PG&E Corp
Form 10-Q
October 30, 2013

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, 2013

OR

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

For the transition period from ___________ to __________

Commission File Number	Exact Name of Registrant as Specified in its Charter	State or Other Jurisdiction of Incorporation	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	PG&E Corporation
77 Beale Street	77 Beale Street
P.O. Box 770000	P.O. Box 770000
San Francisco, California 94177	San Francisco, California 94177

Address of principal executive offices, including zip code

Pacific Gas and Electric Company	PG&E Corporation
(415) 973-7000	(415) 973-1000

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 22, 2013:

PG&E Corporation:	449,295,292
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, 2013
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GLOSSARY

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

2012 Annual Report	PG&E Corporation's and Pacific Gas and Electric Company's combined Annual Report on Form 10-K for the year ended December 31, 2012, including the information incorporated by reference into the report
ALJ	administrative law judge
ASU	accounting standards update
CAISO	California Independent System Operator
CARB	California Air Resources Board
CPUC	California Public Utilities Commission
CRRs	congestion revenue rights
DRA	Division of Ratepayer Advocates, now known as Office of Ratepayer Advocates
EPA	Environmental Protection Agency
EPS	earnings per common share
FERC	Federal Energy Regulatory Commission
GAAP	generally accepted accounting principles
GHG	greenhouse gas
GRC	general rate case
GT&S	gas transmission and storage
IRS	Internal Revenue Service
NEIL	Nuclear Electric Insurance Limited
NRC	Nuclear Regulatory Commission
OSC	CPUC Order to Show Cause
PSEP	pipeline safety enhancement plan
Regional Board	California Regional Water Quality Control Board, Lahontan Region
ROE	return on equity
SEC	U.S. Securities and Exchange Commission
SED	Safety and Enforcement Division of the CPUC, formerly known as the Consumer Protection and Safety Division or the CPSD
TO	transmission owner
TURN	The Utility Reform Network
Utility	Pacific Gas and Electric Company
VIE(s)	variable interest entity(ies)

PART I. FINANCIAL INFORMATION
ITEM 1. CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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)	2013	2012	2013	2012
Operating Revenues				
Electric	$3,517	$3,323	$9,375	$9,026
Natural gas	658	653	2,248	2,184
Total operating revenues	4,175	3,976	11,623	11,210
Operating Expenses				
Cost of electricity	1,645	1,283	3,817	3,104
Cost of natural gas	131	118	656	593
Operating and maintenance	1,585	1,344	4,179	4,138
Depreciation, amortization, and decommissioning	523	617	1,542	1,807
Total operating expenses	3,884	3,362	10,194	9,642
Operating Income	291	614	1,429	1,568
Interest income	2	2	6	6
Interest expense	(179)	(178)	(532)	(528)
Other income, net	26	26	78	84
Income Before Income Taxes	140	464	981	1,130
Income tax (benefit) provision	(24)	100	243	291
Net Income	164	364	738	839
Preferred stock dividend requirement of subsidiary	3	3	10	10
Income Available for Common Shareholders	$161	$361	$728	$829
Weighted Average Common Shares Outstanding, Basic	446	428	441	422
Weighted Average Common Shares Outstanding, Diluted	447	429	442	423
Net Earnings Per Common Share, Basic	$0.36	$0.84	$1.65	$1.96
Net Earnings Per Common Share, Diluted	$0.36	$0.84	$1.65	$1.96
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)	2013	2012	2013	2012
Net Income	$164	$364	$738	$839
Other Comprehensive Income				
Pension and other postretirement benefit plans				
Amortization of prior service cost (net of taxes of $5, $5, $14, and $15, at respective dates)	6	7	18	19
Amortization of actuarial loss (net of taxes of $11, $12, $35, and $38, at respective dates)	18	18	52	58
Amortization of transition obligation (net of taxes of $0, $2, $0, and $6, at respective dates)	-	4	-	12
Transfer to regulatory account (net of taxes of $13, $14, $39, and $44, at respective dates)	(20)	(21)	(58)	(63)
Gain (loss) on investments (net of taxes of $2, $0, $13, and $0, at respective dates)	(3)	-	19	-
Total other comprehensive income	1	8	31	26
Comprehensive Income	165	372	769	865
Preferred stock dividend requirement of subsidiary	3	3	10	10
Comprehensive Income Attributable to Common Shareholders	$162	$369	$759	$855

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions)	(Unaudited) Balance At September 30, 2013	December 31, 2012
ASSETS		
Current Assets		
Cash and cash equivalents	$ 281	$ 401
Restricted cash	301	330
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $81 and $87 at respective dates)	1,099	937
Accrued unbilled revenue	809	761
Regulatory balancing accounts	1,004	936
Other	286	365
Regulatory assets	483	564
Inventories:		
Gas stored underground and fuel oil	184	135
Materials and supplies	316	309
Income taxes receivable	377	211
Other	382	172
Total current assets	5,522	5,121
Property, Plant, and Equipment		
Electric	41,939	39,701
Gas	13,381	12,571
Construction work in progress	1,996	1,894
Other	1	1
Total property, plant, and equipment	57,317	54,167
Accumulated depreciation	(17,560)	(16,644)
Net property, plant, and equipment	39,757	37,523
Other Noncurrent Assets		
Regulatory assets	6,827	6,809
Nuclear decommissioning trusts	2,272	2,161
Income taxes receivable	163	176
Other	673	659
Total other noncurrent assets	9,935	9,805
TOTAL ASSETS	$ 55,214	$ 52,449

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited) Balance At	
(in millions, except share amounts)	September 30, 2013	December 31, 2012
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term borrowings	$ 953	$ 492
Long-term debt, classified as current	1,288	400
Accounts payable:		
Trade creditors	1,303	1,241
Disputed claims and customer refunds	156	157
Regulatory balancing accounts	1,002	634
Other	388	444
Interest payable	852	870
Income taxes payable	39	6
Other	1,663	2,012
Total current liabilities	7,644	6,256
Noncurrent Liabilities		
Long-term debt	11,918	12,517
Regulatory liabilities	5,343	5,088
Pension and other postretirement benefits	3,711	3,575
Asset retirement obligations	2,946	2,919
Deferred income taxes	7,275	6,748
Other	2,117	2,020
Total noncurrent liabilities	33,310	32,867
Commitments and Contingencies (Note 10)		
Equity		
Shareholders' Equity		
Preferred stock	-	-
Common stock, no par value, authorized 800,000,000 shares, 448,590,070 and 430,718,293 shares outstanding at respective dates	9,212	8,428
Reinvested earnings	4,866	4,747
Accumulated other comprehensive loss	(70)	(101)
Total shareholders' equity	14,008	13,074
Noncontrolling Interest - Preferred Stock of Subsidiary	252	252
Total equity	14,260	13,326
TOTAL LIABILITIES AND EQUITY	$ 55,214	$ 52,449

