in the nine months ended September 30, 2012, as compared to the same period in 2011, mainly due to receiving a benefit associated with a tax settlement for prior year tax returns, a higher tax deduction resulting from an accounting method change for repairs as compared to the same periods in 2011, and non-tax-deductible penalties recorded in 2011, with no comparable amount in 2012.

LIQUIDITY AND FINANCIAL RESOURCES

Overview

The Utility's ability to fund operations, make distributions to PG&E Corporation and preferred stockholders, and pay off maturing debt 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 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 and to fund its capital expenditures. The Utility relies on short-term debt, including commercial paper and draws under its revolving credit facility, 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, fund tax equity investments, 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.

Revolving Credit Facilities

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 September 30, 2012:

(in millions)	Termination Date	Facility Limit		Letters of Credit Outstanding	Borrowings	Commercial Paper		Facility Availability	
PG&E Corporation	May 2016	$300	(1)	$-	$-	$-		$300	
Utility	May 2016	3,000	(2)	330	-	145	(3)	2,525	(3)
Total revolving credit facilities		$3,300		$330	$-	$145		$2,825	

(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 the nine months ended September 30, 2012, there were no borrowings under PG&E Corporation's and the Utility's revolving credit facilities. For the nine months ended September 30, 2012, the average outstanding commercial paper balance was $879 million and the maximum outstanding balance during the period was $1.4 billion.

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. The $300 million 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 September 30, 2012, PG&E Corporation and the Utility were in compliance with all covenants under their respective revolving credit facilities.

2012 Financings

Utility

On April 2, 2012, the Utility repurchased the entire $50 million principal amount of pollution control bonds Series 2010 E that were subject to mandatory tender on that same date. The Utility will hold the bonds until they are remarketed to investors or retired.

On April 16, 2012, the Utility issued $400 million principal amount of 4.45% Senior Notes due April 15, 2042. The proceeds from the issuance were used to repay a portion of outstanding commercial paper and for general corporate purposes.

On August 16, 2012, the Utility issued $400 million principal amount of 2.45% Senior Notes due August 15, 2022 and $350 million principal amount of 3.75% Senior Notes due August 15, 2042. The proceeds were used to repay a portion of outstanding commercial paper and for general corporate purposes.

During the nine months ended September 30, 2012, the Utility received equity contributions of $715 million from PG&E Corporation to maintain the 52% equity component of the Utility's CPUC-authorized capital structure.

PG&E Corporation

During the nine months ended September 30, 2012, PG&E Corporation sold 5,446,760 shares of its common stock under the Equity Distribution Agreement executed in November 2011 for cash proceeds of $234 million, net of fees and commissions of $2 million. At September 30, 2012, PG&E Corporation had the ability to issue an additional $64 million of its common stock under the Equity Distribution Agreement. On March 20, 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 the nine months ended September 30, 2012, PG&E Corporation issued 5,446,542 shares of its common stock under its 401(k) plan, its Dividend Reinvestment and Stock Purchase Plan, and its share-based compensation plans for total cash proceeds of $214 million. PG&E Corporation used the cash proceeds for general corporate purposes and to contribute equity to the Utility.

Future Financing and Liquidity Needs

The amount and timing of the Utility's future financing and liquidity needs will depend on various factors, including:

- the amount of cash generated through normal business operations;
- the timing and amount of capital expenditures;
- the timing and amount of payments, including punitive damages, if any, made to third parties in connection with the San Bruno accident, and the timing and amount of related insurance recoveries (see "Natural Gas Matters –Third Party Claims" below);
- the timing and amount of penalties imposed on the Utility in connection with the investigations and enforcement matters pending against the Utility related to the San Bruno accident and the Utility's natural gas pipeline system (see "Natural Gas Matters – Pending CPUC Investigations and Enforcement Matters" below);
- the timing and amount of costs associated with the Utility's natural gas pipeline system, and the amount that is not recoverable through rates (see "Operating and Maintenance" above and "Natural Gas Matters" below);
- 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 9 of the Notes to the Condensed Consolidated Financial Statements);
- the amount of future tax payments; and
- the conditions in the capital and credit markets, and other factors.

As the Utility incurs charges that are not recoverable through customer rates, the Utility's equity financing needs will increase. PG&E Corporation contributes equity to the Utility as needed to maintain the Utility's CPUC-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.

A change in the Utility's authorized capital structure also may impact PG&E Corporation's and the Utility's future debt and equity financing needs. On April 20, 2012, the Utility filed an application to begin the cost of capital proceeding in which the CPUC will determine the Utility's authorized capital structure and rates of return beginning on January 1, 2013. (See "2013 Cost of Capital Proceeding" in "Regulatory Matters" below.)

Dividends

On September 18, 2012, the Board of Directors of PG&E Corporation declared a dividend of $0.455 per share, totaling $195 million, of which $190 million was paid on October 15, 2012 to shareholders of record on October 1, 2012. The remaining $5 million was reinvested under the Dividend Reinvestment and Stock Purchase Plan.

On September 18, 2012, the Board of Directors of the Utility declared dividends on its outstanding series of preferred stock, payable on November 15, 2012, to shareholders of record on October 31, 2012.

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 the nine months ended September 30, 2012 and 2011 were as follows:

	Nine Months Ended September 30,	
(in millions)	2012	2011
Net income	$798	$756
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	1,807	1,648
Allowance for equity funds used during construction	(79)	(64)
Deferred income taxes and tax credits, net	633	564
Other	189	193
Effect of changes in operating assets and liabilities:		
Accounts receivable	(327)	(125)
Inventories	(34)	(60)
Accounts payable	(31)	97
Income taxes receivable/payable	153	(156)
Other current assets and liabilities	15	(153)
Regulatory assets, liabilities, and balancing accounts, net	66	70
Other noncurrent assets and liabilities	315	491
Net cash provided by operating activities	$3,505	$3,261

In the nine months ended September 30, 2012, net cash provided by operating activities increased by $244 million compared to the same period in 2011 primarily due to fluctuations in activities within the normal course of business such as 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, including punitive damages, if any, that may be awarded, to third parties in connection with the San Bruno accident, any related insurance recoveries, any civil or criminal penalties that may be imposed on the Utility, higher operating and maintenance costs associated with the Utility's natural gas and electric operations, and future tax payments, 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, including the timing of regulatory approvals and 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 facilities.

The Utility's cash flows from investing activities for the nine months ended September 30, 2012 and 2011 were as follows:

	Nine Months Ended September 30,	
(in millions)	2012	2011
Capital expenditures	$ (3,361)	$ (2,968)
(Increase) decrease in restricted cash	(38)	170
Proceeds from sales and maturities of nuclear decommissioning trust investments	903	1,574
Purchases of nuclear decommissioning trust investments	(964)	(1,604)
Other	14	13
Net cash used in investing activities	$ (3,446)	$ (2,815)

Net cash used in investing activities increased by $631 million in the nine months ended September 30, 2012 compared to the same period in 2011. This increase was partially due to an increase of $393 million in capital expenditures in the nine months ended September 30, 2012. In addition, in the nine months ended September 30, 2011, there was a decrease of $170 million in restricted cash that primarily reflected $191 million in releases from escrow for settled or withdrawn Chapter 11 disputed claims, with no comparable activity in 2012.