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	(Unaudited) Nine Months Ended September 30,	
(in millions)	2013	2012
Cash Flows from Operating Activities		
Net income	$ 738	$ 839
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	1,542	1,807
Allowance for equity funds used during construction	(78)	(79)
Deferred income taxes and tax credits, net	527	624
PSEP disallowed capital expenditures	196	-
Other	274	230
Effect of changes in operating assets and liabilities:		
Accounts receivable	(160)	(326)
Inventories	(56)	(34)
Accounts payable	84	(55)
Income taxes receivable/payable	(133)	69
Other current assets and liabilities	(269)	16
Regulatory assets, liabilities, and balancing accounts, net	12	66
Other noncurrent assets and liabilities	156	295
Net cash provided by operating activities	2,833	3,452
Cash Flows from Investing Activities		
Capital expenditures	(3,881)	(3,361)
Decrease (increase) in restricted cash	29	(38)
Proceeds from sales and maturities of nuclear decommissioning trust investments	1,152	903
Purchases of nuclear decommissioning trust investments	(1,150)	(964)
Other	37	101
Net cash used in investing activities	(3,813)	(3,359)
Cash Flows from Financing Activities		
Borrowings under revolving credit facilities	140	-
Net issuances (repayments) of commercial paper, net of discount of $1 and $3 at respective dates	322	(1,247)
Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $9 and $10 at respective dates	741	1,140
Long-term debt matured or repurchased	(461)	(50)
Energy recovery bonds matured	-	(313)
Common stock issued	724	702
Common stock dividends paid	(583)	(556)

Other		(23	)		14	
Net cash provided by (used in) financing activities		860			(310	)
Net change in cash and cash equivalents		(120	)		(217	)
Cash and cash equivalents at January 1		401			513	
Cash and cash equivalents at September 30	$	281		$	296	
Supplemental disclosures of cash flow information						
Cash received (paid) for:						
Interest, net of amounts capitalized	$	(499	)	$	(486	)
Income taxes, net		(65	)		114	
Supplemental disclosures of noncash investing and financing activities						
Common stock dividends declared but not yet paid	$	204		$	195	
Capital expenditures financed through accounts payable		277			228	
Noncash common stock issuances		17			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)	2013	2012	2013	2012
Operating Revenues				
Electric	$3,517	$3,321	$9,372	$9,022
Natural gas	657	653	2,248	2,184
Total operating revenues	4,174	3,974	11,620	11,206
Operating Expenses				
Cost of electricity	1,645	1,283	3,817	3,104
Cost of natural gas	131	118	656	593
Operating and maintenance	1,583	1,343	4,175	4,134
Depreciation, amortization, and decommissioning	523	617	1,542	1,807
Total operating expenses	3,882	3,361	10,190	9,638
Operating Income	292	613	1,430	1,568
Interest income	2	2	6	5
Interest expense	(172)	(172)	(513)	(511)
Other income, net	20	19	66	64
Income Before Income Taxes	142	462	989	1,126
Income tax (benefit) provision	(20)	122	261	328
Net Income	162	340	728	798
Preferred stock dividend requirement	3	3	10	10
Income Available for Common Stock	$159	$337	$718	$788

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)	2013	2012	2013	2012
Net Income	$162	$340	$728	$798
Other Comprehensive Income				
Pension and other postretirement benefit plans				
Amortization of prior service cost (net of taxes of $5, $5, $14, and $15, at respective dates)	6	7	18	19
Amortization of actuarial loss (net of taxes of $11, $12, $34, and $38, at respective dates)	18	18	53	58
Amortization of transition obligation (net of taxes of $0, $2 $0, and $6, at respective dates)	-	4	-	12
Transfer to regulatory account (net of taxes of $13, $14, $39, and $44, at respective dates)	(20)	(21)	(58)	(63)
Total other comprehensive income	4	8	13	26
Comprehensive Income	$166	$348	$741	$824

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, 2013	December 31, 2012
ASSETS		
Current Assets		
Cash and cash equivalents	$ 60	$ 194
Restricted cash	301	330
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $81 and $87 at respective dates)	1,099	937
Accrued unbilled revenue	809	761
Regulatory balancing accounts	1,004	936
Other	289	366
Regulatory assets	483	564
Inventories:		
Gas stored underground and fuel oil	184	135
Materials and supplies	316	309
Income taxes receivable	377	186
Other	344	160
Total current assets	5,266	4,878
Property, Plant, and Equipment		
Electric	41,939	39,701
Gas	13,381	12,571
Construction work in progress	1,996	1,894
Total property, plant, and equipment	57,316	54,166
Accumulated depreciation	(17,559)	(16,643)
Net property, plant, and equipment	39,757	37,523
Other Noncurrent Assets		
Regulatory assets	6,827	6,809
Nuclear decommissioning trusts	2,272	2,161
Income taxes receivable	158	171
Other	411	381
Total other noncurrent assets	9,668	9,522
TOTAL ASSETS	$ 54,691	$ 51,923

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)	(Unaudited) Balance At September 30, 2013	December 31, 2012
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$ 693	$ 372
Long-term debt, classified as current	938	400
Accounts payable:		
Trade creditors	1,303	1,241
Disputed claims and customer refunds	156	157
Regulatory balancing accounts	1,002	634
Other	404	419
Interest payable	841	865
Income taxes payable	49	12
Other	1,443	1,794
Total current liabilities	6,829	5,894
Noncurrent Liabilities		
Long-term debt	11,918	12,167
Regulatory liabilities	5,343	5,088
Pension and other postretirement benefits	3,628	3,497
Asset retirement obligations	2,946	2,919
Deferred income taxes	7,484	6,939
Other	2,055	1,959
Total noncurrent liabilities	33,374	32,569
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 respective dates	1,322	1,322
Additional paid-in capital	5,516	4,682
Reinvested earnings	7,472	7,291
Accumulated other comprehensive loss	(80)	(93)
Total shareholders' equity	14,488	13,460
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 54,691	$ 51,923