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 the nine months ended September 30, 2012 and 2011 were as follows:

	Nine Months Ended September 30,	
(in millions)	2012	2011
Borrowings under revolving credit facilities	$ -	$ 208
Repayments under revolving credit facilities	-	(208)
Net (repayments) issuances of commercial paper, net of discount of $3 in 2012 and $2 in 2011	(1,247)	196
Proceeds from issuance of long-term debt, net of discount and issuance costs of $10 in 2012 and $6 in 2011	1,140	544
Long-term debt matured	(50)	(700)
Energy recovery bonds matured	(313)	(299)
Preferred stock dividends paid	(10)	(10)
Common stock dividends paid	(537)	(537)
Equity contribution	715	350
Other	25	12
Net cash used in financing activities	$ (277)	$ (444)

In the nine months ended September 30, 2012, net cash used in financing activities decreased by $167 million compared to the same period in 2011. Cash provided by or used in financing activities is driven by the level of cash provided by or used in operating and investing activities. The Utility generally utilizes equity contributions from PG&E Corporation and long-term senior unsecured debt issuances to maintain its CPUC-authorized capital structure and to fund its capital expenditures, and relies on short-term debt to fund temporary financing needs.

CONTRACTUAL COMMITMENTS

PG&E Corporation and the Utility enter into contractual commitments in connection with future obligations that relate to financing arrangements (such as long-term debt, preferred stock, and certain forms of regulatory financing), purchases of electricity and natural gas for customers, purchases of transportation capacity, purchases of renewable energy, and purchases of fuel and transportation to support the Utility's generation activities. (Refer to the 2011 Annual Report, the "Liquidity and Financial Resources" section above, and Notes 4 and 10 of the Notes to the Condensed Consolidated Financial Statements.)

CAPITAL EXPENDITURES

The Utility makes 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. The Utility collects additional revenue requirements to recover capital expenditures related to projects that have been specifically authorized by the CPUC in separate proceedings, such as for new power plants, the SmartMeterTM advanced metering infrastructure, or other initiatives.

Oakley Generation Facility

In March 2012, the California Court of Appeal granted The Utility Reform Network's ("TURN") appeal of the CPUC's decision in December 2010 that had approved the Utility's purchase of a 586-megawatt natural gas-fired facility in Oakley, California ("Oakley Generation Facility"). The Court determined that the CPUC had not allowed TURN, or other parties, sufficient opportunity to protest the Oakley Generation Facility, conduct discovery, or present evidence concerning the Utility's purchase and sale agreement. The facility is fully permitted and construction began in June 2011. On March 30, 2012, in response to the Court's ruling, the Utility filed a new application with the CPUC requesting approval of the Oakley Generation Facility and an amended and restated purchase and sale agreement between the Utility and Contra Costa Generating Station LLC. The Utility expects that the CPUC will issue a proposed decision on the application in late 2012.

Natural Gas Pipeline Safety Enhancement Plan

See "Natural Gas Matters – CPUC Gas Safety Rulemaking Proceeding" below.

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 incurred to improve the safety and reliability of the Utility's natural gas operations and to respond to the regulatory proceedings, investigations, and civil lawsuits related to the San Bruno accident and the Utility's natural gas operations. The current status of these matters and new developments are described below.

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 (the "Records OII"), (2) the Utility's operation of its natural gas transmission pipeline system in or near locations of higher population density (the "Class Location OII"), 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 (the "San Bruno OII"). During 2012, the CPSD issued investigative reports in each of these investigations alleging that the Utility committed numerous violations of applicable laws and regulations and recommending the CPUC impose penalties on the Utility. See "Penalties Conclusion" below. The CPUC began hearings on each of the investigations. (See Note 10 of the Notes to the Condensed Consolidated Financial Statements.) The CPUC will also consider testimony submitted by the CPSD in September 2012 that consisted of a financial analysis report prepared by a consultant engaged by the CPSD to examine PG&E Corporation's financial health and to provide an estimate of its ability to raise equity capital sufficient to fund a CPUC-imposed penalty on the Utility. The consultant concluded that PG&E Corporation could raise approximately $2.25 billion in addition to equity PG&E Corporation had already forecasted it would issue in 2012 to fund CPUC-imposed penalties on the Utility.

On October 11, 2012, the procedural schedule for evidentiary hearings and briefings in the three investigations as well as the submittal of the Utility's response on the financial resources issue was suspended until November 1, 2012 to enable the Utility, the CPSD, and other parties to continue to engage in negotiations to reach a stipulated outcome of these proceedings. Any settlement agreement that may be reached would be required to be submitted to the CPUC for its consideration. The CPUC would hold hearings before issuing a final decision. PG&E Corporation and the Utility are uncertain whether the parties will reach a settlement agreement and, if a settlement agreement is reached, whether the CPUC would approve it. See "Penalties Conclusion" below.

Other Natural Gas Compliance 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 utilities' natural gas operating practices. The CPSD has been delegated authority from the CPUC to enforce compliance with these regulations. As of September 30, 2012, the Utility has submitted 29 self-reports with the CPUC, plus additional follow-up reports. In a self-report filed on October 19, 2012, the Utility reported that it does not have documentation substantiating that approximately 4.5 miles of pipe had undergone integrity assessments prior to December 17, 2007, as required by federal regulations. In April 2012, the CPUC affirmed a $17 million penalty that had been imposed by the CPSD 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 completed all of the missed leak surveys.) The CPSD has not yet taken action with respect to the Utility's other self-reports. The CPSD 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 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 property easements and that the Utility plans to undertake a multi-year effort to clear these encroachments. (Also see "Operating and Maintenance" above.) PG&E Corporation and the Utility are uncertain how this matter will affect the investigative proceedings related to natural gas operations, or whether additional proceedings or investigations will be commenced by the CPUC.

Penalties Conclusion

The CPUC can impose significant penalties for violations of applicable laws, rules, and orders in connection with the pending investigations and enforcement matters described above. The CPUC and the CPSD have wide discretion to determine the number of violations and the length of time the violations existed. The calculation of penalties is generally based on the totality of the circumstances, including such factors as the severity of the violations; the type of harm caused by the violations and the number of persons affected; conduct taken to prevent, detect, disclose or rectify the violations; and the financial resources of the regulated entity.

PG&E Corporation and the Utility continue to believe it is probable that the Utility will incur total penalties of at least $200 million in connection with these investigations and other enforcement matters. PG&E Corporation and the Utility have not recorded any additional charges during the nine months ended September 30, 2012 and are unable to estimate the reasonably possible amount of penalties in excess of the amount accrued, and such amounts could be material. These estimates, and the assumptions on which they are based, are subject to change based on many factors, including developments that may occur during the settlement negotiations, the terms of any proposed settlement agreement that may be reached, whether and when the CPUC approves the proposed settlement agreement, and rulings and decisions by the CPUC and the administrative law judges presiding over these proceedings. Future changes in these estimates or assumptions 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. The CPUC is considering proposed implementation plans that were filed by the Utility and other California natural gas pipeline operators. As directed by the CPUC, the Utility also submitted proposed ratemaking mechanisms to allocate plan costs between ratepayers and shareholders. Several parties, including the CPUC's Division of Ratepayer Advocates ("DRA") and TURN, opposed various aspects of the Utility's proposals.

Pipeline Safety Enhancement Plan

On October 12, 2012, the CPUC administrative law judge ("ALJ") overseeing the proceeding issued a proposed decision regarding the Utility's proposed pipeline safety enhancement plan, cost forecasts, and ratemaking mechanisms. The Utility's proposed plan consists of two major programs, a pipeline modernization program (including valve automation) and a pipeline records integration program. The Utility has proposed to carry out the plan in two phases; the first phase began on January 1, 2011 and the second phase will begin on January 1, 2015. In its application, the Utility forecasted that its total plan-related costs over the first phase would be approximately $2.2 billion, including $1.4 billion in capital expenditures and $750 million in expenses. The Utility requested that the CPUC approve the scope and timing of projects proposed in the plan and authorize the Utility to recover its forecasted capital expenditures. The Utility proposed that most plan-related expenses incurred from 2012 through 2014 be recovered through rates but did not seek recovery of expenses for 2011 (forecasted to be $221 million).

In general, the ALJ recommended approval of the Utility's plan, but proposed to limit recovery of expenses to $167 million (plus two months of expenses in 2012 assuming an effective date of November 1, 2012) and to limit recovery of capital expenditures to $1.0 billion. Assuming a final decision is not issued until after December 31, 2012, the Utility would be unable to recover 2011 and 2012 expenses. Under the proposed decision, the Utility would be unable to recover any costs in excess of the adopted capital and expense amounts and the adopted amounts would be reduced by the cost of any plan project not completed and not replaced with a higher priority project. In addition, the ALJ recommended that the Utility's ROE for plan-related capital investments through 2014 be reduced to the cost of debt (currently 6.05%) for the first five years the investments are in service, which the Utility currently estimates would reduce net income over the relevant period by approximately $130 million. See "2013 Cost of Capital Proceeding" below.

The following table compares the Utility's requested expense and capital amounts with the ALJ's recommended amounts and shows the total estimated reduction in equity earnings over the relevant period based on the ALJ's ROE recommendation:

(in millions)	2011		2012		2013	2014	Total
Expense							
Requested	$221		$231		$155	$144	$751
ALJ's recommendation	-	(1)	-	(2)	74	93	167
Difference	$221		$231		$81	$51	$584
Capital							
Requested	$69		$384		$480	$500	$1,433
ALJ's recommendation	47		265		353	367	1,032
Difference	$22		$119		$127	$133	$401
ROE (3)							$130

(1) The Utility's August 2011 application did not request recovery of forecast 2011 plan-related expenses of $221 million.
(2) The ALJ assumed a November 1, 2012 effective date, but the table above assumes a delayed effective date resulting in no recovery of 2012 expenses.
(3) Estimated total after-tax reduction in equity earnings based on ALJ's recommended rate of ROE and recommended lower capital amounts over the relevant period, as compared to the 11% rate requested in the Utility's pending cost of capital proceeding.

The ALJ stated that if the proposed decision is adopted by the CPUC, the ratemaking recovery authorized in the rulemaking decision would 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.) Comments on the proposed decision are due on November 13, 2012; reply comments are due on November 26, 2012.

The Utility forecasts that total unrecoverable pipeline-related expenses for 2012 could be as much as $550 million, including $371 million incurred in the nine months ended September 30, 2012 to validate safe pipeline operating pressures and conduct strength testing, as well as legal and other expenses related to natural gas matters. At September 30, 2012, PG&E Corporation and the Utility had capitalized approximately $187 million of plan-related expenditures in their Condensed Consolidated Balance Sheets. If the proposed decision is adopted by the CPUC, disallowed capital investments will be charged to net income in the period in which the CPUC orders such a disallowance. Future disallowed expense and capital costs would be charged to net income in the period incurred.

The ultimate amount of pipeline-related costs that the Utility will be allowed to recover from customers will be affected by various factors, including the terms of the CPUC's final decision on the Utility's plan, the outcome of the CPUC's pending investigations discussed above, including the terms of a potential settlement, if any, that may be reached in the pending CPUC investigations. PG&E Corporation's and the Utility's financial results also will be impacted by additional costs the Utility will incur to address any other pipeline matters identified by the Utility or to comply with new regulatory or legislative requirements.

Gas Safety Plan

On June 29, 2012, the Utility filed its proposed gas safety plan with the CPUC to comply with recently enacted California law ("Senate Bill 705") that requires each California gas corporation to implement industry best practices for both natural gas transmission and distribution. In the plan, the Utility outlined the safety programs the Utility has in place, those that are being implemented, and future projects and initiatives to increase the safety and reliability of the Utility's gas system, including the extensive work proposed in the Utility's pipeline safety enhancement plan. The plan includes a proposed timeline for implementing the proposed projects and initiatives that corresponds to future rate case proceedings, such as the 2014 GRC and the 2015 GT&S rate case. (See "2014 General Rate Case" below.) The CPUC is required to accept, modify, or reject the gas safety plan by the end of 2012.

The CPUC also ordered that CPSD-managed management and financial audits of each gas corporation be conducted to address safety-related corporate culture and historical spending. The financial audits will examine the gas corporations' authorized and budgeted safety-related capital investments and operation and maintenance expenditures for their last two authorized GRC cycles. (The CPUC stated that the Utility's natural gas transmission-related expenditures will be excluded from the financial audit since its transmission-related expenditures were already the subject of an audit.) The ALJ has not yet issued an order to establish the scope and timing of the management and financial audits and the Utility is uncertain when the audits will be completed and what action the CPUC may take in response to the results of the audits.

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.

Third-Party Claims

In addition to the investigations and proceedings discussed above, at September 30, 2012, approximately 130 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 420 plaintiffs. The lawsuits seek compensation for personal injury and property damage, and other relief, including punitive damages. These cases have been coordinated and assigned to one judge in the San Mateo County Superior Court. As of October 26, 2012, approximately 70 plaintiffs have settled their claims. The trial date for the first group of the remaining plaintiffs is currently scheduled for January 2, 2013. PG&E Corporation and the Utility have filed a motion to dismiss the remaining plaintiffs' claims for punitive damages based upon a lack of evidence to support such claims. The court has set a hearing date for October 29, 2012 to consider the motion.

At September 30, 2012, the Utility has recorded a cumulative charge of $455 million for estimated third-party claims related to the San Bruno accident, including an $80 million charge made during the second quarter of 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 10 to the Condensed Consolidated Financial Statements.)