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)	2013	2012
Cash Flows from Operating Activities		
Net income	$ 728	$ 798
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	1,542	1,807
Allowance for equity funds used during construction	(78)	(79)
Deferred income taxes and tax credits, net	545	633
PSEP disallowed capital expenditures	196	-
Other	231	189
Effect of changes in operating assets and liabilities:		
Accounts receivable	(162)	(327)
Inventories	(56)	(34)
Accounts payable	125	(31)
Income taxes receivable/payable	(154)	153
Other current assets and liabilities	(250)	15
Regulatory assets, liabilities, and balancing accounts, net	12	66
Other noncurrent assets and liabilities	147	315
Net cash provided by operating activities	2,826	3,505
Cash Flows from Investing Activities		
Capital expenditures	(3,881)	(3,361)
Decrease (increase) in restricted cash	29	(38)
Proceeds from sales and maturities of nuclear decommissioning trust investments	1,152	903
Purchases of nuclear decommissioning trust investments	(1,150)	(964)
Other	14	14
Net cash used in investing activities	(3,836)	(3,446)
Cash Flows from Financing Activities		
Net issuances (repayments) of commercial paper, net of discount of $1 and $3 at respective dates	322	(1,247)
Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $9 and $10 at respective dates	741	1,140
Long-term debt matured or repurchased	(461)	(50)
Energy recovery bonds matured	-	(313)
Preferred stock dividends paid	(10)	(10)
Common stock dividends paid	(537)	(537)
Equity contribution	835	715

Other		(14	)		25	
Net cash provided by (used in) financing activities		876			(277	)
Net change in cash and cash equivalents		(134	)		(218	)
Cash and cash equivalents at January 1		194			304	
Cash and cash equivalents at September 30	$	60		$	86	
Supplemental disclosures of cash flow information						
Cash received (paid) for:						
Interest, net of amounts capitalized	$	(487	)	$	(476	)
Income taxes, net		(86	)		174	
Supplemental disclosures of noncash investing and financing activities						
Capital expenditures financed through accounts payable	$	277		$	228	
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, a public utility operating in northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. The Utility is primarily regulated by the CPUC and the FERC. In addition, the 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. PG&E Corporation and the Utility operate in one segment.

The accompanying Condensed Consolidated Financial Statements have been prepared in accordance with 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 U.S. Securities and Exchange Commission 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, 2012 in the Condensed Consolidated Balance Sheets included in this quarterly report was derived from the audited Consolidated Balance Sheets in the 2012 Annual Report. This quarterly report should be read in conjunction with the 2012 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, 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 2012 Annual Report.

Variable Interest Entities

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 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. To determine whether the Utility was the primary beneficiary of any of these VIEs at September 30, 2013, it assessed 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, analyzed the variability in the VIE's gross margin, and considered whether it had any decision-making rights associated with the activities that are most significant to the VIE's performance, such as dispatch rights and operating and maintenance activities. The Utility's financial exposure is limited to the amount the Utility pays for delivered electricity and capacity. The Utility did not have any decision-making rights associated with any of the activities that are most significant to the economic performance of any of these VIEs. Since the Utility was not the primary beneficiary of any of these VIEs at September 30, 2013, it did not consolidate any of them.

PG&E Corporation affiliates have entered into four tax equity agreements to fund residential and commercial retail solar energy installations with four separate privately held funds that are considered VIEs. Under these agreements, PG&E Corporation has made cumulative lease payments and investment contributions of $363 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. At September 30, 2013 and December 31, 2012, the carrying amount of PG&E Corporation's investment in these agreements was $138 million and $166 million, respectively. PG&E Corporation determined that it does not have control over the companies' significant economic activities, such as the design of the companies, vendor selection, construction, and the ongoing operations of the companies. PG&E Corporation has no material remaining commitment to fund these agreements. Since PG&E Corporation was not the primary beneficiary of any of these VIEs at September 30, 2013, it did not consolidate any of them.

Pension and Other Postretirement Benefits

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

The net periodic benefit costs reflected in PG&E Corporation's Condensed Consolidated Financial Statements for the three and nine months ended September 30, 2013 and 2012 were as follows:

	Pension Benefits		Other Benefits	
	Three Months Ended September 30,			
(in millions)	2013	2012	2013	2012
Service cost for benefits earned	$121	$100	$14	$14
Interest cost	158	165	19	21
Expected return on plan assets	(162)	(150)	(20)	(19)
Amortization of transition obligation	-	-	-	6
Amortization of prior service cost	5	5	6	7
Amortization of net actuarial loss	28	29	1	1
Net periodic benefit cost	150	149	20	30
Less: transfer to regulatory account (1)	(66)	(75)	-	-
Total	$84	$74	$20	$30

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

	Pension Benefits		Other Benefits	
	Nine Months Ended September 30,			
(in millions)	2013	2012	2013	2012
Service cost for benefits earned	$351	$297	$40	$37
Interest cost	470	494	56	63
Expected return on plan assets	(487)	(449)	(60)	(58)
Amortization of transition obligation	-	-	-	18
Amortization of prior service cost	15	15	17	19
Amortization of net actuarial loss	83	92	4	4
Net periodic benefit cost	432	449	57	83
Less: transfer to regulatory account (1)	(179)	(225)	-	-
Total	$253	$224	$57	$83

(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.

Adoption of New Accounting Pronouncements

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income

In February 2013, the Financial Accounting Standards Board issued an ASU that requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income. The ASU became effective for PG&E Corporation and the Utility on January 1, 2013.

The changes, net of income tax, in PG&E Corporation's accumulated other comprehensive income (loss) for the three and nine months ended September 30, 2013 consist of the following:

(in millions, net of income tax)	Pension Benefits	Other Benefits	Other Investments	Total
	Three Months Ended September 30, 2013			
Beginning balance	$(28)	$(69)	$26	$(71)
Other comprehensive income before reclassifications	(20)	-	(3)	(23)
Amounts reclassified from other comprehensive income:				
Amortization of prior service cost (1)	3	3	-	6
Amortization of net actuarial loss (1)	17	1	-	18
Net current period other comprehensive income (loss)	-	4	(3)	1
Ending balance	$(28)	$(65)	$23	$(70)

(1) These components are included in the computation of net periodic pension and other postretirement costs. (See the "Pension and Other Postretirement Benefits" table above for additional details.)

(in millions, net of income tax)	Pension Benefits	Other Benefits	Other Investments	Total
	Nine Months Ended September 30, 2013			
Beginning balance	$ (28)	$ (77)	$ 4	$ (101)
Other comprehensive income before reclassifications	(58)	-	19	(39)
Amounts reclassified from other comprehensive income:				
Amortization of prior service cost (1)	9	9	-	18
Amortization of net actuarial loss (1)	49	3	-	52
Net current period other comprehensive income (loss)	-	12	19	31
Ending balance	$ (28)	$ (65)	$ 23	$ (70)

(1) These components are included in the computation of net periodic pension and other postretirement costs. (See the "Pension and Other Postretirement Benefits" table above for additional details.)

There was no material difference between PG&E Corporation and the Utility for the information disclosed above, with the exception of other investments which are held by PG&E Corporation.