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 this insurance coverage is approximately $992 million in excess of a $10 million deductible. At September 30, 2012, the Utility has recognized cumulative insurance recoveries of $234 million, including $99 million and $135 million during the three and nine months ended September 30, 2012. Although the Utility believes that a significant portion of costs incurred for third-party claims related to the San Bruno accident will ultimately be recovered through its insurance, it is unable to predict the amount and timing of future insurance recoveries. (See Note 10 to the Condensed 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 CPSD's January 2012 investigative report 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 CPSD recommended that the Utility should use such amounts to fund future gas transmission expenditures and operations. (See 2011 Annual Report.) 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. On October 9, 2012, PG&E Corporation and the Utility requested the court to 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 have requested that the court order the plaintiffs to delay proceeding on the complaint until the CPUC investigations described above are concluded. The court has set a hearing for December 17, 2012. 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 Claims

A purported shareholder derivative lawsuit was filed 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. On May 26, 2011, the judge ordered that proceedings in the derivative lawsuit be delayed until further order of the court.

In February 2011, the Board authorized PG&E Corporation to reject a shareholder demand that the Board (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 members, officers, other employees, and third parties; and (3) adopt corporate governance initiatives and safety programs. The Board also reserved the right to commence further investigation or litigation regarding the San Bruno accident if the Board 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. Significant regulatory developments that have occurred since the 2011 Annual Report was filed with the Securities and Exchange Commission ("SEC") are discussed below.

2014 General Rate Case

In the Utility's 2014 GRC, the CPUC will determine the annual amount of authorized revenue requirements that the Utility is authorized to collect from customers beginning January 1, 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. During the GRC period, the Utility plans to make additional capital investments in electric and natural gas distribution and electric generation infrastructure, and improve safety, reliability and customer service.

Under the process established by the CPUC for general rate cases, the Utility is required to submit a draft of its GRC application to the DRA for review. On July 2, 2012, the Utility submitted its draft application to the DRA, which included the Utility's calculations supporting the amount of its proposed increase in revenue requirements for the GRC period. On September 14, 2012, the DRA notified the Utility that it had completed its review and that the Utility was authorized to file its formal application with the CPUC after the expiration of a 60-day waiting period. The Utility anticipates that it will file its formal application with the CPUC, including revised calculations supporting the final amount of its requested revenue requirement increase, before the end of 2012.

Independent consultants hired by the CPUC's CPSD are expected to review 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 consultants are expected to evaluate the Utility's plans, provide information about the quality and cost-effectiveness of the Utility's safety and security proposals, and compare the proposals to industry best practices and standards. The Utility will be able to respond to the consultants' reviews later in the proceeding, and the Utility's response may include a revised revenue requirement forecast to address specific recommendations made by the consultants.

Other parties, including the DRA and TURN, will have an opportunity to file comments on the Utility's application. Following the submission of comments and public hearings, the assigned CPUC ALJ would issue a proposed decision for consideration by the CPUC. The Utility intends to request that the CPUC issue a final decision by December 31, 2013.

Electric Transmission Owner Rate Case

On September 28, 2012, the Utility filed an application with the FERC requesting an increase in retail and wholesale electric transmission rates charged to customers to recover the Utility's costs to provide electric transmission services. The Utility's present rates have been in effect since March 1, 2011. The Utility has requested the FERC to authorize an estimated 2013 annual revenue requirement of $1.2 billion, an increase of $254 million over the estimated revenues that the Utility would receive in 2013 based on present rates. This includes a requested return on equity of 11.5%.

The most significant factors driving the requested increase are the Utility's continuing needs to replace and modernize aging 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, compared to $152 million in 2011.

The Utility requested that the new rates become effective on December 1, 2012. In accordance with past practice, the Utility expects that the FERC will issue an order accepting the requested increase and allowing the proposed rate changes to become effective on May 1, 2013, subject to refund following the FERC's issuance of a final decision on the application.

2013 Cost of Capital Proceeding

On April 20, 2012, the Utility filed an application with the CPUC to request that the CPUC authorize the Utility's capital structure and the rates of return on each capital structure component, for the Utility's electric generation, electric and natural gas distribution, and natural gas transmission and storage rate base beginning on January 1, 2013. (The FERC has jurisdiction over the rates of return for the Utility's electric transmission rate base.) The following table compares the currently authorized capital structure and rates of return that will remain in effect through 2012 with those requested in the Utility's application:

	Currently Authorized			Requested		
	Cost	Capital Structure	Weighted Cost	Cost(1)	Capital Structure	Weighted Cost
Long-term debt	6.05 %	46 %	2.78 %	5.69 %	47 %	2.67 %
Preferred stock	5.68 %	2 %	0.11 %	5.60 %	1 %	0.06 %
Return on common equity	11.35 %	52 %	5.90 %	11.00 %	52 %	5.72 %

Overall Rate of Return	8.79	%	8.45	%

(1) In October 2012, the Utility filed an updated application with the CPUC to update its requested costs of long-term debt from 5.69% to 5.52%

The Utility also has requested that the CPUC approve the continuation of the annual cost of capital adjustment mechanism that has been in effect since 2008. The mechanism would be triggered in a particular year if the 12-month October-through-September average of the applicable Moody's Investors Service utility bond index increases or decreases by more than 100 basis points from the benchmark. If the adjustment mechanism is triggered, the Utility’s authorized ROE beginning on the next January 1st would be adjusted by one-half of the increase or decrease. In addition, the Utility’s authorized long-term debt and preferred stock costs would be updated to reflect actual August month-end embedded costs and forecasted interest rates for variable long-term debt and new long-term debt and preferred stock scheduled to be issued in the coming year. In any year where the 12-month average yield triggers an automatic ROE adjustment, that average yield would become the new benchmark.

The CPUC split the proceeding into two phases with the first phase addressing test year 2013 cost of capital issues and the second phase addressing the cost of capital adjustment mechanism. The CPUC recently concluded evidentiary hearings on the first phase of the proceeding and is expected to issue a final decision before the end of 2012. The Utility has proposed that any changes to its revenue requirements resulting from the CPUC's cost of capital decision be effective January 1, 2013. (The Utility estimates that its 2013 revenue requirement associated with the requested cost of capital would be approximately $100 million less than the currently authorized revenue requirement.)

Evidentiary hearings for the second phase are scheduled for January 2013 with a final decision expected in the second quarter of 2013. The Utility has proposed to file its next full cost of capital application with the CPUC in April 2015 for test year 2016.