Disclosures about Offsetting Assets and Liabilities

In January 2013, the Financial Accounting Standards Board issued an ASU that clarifies the scope of disclosures about offsetting assets and liabilities. The guidance requires an entity to disclose gross and net information about derivatives that are offset in the balance sheet or subject to an enforceable master-netting arrangement or similar agreement. The ASU became effective for PG&E Corporation and the Utility on January 1, 2013. (See Note 7 below.)

NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

Regulatory Assets

Long-Term Regulatory Assets

Long-term regulatory assets are composed of the following:

	Balance at	
(in millions)	September 30, 2013	December 31, 2012
Pension benefits	$ 3,356	$ 3,275
Deferred income taxes	1,772	1,627
Utility retained generation	515	552
Environmental compliance costs	609	604
Price risk management	144	210
Electromechanical meters	150	194
Unamortized loss, net of gain, on reacquired debt	140	141
Other	141	206
Total long-term regulatory assets	$ 6,827	$ 6,809

Regulatory Liabilities

Long-Term Regulatory Liabilities

Long-term regulatory liabilities are composed of the following:

	Balance at	
(in millions)	September 30, 2013	December 31, 2012
Cost of removal obligations	$ 3,805	$ 3,625
Recoveries in excess of asset retirement obligations	674	620
Public purpose programs	594	590
Other	270	253
Total long-term regulatory liabilities	$ 5,343	$ 5,088

Regulatory Balancing Accounts

The Utility's recovery of a significant portion of revenue requirements and costs is decoupled from the volume of sales. The Utility records (1) differences between actual customer billings and the Utility's authorized revenue requirement, and (2) differences between incurred costs and customer billings. To the extent these differences are probable of recovery or refund, the Utility records a regulatory balancing account receivable or payable. Regulatory balancing accounts receivable and payable will fluctuate during the year based on seasonal electric and gas usage and the timing of when costs are incurred and customer revenues are collected.

Current Regulatory Balancing Accounts, Net

	Receivable (Payable) Balance at	
(in millions)	September 30, 2013	December 31, 2012
Distribution revenue adjustment mechanism	$ (3)	$ 219
Utility generation	(22)	117
Hazardous substance	75	56
Public purpose programs	(100)	(83)
Gas fixed cost	179	44
Energy recovery bonds	(170)	(43)
Energy procurement	281	77
U.S. Department of Energy Settlement	(279)	(250)
GHG allowance auction proceeds (1)	(250)	-
Other	291	165
Total regulatory balancing accounts, net	$ 2	$ 302

(1)The CARB has adopted regulations that established a state-wide, "cap-and-trade" program (effective January 1, 2013) that sets a gradually declining limit on the amount of GHGs that may be emitted each year. This balancing account is used to record proceeds collected by the Utility for GHG emission allowances associated with the cap-and-trade program. These amounts will be refunded to customers in future periods.

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NOTE 4: DEBT

Senior Notes

In June 2013, the Utility issued $375 million principal amount of 3.25% Senior Notes due June 15, 2023 and $375 million principal amount of 4.60% Senior Notes due June 15, 2043. The proceeds were used to repurchase $461 million principal amount, net of $15 million of premiums and $6 million of accrued interest, of the Utility's $1.0 billion outstanding 4.80% Senior Notes due March 1, 2014, to repay a portion of outstanding commercial paper, and for general corporate purposes.

Revolving Credit Facilities

In April 2013, PG&E Corporation and the Utility amended and restated their revolving credit facilities to extend their termination dates from May 31, 2016 to April 1, 2018. These agreements contain substantially similar terms as their original 2011 credit agreements.

At September 30, 2013, PG&E Corporation had $260 million of cash borrowings and no letters of credit outstanding under its $300 million revolving credit facility.

At September 30, 2013, the Utility had no cash borrowings and $91 million of letters of credit outstanding under its $3.0 billion revolving credit facility.

Pollution Control Bonds

At September 30, 2013, 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 0.05% to 0.07%. At September 30, 2013, the interest rates on the $309 million principal amount of pollution control bonds Series 2009 A-D and the related loan agreements ranged from 0.01% to 0.04%.

Commercial Paper Program

At September 30, 2013, the Utility had $693 million of commercial paper outstanding supported by available capacity under its revolving credit facility.

NOTE 5: EQUITY

PG&E Corporation's and the Utility's changes in equity for the nine months ended September 30, 2013 were as follows:

(in millions)	PG&E Corporation Total Equity	Utility Total Shareholders' Equity
Balance at December 31, 2012	$ 13,326	$ 13,460
Comprehensive income	769	741
Equity contributions	-	835
Common stock issued	741	-
Share-based compensation expense	43	(1)

Common stock dividends declared		(609)		(537)
Preferred stock dividend requirement		-		(10)
Preferred stock dividend requirement of subsidiary		(10)		-
Balance at September 30, 2013	$	14,260	$	14,488

In May 2013, PG&E Corporation entered into a new equity distribution agreement providing for the sale of PG&E Corporation common stock having an aggregate gross sales price of up to $400 million. As of September 30, 2013, PG&E Corporation sold common stock having an aggregate gross sales price of $150 million under this agreement. During the three and nine months ended September 30, 2013, PG&E Corporation paid commissions of $1 million, respectively, under this agreement.

During the nine months ended September 30, 2013, PG&E Corporation issued 18 million shares of its common stock for aggregate net cash proceeds of $724 million in the following transactions:

- 7 million shares were sold in an underwritten public offering for cash proceeds of $300 million, net of fees and commissions;
- 6 million shares were issued for cash proceeds of $212 million under the PG&E Corporation 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans; and
- 5 million shares were sold for cash proceeds of $212 million, net of commissions paid of $2 million, under equity distribution agreements.

NOTE 6: EARNINGS PER SHARE

PG&E Corporation's basic 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)	2013	2012	2013	2012
Income available for common shareholders	$161	$361	$728	$829
Weighted average common shares outstanding, basic	446	428	441	422
Add incremental shares from assumed conversions:				
Employee share-based compensation	1	1	1	1
Weighted average common share outstanding, diluted	447	429	442	423
Total earnings per common share, diluted	$0.36	$0.84	$1.65	$1.96

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

NOTE 7: DERIVATIVES

The Utility uses both derivative and non-derivative contracts in managing its exposure to commodity-related price risk, including forward contracts, swap agreements, futures contracts, and option contracts.

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

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

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

Presentation of Derivative Instruments in the Financial Statements

In the Condensed Consolidated Balance Sheets, derivatives are presented on a net basis by counterparty where the right and the intention to offset exists under a master netting agreement. All derivatives that are subject to a master netting arrangement have been netted. The net balances include outstanding cash collateral associated with derivative positions.