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 nuclear facilities in Japan. The NRC also requested nuclear power plant owners to provide additional information about seismic and flooding hazards and emergency preparedness, which the NRC may consider in future regulatory proceedings or actions. As applied to the Utility, the NRC's March 12, 2012 orders require the Utility to develop mitigation strategies to respond to potential extreme natural events resulting in the loss of power at Diablo Canyon and to enhance the instrumentation used in the plant's spent fuel pool to better monitor water temperature. The Utility, as well as other nuclear power plant owners, are required to submit an integrated plan, including a description of how compliance with the orders will be achieved, to the NRC by February 2013. After reviewing the plans, the NRC plans to issue facility-specific orders, as necessary, imposing license conditions that address the requirements of the orders. 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 NRC operating licenses for the two generation units at Diablo Canyon include various license conditions related to seismic design and safety that were based on seismic information and studies that were used to develop the seismic qualification basis for plant structures, systems, and components at Diablo Canyon. In January 2011, the Utility provided updated information to the NRC about seismological information about a newly discovered earthquake fault called the Shoreline fault. In the report, the Utility concluded that the seismic risks associated with the Shoreline fault were within the existing design basis of the current operating licenses. On October 12, 2012, the NRC notified the Utility that the NRC agreed with the Utility's seismic analysis. The NRC also noted that the Utility was conducting offshore and onshore two-and three-dimensional seismic studies and stated that if, during the collection of the data, new faults are discovered or information is uncovered that would suggest the Shoreline fault is more capable than currently believed, the staff expects that the Utility will provide the NRC with an interim evaluation that describes actions taken or planned to address the higher seismic hazard relative to the design basis, as appropriate, as part of the evaluations requested in the NRC staff's March 12, 2012 request for information. The NRC also stated that changes to the licensing basis may be appropriate to capture the information developed in response to the March 12, 2012 request for information. The Utility expects that the seismic studies will not be completed until 2013 or 2014.

The NRC's operating license for Diablo Canyon Unit 1 expires in November 2024 and the operating license for Unit 2 expires in August 2025. The Utility has filed an application at the NRC seeking renewal of the licenses, a process that is expected to take several years. (At the Utility's request, the NRC has agreed to delay processing the Utility's pending license renewal application until the Utility completes the seismic studies discussed above.) On August 7, 2012, the NRC ruled that it will not issue final decisions in licensing or re-licensing proceedings, including the Utility's application, until it has reconsidered the environmental impacts of the temporary and permanent storage of spent nuclear fuel to comply with the National Environmental Policy Act ("NEPA"). The NRC issued its order in response to a federal appellate court's ruling issued in June 2012 that found that the NRC had failed to comply with the NEPA before issuing its "waste confidence decision" in which the NRC determined that spent nuclear fuel can be safely managed until a permanent off-site repository is established. In its August 2012 ruling, 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, develop an environmental impact statement to support the rulemaking, and refrain from site-specific review of waste-confidence issues except in rare circumstances. (See Item 1.A. Risk Factors, below.)

In September 2012, the CPUC granted the Utility's request for authority to recover an additional $47 million in rates to conduct the seismic studies discussed above. Actual costs of the seismic studies may differ from estimates depending on the procurement process, environmental permitting processes, and required environmental monitoring and mitigation. The Utility expects that it will incur additional costs to comply with the NRC's March 12, 2012 order to implement new requirements the NRC may adopt after it reviews the information submitted in response to the NRC's March 12, 2012 request for information. Although the Utility intends to request CPUC approval to recover estimated compliance costs as part of the 2014 GRC funding request, the Utility's forecast may be insufficient or the CPUC may not fully approve recovery of such costs in rates.

Other Matters

Electric Distribution Facilities

The Utility has been conducting a system-wide review of its maintenance plans for underground and overhead electric distribution facilities after the Utility reported to the CPUC in July 2012 that the Utility had determined, based on a review of its maintenance plans and distribution maps, that some of its facilities in one of its divisions were not patrolled and inspected at the periodic intervals required by the CPUC's rules. As of October 25, 2012, preliminary data indicated that approximately 0.4% of the Utility's total electric distribution facilities are not included in maintenance plans and were not patrolled or inspected at the intervals required by CPUC rules. The Utility plans to submit the results of its system-wide assessment to the CPSD, along with the Utility's plan for completing the inspections and performing any remedial work that may be identified.

The Utility has also reported to CPSD that it planned to re-inspect electric distribution underground and overhead facilities that had been identified as inspected by a contractor after the Utility performed a sampling of the contractor's inspections of electric underground facilities and determined that the inspection practices used by some of the contractor's employees did not meet the Utility's quality standards for installation of verification tags.

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 fines or penalties on the Utility.

Electric 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" in the 2011 Annual Report.) 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. Significant developments that have occurred since the 2011 Annual Report was filed with the SEC are discussed below.

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 and Topock, Arizona. 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.

In June 2012, the Regional Board issued an amended cleanup and abatement order to allow the Utility to implement a voluntary whole house water replacement program for approximately 300 resident households located within or near the chromium plume boundary. Eligible residents were given until October 15, 2012 to decide whether to accept a replacement water supply or have the Utility purchase their properties, or alternatively not participate in the program. The majority of eligible residents opted to accept the Utility's offer to purchase their property. 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.

In August 2012, the Regional Board issued a draft environmental impact report ("EIR") that evaluated several alternatives for remediating groundwater contamination using a combination of different remedial methods, including using pumped groundwater from extraction wells to irrigate agricultural land and in-situ treatment of the contaminated water. The Utility expects that the Regional Board will consider certification of the final EIR in 2013.

At September 30, 2012, $227 million was accrued in PG&E Corporation's and the Utility's Condensed Consolidated Balance Sheets for estimated undiscounted future remediation costs associated with the Hinkley natural gas compressor site, compared to $149 million accrued at December 31, 2011. The increase primarily reflects the Utility's best estimate of costs associated with providing water replacement systems to eligible residents or purchasing property from eligible residents, as described above. Remediation costs for the Hinkley natural gas compressor site are not recovered from customers.

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, estimates and assumptions regarding the amount of liability incurred may be subject to further changes. Future changes in estimates may have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

Topock Site

The Utility's remediation and abatement efforts at the Topock site are subject to the regulatory authority of the California 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 plans to submit its intermediate design plan to the DTSC and the DOI in January 2013 and a final plan for approval in late 2013. 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 September 30, 2012, $236 million was accrued in PG&E Corporation's and the Utility's Condensed Consolidated Balance Sheets for estimated undiscounted future remediation costs associated with the Topock site, compared to $218 million accrued at December 31, 2011. 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, estimates and assumptions regarding the amount of liability incurred may be subject to change. The Utility expects to recover 90% of its remediation costs for the Topock site from customers. Future changes in estimates could have a material impact on PG&E Corporation's and the Utility's future financial condition.

Greenhouse Gas Regulation

California Assembly Bill 32 requires the gradual reduction of statewide GHG emissions to the 1990 level by 2020. The California Air Resources Board ("CARB") has approved various regulations, including regulations to establish 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. The cap-and-trade compliance period will begin on January 1, 2013. The CARB has allocated a fixed number of emission allowances (i.e., the rights to emit GHGs) to regulated electric distribution utilities, such as the Utility. The Utility is required to consign allocated emission allowances into periodic auctions, the first of which is scheduled to be held on November 14, 2012. All proceeds received from auction participants, as well as the Utility's compliance costs under the cap-and-trade program, are expected to be passed through to customers through rates.

Under the CARB's regulations, emitters (also known as covered entities) also can purchase "offset credits" from certified parties that develop environmental projects in sectors not regulated under the cap, such as reforestation and methane capture projects. Emitters would be able to use the offset credits to satisfy up to 8% of their compliance obligations. In March 2012, a lawsuit was filed in the San Francisco Superior Court challenging the CARB's regulations pertaining to offset credits. Evidentiary hearings are scheduled for November 2012, but it is currently uncertain when this challenge will be resolved and how its resolution will affect implementation of the CARB's cap-and-trade program.