At September 30, 2013, 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	$31	$(12)	$19	$38
Other noncurrent assets – other	66	(5)	-	61
Current liabilities – other	(162)	12	106	(44)
Noncurrent liabilities – other	(149)	5	23	(121)
Total commodity risk	$(214)	$-	$148	$(66)

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

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

			Cash Collateral	
Current assets – other	$48	$(25)	$36	$59
Other noncurrent assets – other	99	(11)	-	88
Current liabilities – other	(255)	25	115	(115)
Noncurrent liabilities – other	(221)	11	14	(196)
Total commodity risk	$(329)	$-	$165	$(164)

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Gains and losses associated with price risk management activities were recorded as follows:

	Commodity Risk			
	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2013	2012	2013	2012
Unrealized gain - regulatory assets and liabilities (1)	$40	$162	$115	$327
Realized loss - cost of electricity (2)	(57)	(108)	(136)	(383)
Realized loss - cost of natural gas (2)	(2)	(5)	(14)	(32)
Total commodity risk	$(19)	$49	$(35)	$(88)

(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.

Volume of Derivative Activity

At September 30, 2013, the volumes of PG&E Corporation's and the Utility's outstanding derivatives were as follows:

		Contract Volume (1)			
Underlying Product	Instruments	Less Than 1 Year	1 Year or Greater but Less Than 3 Years	3 Years or Greater but Less Than 5 Years	5 Years or Greater (2)
Natural Gas (3) (MMBtus (4))	Forwards and Swaps	282,212,809	84,938,674	4,907,500	-
	Options	206,604,635	115,753,835	1,500,000	-
Electricity (Megawatt-hours)	Forwards and Swaps	2,537,023	2,396,080	2,008,046	1,685,781
	Options	95,158	239,233	239,015	24,350
	Congestion Revenue Rights	57,166,228	78,318,934	60,465,135	11,609,557

(1) Amounts shown reflect the total gross derivative volumes by commodity type that are expected to settle in each period.
(2) Derivatives in this category expire between 2018 and 2022.
(3) Amounts shown are for the combined positions of the electric fuels and core gas portfolios.
(4) Million British Thermal Units.

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

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

(1) Amounts shown reflect the total gross derivative volumes by commodity type that are expected to settle in each period.
(2) Derivatives in this category expire between 2018 and 2022.
(3) Amounts shown are for the combined positions of the electric fuels and core gas portfolios.
(4) Million British Thermal Units.

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. If the Utility's credit rating was to fall below investment grade, the Utility would be required to post additional cash immediately to fully collateralize some of its net liability derivative positions. At September 30, 2013, the Utility's credit rating was investment grade.

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

	Balance at	
(in millions)	September 30, 2013	December 31, 2012
Derivatives in a liability position with credit risk-related contingencies that are not fully collateralized	$ (133)	$ (266)
Related derivatives in an asset position	29	59
Collateral posting in the normal course of business related to these derivatives	112	103
Net position of derivative contracts/additional collateral posting requirements (1)	$ 8	$ (104)

(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, price risk management instruments, and other investments 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 and other investments are held by PG&E Corporation and not the Utility):

	Fair Value Measurements At September 30, 2013				
(in millions)	Level 1	Level 2	Level 3	Netting (1)	Total
Assets:					
Money market investments	$214	$-	$-	$-	$214
Nuclear decommissioning trusts					
Money market investments	26	-	-	-	26
U.S. equity securities	1,009	10	-	-	1,019
Non-U.S. equity securities	435	-	-	-	435
U.S. government and agency securities	782	148	-	-	930
Municipal securities	-	26	-	-	26
Other fixed-income securities	-	128	-	-	128
Total nuclear decommissioning trusts (2)	2,252	312	-	-	2,564
Price risk management instruments (Note 7)					
Electricity	1	27	65	2	95
Gas	-	4	-	-	4
Total price risk management instruments	1	31	65	2	99
Rabbi trusts					
Fixed-income securities	-	30	-	-	30
Life insurance contracts	-	70	-	-	70
Total rabbi trusts	-	100	-	-	100
Long-term disability trust					
Money market investments	5	-	-	-	5
U.S. equity securities	-	11	-	-	11
Non-U.S. equity securities	-	10	-	-	10
Fixed-income securities	-	116	-	-	116
Total long-term disability trust	5	137	-	-	142
Other investments	51	-	-	-	51
Total assets	$2,523	$580	$65	$2	$3,170
Liabilities:					
Price risk management instruments (Note 7)					
Electricity	$53	$100	$147	$(140)	$160
Gas	6	5	-	(6)	5
Total liabilities	$59	$105	$147	$(146)	$165

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
(2) Represents amount before deducting $292 million of deferred taxes primarily related to appreciation of investment value.

(in millions)	Fair Value Measurements At December 31, 2012 Level 1	Level 2	Level 3	Netting (1)	Total
Assets:					
Money market investments	$209	$-	$-	$-	$209
Nuclear decommissioning trusts					
Money market investments	21	-	-	-	21
U.S. equity securities	940	9	-	-	949
Non-U.S. equity securities	379	-	-	-	379
U.S. government and agency securities	681	139	-	-	820
Municipal securities	-	59	-	-	59
Other fixed-income securities	-	173	-	-	173
Total nuclear decommissioning trusts (2)	2,021	380	-	-	2,401
Price risk management instruments (Note 7)					
Electricity	1	60	80	6	147
Gas	-	5	1	(6)	-
Total price risk management instruments	1	65	81	-	147
Rabbi trusts					
Fixed-income securities	-	30	-	-	30
Life insurance contracts	-	72	-	-	72
Total rabbi trusts	-	102	-	-	102
Long-term disability trust					
Money market investments	10	-	-	-	10
U.S. equity securities	-	14	-	-	14
Non-U.S. equity securities	-	11	-	-	11
Fixed-income securities	-	136	-	-	136
Total long-term disability trust	10	161	-	-	171
Total assets	$2,241	$708	$81	$-	$3,030
Liabilities:					
Price risk management instruments (Note 7)					
Electricity	$155	$144	$160	$(156)	$303
Gas	8	9	-	(9)	8
Total liabilities	$163	$153	$160	$(165)	$311

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
(2) Represents amount before deducting $240 million of deferred taxes primarily related to 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 tables above. All investments that are valued using a net asset value per share can be redeemed quarterly with notice not to exceed 90 days.

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 the 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, that are valued using a net asset value per share and are composed of equity securities traded publicly on exchanges across multiple industry sectors in the U.S. and other regions of the world and 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.

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. Exchange-traded options are valued using observable market data and market-corroborated data and 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.

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.

Other Investments

Other investments in common stock are valued based on unadjusted prices for the investments and are actively traded on public exchanges. These investments are therefore considered Level 1 assets.

Transfers between Levels

PG&E Corporation and the Utility recognize 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, 2013.