Renewable Energy Resources

California's new Renewables Portfolio Standard ("RPS") program increases the amount of renewable energy that load-serving entities ("LSE"s), 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 new RPS program, which became effective in December 2011, established three initial compliance periods: 2011 through 2013, 2014 through 2016, and 2017 through 2020. The RPS compliance requirement that must be met for each of these compliance periods will gradually increase through 2020 and will be 33% on an annual basis thereafter.

In June 2012, the CPUC adopted rules for transitioning between the prior 20% RPS program and the new 33% RPS program, applying excess procurement quantities across compliance periods, using procurement from short-term contracts to meet compliance requirements, and reporting RPS compliance annually to the CPUC. In future decisions, the CPUC is expected to address the process for seeking a reduction or waiver of compliance obligations. The CPUC is also expected to determine whether to change the penalty provisions applicable to the former RPS program, which had generally established a maximum penalty of $25 million per year on each retail seller that had an unexcused failure to meet its compliance obligation.

The Utility has made substantial financial commitments under third-party renewable energy contracts to meet RPS procurement quantity requirements. (See Note 10 of the Notes to the Condensed 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 U.S. Environmental Protection Agency ("EPA") published draft regulations in April 2011 to implement the requirements of the federal Clean Water Act which requires that 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.

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 10 (the Utility's commodity purchase agreements) of the Notes to the Condensed Consolidated Financial Statements.

CONTINGENCIES

In addition to the contingencies described under "Natural Gas Matters" above, PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to Chapter 11 disputed claims, guarantees, regulatory proceedings, nuclear operations, legal matters, environmental compliance and remediation, and tax matters. (See Notes 9 and 10 of the Notes to the Condensed Consolidated Financial Statements.)

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; 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 derivatives 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 derivatives. 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. PG&E Corporation and the Utility are implementing programs to comply with final regulations that have been issued and continue to monitor draft regulations, including evaluation of potential impacts on the Utility's procurement activities and risk management programs.

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 but 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 at September 30, 2012. The Utility's approximate high, low, and average values-at-risk during the 12 months ended September 30, 2012 were $13 million, $10 million, and $11 million, respectively. (See Note 7 of the Notes to the Condensed 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 September 30, 2012, 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 $6 million, 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 September 30, 2012 and December 31, 2011:

(in millions)	September 30, 2012	December 31, 2011
Gross credit exposure before credit collateral(1)	$127	$151
Credit collateral	(10)	(13)
Net credit exposure(2)	$117	$138
Number of wholesale customers or counterparties >10%	2	2
Net credit exposure to wholesale customers or counterparties >10%	$78	$106

(1) Gross credit exposure equals mark-to-market value on physically and financially settled contracts, notes receivable, 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 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 the Condensed Consolidated Financial Statements in accordance with U.S. generally accepted accounting principles involved the use of estimates and assumptions that affect the recorded amounts of assets and liabilities as of the date of the Condensed Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. PG&E Corporation and the Utility consider their accounting policies for regulatory assets and liabilities, loss contingencies associated with environmental remediation liabilities and legal and regulatory matters, asset retirement obligations, and pension and other postretirement benefit plans to be critical accounting policies due, in part, to these accounting policies' complexity, relevance and materiality to the financial position and results of operations of PG&E Corporation and the Utility, and requirement to use material judgments and estimates. Actual results may differ substantially from these estimates. These accounting policies and their key characteristics are discussed in detail in the 2011 Annual Report.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PG&E Corporation's and the Utility's primary market risk results from changes in energy commodity prices. PG&E Corporation and the Utility engage in price risk management activities for non-trading purposes only. Both PG&E Corporation and the Utility may engage in these price risk management activities using forward contracts, futures, options, and swaps to hedge the impact of market fluctuations on energy commodity prices and interest rates. (See the section above entitled "Risk Management Activities" in Item 2: Management's Discussion and Analysis of Financial Condition and Results of Operations.)

ITEM 4. CONTROLS AND PROCEDURES

Based on an evaluation of PG&E Corporation's and the Utility's disclosure controls and procedures as of September 30, 2012, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures were effective to ensure that information required to be disclosed by PG&E Corporation and the Utility in reports that the companies file or submit under the Securities Exchange Act of 1934 ("1934 Act") is recorded, processed, summarized, and reported within the time periods specified in the SEC rules and forms. In addition, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures were effective in ensuring that information required to be disclosed by PG&E Corporation and the Utility in the reports that PG&E Corporation and the Utility file or submit under the 1934 Act is accumulated and communicated to PG&E Corporation's and the Utility's management, including PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

There were no changes in internal control over financial reporting that occurred during the quarter ended September 30, 2012 that have materially affected, or are reasonably likely to materially affect, PG&E Corporation's or the Utility's internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

In addition to the following legal proceedings, PG&E Corporation and the Utility are involved in various legal proceedings in the ordinary course of their business. For more information regarding PG&E Corporation's and the Utility's contingencies, see Note 10 of the Notes to the Condensed Consolidated Financial Statements.

Diablo Canyon Power Plant

The EPA published draft regulations in April 2011 to implement the requirements of the federal Clean Water Act, which requires that 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 must issue final regulations by July 2013.

The EPA's final regulations could affect future negotiations between the Central Coast Regional Water Quality Control Board and the Utility regarding the status of the 2003 settlement agreement.

For more information regarding the status of the 2003 settlement agreement between the Central Coast Regional Water Quality Control Board and the Utility, see "Part I, Item 3. Legal Proceedings" in the 2011 Annual Report.

Hinkley Natural Gas Compressor Site

For more information regarding the resolution of this matter, see "Part I, Item 3. Legal Proceedings" in the 2011 Annual Report and "Part II, Item 1. Legal Proceedings" in PG&E Corporation's and the Utility's combined Quarterly Report on Form 10-Q for the quarters ended March 31, 2012 and June 30, 2012.

For more information about the Utility's remediation activities at the Hinkley natural gas compressor site, see the section entitled "Environmental Matters" above in Item 2: Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 10 of the Notes to the Condensed Consolidated Financial Statements.

Litigation Related to the San Bruno Accident and Natural Gas Spending

Various lawsuits have been filed against PG&E Corporation and the Utility in connection with the San Bruno accident. The lawsuits seek compensation for personal injury and property damage, and other relief, including punitive damages. A purported shareholder derivative lawsuit was filed 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. All of these cases have been coordinated and assigned to one judge in the San Mateo County Superior Court. On May 26, 2011, the judge ordered that proceedings in the derivative lawsuit be delayed until further order of the court. For additional information, see the section entitled "Natural Gas Matters – Third-Party Claims" above in Item 2: Management's Discussion and Analysis of Financial Condition and Results of Operations and in Note 10 of the Notes to the Condensed Consolidated Financial Statements.