Level 3 Measurements and Sensitivity Analysis

The Utility's market and credit risk management function 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 function and the Utility's finance function collaborate to determine the appropriate fair value methodologies and classification for each derivative. Inputs used and the 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, 2013				
Fair Value Measurement	Assets	Liabilities	Valuation Technique	Unobservable Input	Range (1)
Congestion revenue rights	$65	$13	Market approach	CRR auction prices	(7.58) - $7.93
Power purchase agreements	$-	$134	Discounted cash flow	Forward prices	10.36 - $54.86

(1) Represents price per megawatt-hour

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

(1) Represents price per megawatt-hour

Level 3 Reconciliation

The following tables present the reconciliation for Level 3 price risk management instruments for the three and nine months ended September 30, 2013 and 2012:

	Price Risk Management Instruments	
(in millions)	2013	2012
Liability balance as of July 1	$(76)	$(80)
Realized and unrealized gains (losses):		
Included in regulatory assets and liabilities or balancing accounts (1)	(6)	(4)
Liability balance as of September 30	$(82)	$(84)

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

(in millions)	Price Risk Management Instruments 2013	2012
Liability balance as of January 1	$(79)	$(74)
Realized and unrealized gains (losses):		
Included in regulatory assets and liabilities or balancing accounts (1)	(3)	(10)
Liability balance as of September 30	$(82)	$(84)

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

Financial Instruments

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

- The fair values of cash, restricted cash, net accounts receivable, short-term borrowings, accounts payable, customer deposits, and the Utility's variable rate pollution control bond loan agreements approximate their carrying values at September 30, 2013 and December 31, 2012, 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 bonds and PG&E Corporation's fixed-rate senior notes were based on quoted market prices at September 30, 2013 and December 31, 2012.

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, 2013		December 31, 2012	
(in millions)	Carrying Amount	Level 2 Fair Value	Carrying Amount	Level 2 Fair Value
Debt (Note 4)				
PG&E Corporation	$350	$359	$349	$371
Utility	11,934	12,750	11,645	13,946

Available for Sale Investments

The following table provides a summary of available-for-sale investments:

(in millions)	Amortized Cost	Total Unrealized Gains	Total Unrealized Losses	Total Fair Value
As of September 30, 2013				
Nuclear decommissioning trusts				
Money market investments	$26	$-	$-	$26
Equity securities				
U.S.	267	753	(1)	1,019
Non-U.S.	205	230	-	435
Debt securities				
U.S. government and agency securities	870	63	(3)	930
Municipal securities	24	2	-	26
Other fixed-income securities	128	1	(1)	128
Total nuclear decommissioning trusts (1)	1,520	1,049	(5)	2,564
Other investments	13	38	-	51
Total	$1,533	$1,087	$(5)	$2,615
As of December 31, 2012				
Nuclear decommissioning trusts				
Money market investments	$21	$-	$-	$21
Equity securities				
U.S.	331	618	-	949
Non-U.S.	199	181	(1)	379
Debt securities				
U.S. government and agency securities	723	97	-	820
Municipal securities	56	4	(1)	59
Other fixed-income securities	168	5	-	173
Total (1)	$1,498	$905	$(2)	$2,401

(1) Represents amounts before deducting $292 million and $240 million at September 30, 2013 and December 31, 2012, respectively, of deferred taxes primarily related to appreciation of investment value.

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

(in millions)	As of September 30, 2013
Less than 1 year	$ 17
1–5 years	512
5–10 years	241
More than 10 years	314
Total maturities of debt securities	$ 1,084

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
(in millions)				
Proceeds from sales and maturities of nuclear decommissioning trust investments	$357	$237	$1,152	$903
Gross realized gains on sales of securities held as available-for-sale	7	3	44	17
Gross realized losses on sales of securities held as available-for-sale	(4)	(6)	(10)	(13)

NOTE 9: RESOLUTION OF REMAINING CHAPTER 11 DISPUTED CLAIMS

Various electricity suppliers filed claims in the Utility's proceeding filed under Chapter 11 of the U.S. Bankruptcy Code seeking payment for energy supplied to the Utility's customers 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 California Power Exchange wholesale electricity markets during this period.

While the FERC and judicial proceedings are pending, the Utility has pursued, and continues to pursue, settlements with electricity suppliers. The Utility entered into a number of settlement agreements with various electricity suppliers to resolve some of these disputed claims and to resolve the Utility's refund claims against these electricity suppliers. These settlement agreements provide that the amounts payable by the parties are, in some instances, subject to adjustment based on the outcome of the various refund offset and interest issues being considered by the FERC. The Utility is uncertain when and how the remaining disputed claims will be resolved.

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.

At September 30, 2013 and December 31, 2012, the remaining net disputed claims liability consisted of $156 million and $157 million, respectively, of remaining net disputed claims (classified on the Condensed Consolidated Balance Sheets within accounts payable – disputed claims and customer refunds) and $704 million and $685 million, respectively, of accrued interest (classified on the Condensed Consolidated Balance Sheets within interest payable).

At September 30, 2013 and December 31, 2012 the Utility held $291 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.

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 regulatory proceedings, investigations, nuclear liability, legal matters and environmental remediation.

Commitments

In the ordinary course of business, the Utility enters into various agreements to purchase power and electric capacity; natural gas supply, transportation, and storage; nuclear fuel supply and services; and various other commitments. The Utility disclosed its commitments at December 31, 2012 in Note 15 of the Notes to the Consolidated Financial Statements in the 2012 Annual Report. During the nine months ended September 30, 2013, the Utility entered into several renewable energy and other power purchase agreements, resulting in a total commitment of $1.9 billion over the next one to twenty-five years. These agreements have been approved by the CPUC and have completed major milestones with respect to construction.

Contingencies

PG&E Corporation and the Utility are subject to various laws and regulations and, in the normal course of business, are named as parties in a number of claims and lawsuits. In addition, penalties may be incurred for failure to comply with federal, state, or local laws and regulations. PG&E Corporation and the Utility record a provision for a loss contingency 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. The assessment of whether a loss is probable or a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Loss contingencies are reviewed quarterly and estimates are adjusted to reflect the impact of all known information, such as negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. PG&E Corporation's and the Utility's policy is to exclude anticipated legal costs from the provision for loss.

Natural Gas Matters

On September 9, 2010, a natural gas transmission pipeline owned and operated by the Utility ruptured in San Bruno, California. The ensuing explosion and fire resulted in the deaths of eight people, numerous personal injuries, and extensive property damage. Following the San Bruno accident, various regulatory proceedings, investigations, and lawsuits were commenced. The National Transportation Safety Board, an independent review panel appointed by the CPUC, and the SED completed investigations with respect to the San Bruno accident, placing the blame primarily on the Utility. As part of a rulemaking proceeding to consider the adoption of new natural gas safety regulations, the CPUC ordered all natural gas operators in California to submit proposed plans to modernize and upgrade their natural gas transmission systems as well as associated cost forecast and ratemaking proposals.

Pipeline Safety Enhancement Plan

The Utility's pipeline safety enhancement plan is a multi-year program to modernize and upgrade its natural gas transmission system. In December 2012, the CPUC approved most of the projects proposed in the PSEP but disallowed the Utility's request for rate recovery of a significant portion of costs the Utility forecasted it would incur through 2014. The CPUC authorized the Utility to recover costs, subject to the adopted capital and expense amounts, for activities including pipeline strength testing, pipeline replacement, in-line inspection, and the installation of automated valves. The CPUC prohibited the Utility from recovering the costs of pressure testing pipeline placed into service after January 1, 1956 for which the Utility is unable to produce pressure test records. The CPUC ordered the Utility to file an update PSEP application after the Utility completes its search and review of records relating to pipeline pressure validation for all 6,750 miles of the Utility's natural gas transmission pipelines.

On October 29, 2013, the Utility submitted its update application to present the results of its completed records search and review and to request approval of adjusted revenue requirements. Based on the information obtained through the records search and review, the Utility has proposed to change the scope and prioritization of PSEP work, including deferring some projects to after 2014 and accelerating other projects. The Utility has proposed net reductions to authorized costs for both its strength testing program (to test 658 miles rather than 783 miles) and its pipeline replacement program (to replace 143 miles rather than 186 miles). In August 2013, in anticipation of the Utility's update application, TURN and the CPUC's DRA requested the assigned ALJ for an order limiting the scope of the revenue requirement changes that the Utility could request in the update application to only those changes resulting from the records search and subsequent pressure validation based on those records, which could result in a disallowance of costs associated with the acceleration of projects. The ALJ has not yet addressed their request and it is uncertain how the information presented in the Utility's update application about accelerating or changing the scope of PSEP projects will be considered. The Utility has requested that the CPUC issue a final decision by August 2014 to approve the revised scope of PSEP projects and the net reduction in authorized costs.

Based on the proposed changes in the scope of PSEP projects through 2014, the Utility forecasts that total unrecoverable costs to complete this work will significantly exceed the amount previously forecasted primarily due to higher anticipated unit costs to replace pipeline segments. As a result, for the three months ended September 30, 2013, the Utility recorded a charge of $196 million, reflecting the increase in forecasted capital expenditures through 2014 that are expected to exceed the amount to be recovered. At September 30, 2013, the Utility has recorded cumulative charges of $549 million for disallowed PSEP-related capital expenditures, including $353 million recorded at December 31, 2012.

At September 30, 2013, capitalized PSEP costs of approximately $170 million are included in Property, Plant, and Equipment on the Condensed Consolidated Balance Sheets. The Utility could record additional charges if the CPUC does not approve the adjusted revenue requirements requested in the Utility's PSEP update application or if cost forecasts increase in the future. The CPUC also could make ratemaking adjustments to recovery of PSEP costs in connection with the pending CPUC investigations discussed below.

Pending CPUC Investigations

There are three CPUC investigative enforcement proceedings pending against the Utility that relate to (1) the Utility's safety recordkeeping for its natural gas transmission system, (2) the Utility's operation of its natural gas transmission pipeline system in or near locations of higher population density, and (3) the Utility's pipeline installation, integrity management, recordkeeping and other operational practices, and other events or courses of conduct, that could have led to or contributed to the San Bruno accident. Evidentiary hearings and briefing have been completed in each of these investigations.

The SED has recommended that the CPUC impose what the SED characterizes as a penalty of $2.25 billion on the Utility, allocated as follows: (1) $300 million as a fine to the State General Fund, (2) $435 million for a portion of PSEP costs that were previously disallowed by the CPUC and funded by shareholders, and (3) $1.515 billion to perform PSEP work that was previously approved by the CPUC, implement operational remedies, and for future PSEP costs. Other parties, including the City of San Bruno, TURN, the CPUC's DRA, and the City and County of San Francisco, have recommended total penalties of at least $2.25 billion, including fines payable to the State General Fund of differing amounts. The City of San Bruno also recommended that the Utility provide $150 million for a Peninsula Emergency Response Consortium, spend $100 million ($5 million per year for 20 years) to fund an independent advocacy trust (the California Pipeline Safety Trust), and provide funding for an independent monitor to oversee the implementation of the recommended remedial operational measures. TURN also recommended that the Utility bear expenses of $50 million to implement remedial measures and to pay for an independent monitor.

The record for the proceedings was closed on October 15, 2013. The CPUC's rules call for the CPUC ALJs to issue one or more presiding officers' decisions within 60 days of this date. The decisions will become the final decisions of the CPUC 30 days after issuance unless the Utility or another party files an appeal with the CPUC, or a CPUC commissioner requests that the CPUC review the decision, within such time. If an appeal or review request is filed, other parties have 15 days to provide comments but the CPUC could act before considering any comments.

At September 30, 2013 and December 31, 2012, PG&E Corporation's and the Utility's Condensed Consolidated Balance Sheets included an accrual of $200 million in other current liabilities for the minimum amount of fines deemed probable that the Utility will pay to the State General Fund. The Utility is unable to make a better estimate due to the many variables that could affect the final outcome, including how the total number and duration of violations will be determined; how the various penalty recommendations made by the SED and other parties will be considered; how the financial and tax impact of unrecoverable costs the Utility has incurred, and will continue to incur, to improve the safety and reliability of its pipeline system, will be considered; whether the Utility's costs to perform any required remedial actions will be considered; and how the CPUC responds to public pressure. Future changes in these estimates or the assumptions on which they are based could have a material impact on PG&E

Corporation's and the Utility's financial condition, results of operations, and cash flows. The CPUC may impose fines on the Utility that are materially higher than the amount accrued and may disallow PSEP costs that were previously authorized for recovery or other future costs. Disallowed costs would be charged to net income in the period incurred.

Other CPUC Enforcement Matters

In addition to the investigations that are pending against the Utility related to its natural gas operations and the San Bruno accident, the CPUC and/or SED are also considering the following matters. PG&E Corporation and the Utility are unable to estimate the amount or range of reasonably possible losses that may be incurred in connection with these matters.