In addition, on August 23, 2012, a complaint was filed in the San Francisco Superior Court against PG&E Corporation and the Utility (and other unnamed defendants) by individuals who seek certification of a class consisting of all California residents who were customers of the Utility between 1997 and 2010, with certain exceptions. The plaintiffs allege that the Utility collected more than $100 million in customer rates from 1997 through 2010 for the purpose of various safety measures and operations projects but instead used the funds for general corporate purposes such as executive compensation and bonuses. PG&E Corporation and the Utility contest the allegations. For additional information, see the section entitled "Natural Gas Matters – Class Action Complaint" above in Item 2: Management's Discussion and Analysis of Financial Condition and Results of Operations and in Note 10 of the Notes to the Condensed Consolidated Financial Statements.

Pending CPUC Investigations and Enforcement Matters

The CPUC is conducting three investigations pertaining to the Utility's natural gas operations, including an investigation of the San Bruno accident. In 2012, the CPSD issued investigative 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 Utility. The CPUC began hearings in each of the investigations. The CPUC is also considering testimony submitted by the CPSD in September 2012 that consisted of a financial analysis report prepared by a consultant engaged by the CPSD to examine PG&E Corporation's financial health and to provide an estimate of its ability to raise equity capital sufficient to fund a CPUC-imposed penalty on the Utility.

On October 11, 2012, procedural schedule for evidentiary hearings and briefings in the three investigations, as well as the submittal of the Utility's response to the CPSD's financial resources testimony were suspended until November 1, 2012 to enable the CPSD, the Utility, and other parties to continue to engage in negotiations to reach a stipulated outcome of these proceedings. Any settlement agreement that may be reached would be submitted to the CPUC for its consideration. The CPUC would hold public hearings before issuing a final decision. PG&E Corporation and the Utility are uncertain whether the parties will reach a settlement agreement and, if a settlement agreement is reached, whether the CPUC would approve it.

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 utilities' natural gas operating practices. The CPUC delegated authority to the CPSD to enforce compliance with these regulations. As of September 30, 2012, the Utility has submitted 29 self-reports with the CPUC plus additional follow-up reports. In a self-report filed on October 19, 2012, the Utility reported that it does not have documentation substantiating that approximately 4.5 miles of pipe had undergone integrity assessments prior to December 17, 2007, as required by federal regulations. In April 2012, the CPUC affirmed a $17 million penalty that had been imposed by the CPSD based on the Utility's self-report in which the Utility failed to conduct periodic leak surveys because it had not included 16 gas distribution maps in its leak survey schedule. (The Utility has completed all of the missed leak surveys.) The CPSD has not yet taken action with respect to the Utility's other self-reports. The CPSD may issue additional citations and impose penalties on the Utility associated with these or future reports that the Utility may file.

For additional information, see the section entitled "Natural Gas Matters – Pending CPUC Investigations and Enforcement Matters" above in Item 2: Management's Discussion and Analysis of Financial Condition and Results of Operations and in Note 10 of the Notes to the Condensed Consolidated Financial Statements.

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.

See the section entitled "Natural Gas Matters – Criminal Investigation" above in Item 2: Management's Discussion and Analysis of Financial Condition and Results of Operations and in Note 10 of the Notes to the Condensed Consolidated Financial Statements.

ITEM 1A. RISK FACTORS

For information about the significant risks that could affect PG&E Corporation's and the Utility's future financial condition, results of operations, and cash flows, see the section of the 2011 Annual Report entitled "Risk Factors," as supplemented below, and the section of this quarterly report entitled "Cautionary Language Regarding Forward-Looking Statements."

CPUC Pending Investigations and Rulemaking Proceeding Related to Natural Gas Matters, Litigation Arising from the San Bruno Accident

As discussed above in the section entitled "Natural Gas Matters – Pending CPUC Investigations and Enforcement Matters," in Item 2: Management's Discussion and Analysis of Financial Condition and Results of Operations, the CPUC is conducting three investigations pertaining to the Utility's natural gas operations, including an investigation of the San Bruno accident. (For more information, see Note 10 of the Notes to the Condensed Consolidated Financial

Statements.) In 2012, the CPSD 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 Utility and began hearings in each of the investigations. The CPUC is also considering testimony submitted by the CPSD in September 2012 that consisted of a financial analysis report prepared by a consultant engaged by the CPSD to examine PG&E Corporation's financial health and to provide an estimate of its ability to raise equity capital sufficient to fund a CPUC-imposed penalty on the Utility. The consultant concluded that PG&E Corporation could raise approximately $2.25 billion in addition to equity PG&E Corporation had already forecasted it would issue in 2012 to fund CPUC imposed penalties on the Utility.

On October 11, 2012, the procedural schedules for evidentiary hearings and briefings in the three investigations, as well as the submittal of the Utility's response on the financial resources issue, were suspended until November 1, 2012, to enable the CPSD, the Utility, and other parties to continue to engage in negotiations to reach a stipulated outcome of these investigations. Any settlement agreement that may be reached would be subject to CPUC approval. The CPUC would hold public hearings to consider comments and objections to the proposed stipulated outcome before issuing a final decision. Even if the CPUC approves a stipulated outcome, implementation could be delayed pending the resolution of appeals or applications for rehearing that may be filed after a final decision is issued.

PG&E Corporation and the Utility continue to believe it is probable that the CPUC will impose total penalties of at least $200 million on the Utility with these investigations and other enforcement matters relating to self-reports the Utility has filed regarding its compliance with regulations related to the safety of natural gas facilities and natural gas operating practices. They are unable to estimate the reasonably possible amount of penalties in excess of this amount and such amounts could be material.

These estimates, and the assumptions on which they are based, are subject to change based on many factors, including developments that may occur during the settlement negotiations, the terms of a proposed settlement agreement that may be reached, whether and when the CPUC approves the proposed settlement agreement, and rulings and decisions by the CPUC and the administrative law judges presiding over these proceedings. Future changes in these estimates or assumptions could have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows. Further, the CPSD may issue additional citations and impose penalties on the Utility in connection with other self-reports the Utility has filed, or may file in the future, regarding its compliance with natural gas regulations. In addition, on October 12, 2012, a proposed decision was issued that, if adopted by the CPUC, would deny the Utility's request to recover a material amount of the costs the Utility has incurred, and forecasts that it will incur through 2014, to perform work under the pipeline safety enhancement plan. Assuming a final decision is not issued until after December 31, 2012, the Utility would be unable to recover 2011 and 2012 expenses. The proposed decision also recommends that the authorized rate of ROE on authorized capital expenditures made under the plan be reduced for five years. (See "Natural Gas Matters−CPUC Gas Safety Rulemaking Proceeding" and "Results of Operations−Operating and Maintenance Expenses" in Item 2: Management's Discussion and Analysis of Financial Condition and Results of Operations.") The ultimate amount of unrecoverable pipeline-related costs the Utility incurs will depend on many factors, including the terms of the CPUC's final decision and the extent to which actual costs incurred under the plan exceed authorized amounts.

Future developments in the pending litigation and criminal investigation arising from the San Bruno accident also could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows. (See the sections entitled "Criminal Investigation," "Third-Party Claims," and "Class Action Complaint" under the heading "Natural Gas Matters" in Item 2: Management's Discussion and Analysis of Financial Condition and Results of Operations.)

Diablo Canyon

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 nuclear facilities in Japan. The NRC has also requested nuclear power plant owners to provide additional information about seismic and flooding hazards and emergency preparedness, which the NRC may consider in future regulatory proceedings or actions. As applied to the Utility, the orders require the Utility to re-evaluate the seismic hazards at Diablo Canyon and develop mitigation strategies to respond to potential extreme natural events resulting in the loss of power at Diablo Canyon and to enhance the instrumentation used in the plant's spent fuel pool to better monitor water temperature. The Utility, as well as other nuclear power plant owners, are required to submit an integrated plan, including a description of how compliance with the orders will be achieved, to the NRC by February 2013. After reviewing the plans, the NRC plans to issue facility-specific orders, as necessary, imposing license conditions that address the requirements of the orders. 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 requested that the NRC renew the operating licenses for the two units at Diablo Canyon. The NRC's operating license for Diablo Canyon Unit 1 expires in November 2024 and the operating license for Unit 2 expires in August 2025. At the Utility's request, the NRC has agreed to delay processing the Utility's pending license renewal application until the Utility completes extensive seismic studies of onshore and offshore areas surrounding Diablo

Canyon. The Utility also will submit new data collected from the seismic studies to the NRC pursuant to the NRC's March 12, 2012 request. The Utility expects that the seismic studies will not be completed until 2013 or 2014.

On August 7, 2012, the NRC ruled that it will not issue final decisions in licensing or re-licensing proceedings, including the Utility's application, until it has reconsidered the environmental impacts of the temporary and permanent storage of spent nuclear fuel to comply with the National Environmental Policy Act ("NEPA"). The NRC issued its order in response to a federal appellate court's ruling issued in June 2012 that found that the NRC had failed to comply with the NEPA before issuing its "waste confidence decision" in which the NRC determined that spent nuclear fuel can be safely managed until a permanent off-site repository is established. In its August 2012 ruling, 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, develop an environmental impact statement to support the rulemaking, and refrain from site-specific review of waste-confidence issues except in rare circumstances.

The Utility expects that it will incur additional costs to comply with the NRC's March 12, 2012 order. The Utility also may incur costs to comply with new requirements the NRC may adopt after it reviews the information submitted in response to the NRC's March 12, 2012 request for information. Further, the new waste confidence decision and temporary storage rule may require the Utility to incur additional costs in order to obtain NRC approval of the Utility's re-licensing application. The CPUC may not authorize the Utility to recover all of its compliance costs.

PG&E Corporation and the Utility are unable to predict whether the Utility will be able to comply with new requirements or new seismic license conditions that may adopted by the NRC. If the Utility is unable to comply with the new requirements or license conditions, the NRC may order the Utility to cease operating Diablo Canyon or deny the Utility's re-licensing application. Alternatively, the Utility may determine that compliance is not economically feasible and may choose to cease operating Diablo Canyon.

Hinkley Natural Gas Compressor Station

The Utility is legally responsible for remediating groundwater contamination caused by hexavalent chromium used in the past at the Hinkley natural gas compressor site. As discussed above in the section entitled "Environmental Matters," in Item 2: Management's Discussion and Analysis of Financial Condition and Results of Operations, several orders have been issued to require the Utility to take measures to remediate the underground chromium plume and abate the effects of the contamination on the environment, including an order requiring the Utility to offer affected residents a choice to either have the Utility install a permanent whole house water replacement system or purchase their property. Eligible residents were given until October 15, 2012 to make a choice and the majority have chosen to have the Utility purchase their property. For residents who have chosen a water replacement system, the Utility is required to maintain and operate the 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.

In August 2012, the Regional Board issued a draft environmental impact report ("EIR") that evaluated several alternatives for remediating groundwater contamination using a combination of different remedial methods, including using pumped groundwater from extraction wells to irrigate agricultural land and in-situ treatment of the contaminated water. The Utility expects that the Regional Board will consider certification of the final EIR in 2013.

The Utility's remediation and abatement costs associated with the Hinkley natural gas compressor site are not recoverable through rates or insurance. As a result, costs incurred for remediation at the Hinkley natural gas compressor site, as well as changes in the environmental remediation liability for the Hinkley natural gas compressor site, have materially affected PG&E Corporation's and the Utility's financial condition and results of operations.

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, estimates and assumptions regarding the amount of liability incurred may be subject to further changes. Future changes in estimates may have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

During the quarter ended September 30, 2012, PG&E Corporation made equity contributions totaling $150 million to the Utility in order to maintain the 52% common equity component of its CPUC-authorized capital structure. Neither PG&E Corporation nor the Utility made any sales of unregistered equity securities during the quarter ended September 30, 2012.

Issuer Purchases of Equity Securities

During the quarter ended September 30, 2012, PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. During the quarter ended September 30, 2012, the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.

ITEM 5. OTHER INFORMATION

Ratio of Earnings to Fixed Charges and Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends

The Utility's earnings to fixed charges ratio for the nine months ended September 30, 2012 was 2.73. The Utility's earnings to combined fixed charges and preferred stock dividends ratio for the nine months ended September 30, 2012 was 2.68. The statement of the foregoing ratios, together with the statements of the computation of the foregoing ratios filed as Exhibits 12.1 and 12.2 hereto, are included herein for the purpose of incorporating such information and Exhibits into the Utility's Registration Statement Nos. 33-62488 and 333-172394 relating to various series of the Utility's first preferred stock and its senior notes, respectively.

PG&E Corporation's earnings to fixed charges ratio for the nine months ended September 30, 2012 was 2.64. The statement of the foregoing ratio, together with the statement of the computation of the foregoing ratio filed as Exhibit 12.3 hereto, is included herein for the purpose of incorporating such information and Exhibit into PG&E Corporation's Registration Statement No. 333-172393 relating to its senior notes.

ITEM 6. EXHIBITS

4.1	Eighteenth Supplemental Indenture dated as of August 16, 2012 relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 2.45% Senior Notes due August 15, 2022 and $350,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.75% Senior Notes due August 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 16, 2012 (File No. 1-2348), Exhibit 4.1)
12.1	Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company
12.2	Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company
12.3	Computation of Ratios of Earnings to Fixed Charges for PG&E Corporation
31.1	Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002
*32.1	Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002
*32.2	Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

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

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrants have duly caused this Quarterly Report on Form 10-Q to be signed on their behalf by the undersigned thereunto duly authorized.

PG&E CORPORATION

KENT M. HARVEY

Kent M. Harvey
Senior Vice President and Chief Financial Officer
(duly authorized officer and principal financial officer)

PACIFIC GAS AND ELECTRIC COMPANY

DINYAR B. MISTRY

Dinyar B. Mistry
Vice President, Chief Financial Officer and Controller
(duly authorized officer and principal financial officer)

Dated: October 29, 2012

EXHIBIT INDEX

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