Gas Safety Citation Program

California gas corporations are required to provide notice to the SED of any self-identified or self-corrected violations of certain state and federal regulations related to the safety of natural gas facilities and the corporations' natural gas operating practices. The SED is authorized to issue citations and impose fines for violations of certain state and federal regulations. In September 2013, the SED published a document explaining the internal procedures the SED staff intends to follow in assessing gas safety violations and determining appropriate enforcement action. The SED can consider several factors in exercising its discretion to impose fines or take other enforcement action based on the totality of the circumstances. Such factors include how the SED assesses the severity of the safety risk associated with each violation; how the SED determines the number of violations; how the SED determines the duration of the violations; how the SED considers other factors such as whether the violation was self-reported, and whether any corrective actions were taken. The SED's internal procedures also include a schedule of potential fine amounts that vary based on the severity of the safety risk posed by the violation.

In October 2013, the SED issued a citation related to one of the Utility's self-reports and imposed a fine of $140,000. The Utility has filed 58 self-reports with the SED, plus additional follow-up reports, that the SED has not yet addressed. The SED could issue additional citations and impose fines associated with these self-reports.

Orders to Show Cause

On August 19, 2013, the CPUC issued two OSCs related to a document submitted by the Utility on July 3, 2013 as "errata" to correct information about some segments in Lines 101 and 147 (two of the Utility's natural gas transmission pipelines that serve the San Francisco peninsula) that had been previously provided to the CPUC in October 2011 to allow the Utility to restore operating pressure on these pipelines. The first OSC directed the Utility to show why all orders issued by the CPUC to authorize increased operating pressure on the Utility's gas transmission pipelines should not be immediately suspended pending competent demonstration that the Utility's natural gas system records are reliable. It is uncertain when the CPUC will issue a decision on the first OSC. The second OSC ordered the Utility to show why it should not be penalized for violating CPUC rules that prohibit any person from misleading the CPUC, in connection with the errata submission. Among other recommendations submitted by intervening parties related to the second OSC, the DRA and TURN have recommended that the CPUC impose penalties of $12.7 million on the Utility. The CPUC is expected to issue a decision on the second OSC before the end of 2013. The CPUC could impose penalties on the Utility or take other enforcement action in connection with the OSCs.

Natural Gas Transmission Pipeline Rights-of-Way

In 2012, the Utility also notified the CPUC and the SED that the Utility is undertaking a system-wide effort to survey its transmission pipelines and identify and remove encroachments (such as building structures and vegetation overgrowth) from pipeline rights-of-way over a multi-year period. The SED could impose penalties on the Utility or take other enforcement action in connection with this matter.

Criminal Investigation

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

Third-Party Claims

In September 2013, the Utility agreed to settle the claims of substantially all of the remaining plaintiffs who sought compensation for personal injury and property damage, and other relief, including punitive damages, following the San Bruno accident. Approximately 165 lawsuits on behalf of approximately 525 plaintiffs have been filed against the Utility. For the three and nine months ended September 30, 2013, the Utility recorded a charge of $110 million to reflect its best estimate of probable loss for settlements reached in September 2013 and remaining third-party claims for personal injury, property damage, and damage to infrastructure, including claims by government entities. At September 30, 2013, the Utility has recorded cumulative charges of $565 million for third-party claims related to the San Bruno accident and has made cumulative payments of $389 million for settlements.

The following table presents changes in the third-party claims liability since the San Bruno accident in September 2010; the balance is included in other current liabilities in the 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		(211)
Balance at December 31, 2012		146
Additional loss accrued		110
Less: Payments		(80)
Balance at September 30, 2013	$	176

The Utility has liability insurance from various insurers who provide coverage at different policy limits that are triggered in sequential order or “layers.” Generally, as the policy limit for a layer is exhausted the next layer of insurance becomes available. The aggregate amount of insurance coverage for third-party liability attributable to the San Bruno accident is approximately $992 million in excess of a $10 million deductible. Through September 30, 2013, the Utility has recognized cumulative insurance recoveries of $354 million for third-party claims and related legal expenses. (The Utility has incurred cumulative legal expenses of $84 million in addition to the $565 million charges above). Insurance recoveries for the three and nine months ended September 30, 2013 were $25 million and $70 million, respectively. These amounts were recorded as a reduction to operating and maintenance expense in the Condensed Consolidated Statements of Income. Although the Utility believes that a significant portion of costs incurred for third-party claims (and associated legal expenses) relating to the San Bruno accident will ultimately be recovered through its insurance, it is unable to predict the amount and timing of additional insurance recoveries.

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. The plaintiffs allege that PG&E Corporation and the Utility engaged in unfair business practices in violation of California state law. The plaintiffs seek restitution and disgorgement, as well as compensatory and punitive damages.

PG&E Corporation and the Utility contest the plaintiffs' allegations. On May 23, 2013, the court granted PG&E Corporation's and the Utility's request to dismiss the complaint on the grounds that the CPUC has exclusive jurisdiction to adjudicate the issues raised by the plaintiffs' allegations. The plaintiffs have appealed the court's ruling to the California Court of Appeal. PG&E Corporation and the Utility are unable to estimate the amount or range of reasonably possible losses, if any, that may be incurred in connection with this matter.

Legal and Regulatory Contingencies

Accruals for other legal and regulatory contingencies (excluding amounts related to natural gas matters above) totaled $36 million at September 30, 2013 and $34 million at December 31, 2012. These amounts are included in other current liabilities in the Condensed Consolidated Balance Sheets. The resolution of these matters is not expected to have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows.

Nuclear Insurance

The Utility is a member of NEIL, which is a mutual insurer owned by utilities with nuclear facilities. NEIL provides insurance coverage for property damages and business interruption losses incurred by the Utility if a nuclear event were to occur at the Utility's two nuclear generating units at Diablo Canyon and the retired Humboldt Bay Unit 3. NEIL provides property damage and business interruption coverage of up to $3.2 billion per nuclear incident and $2 billion per non-nuclear incident for Diablo Canyon. Humboldt Bay Unit 3 has up to $131 million of coverage for nuclear and non-nuclear property damages. NEIL also provides coverage for damages caused by acts of terrorism at nuclear power plants.

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 $13.6 billion. The Utility purchased the maximum available public liability insurance of $375 million for Diablo Canyon. The balance is provided under a loss-sharing program among utilities owning nuclear reactors. The Price-Anderson Act does not apply to 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. The Utility has a separate 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 liability insurance. (See Note 15 of the Notes to the Consolidated Financial Statements of the 2012 Annual Report for additional information on the Utility's insurance coverage and premiums.)

Environmental Remediation Contingencies

The Utility has been, and may be required to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party under federal and state environmental laws. These sites include former manufactured gas plant sites, power plant sites, gas gathering sites, sites where natural gas compressor stations are located, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous substances. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if it did not deposit those substances on the site.

Given the complexities of the legal and regulatory environment and the inherent uncertainties involved in the early stages of a remediation project, the process for estimating remediation liabilities is subjective and requires significant judgment. The Utility records an environmental remediation liability when site assessments indicate that remediation is probable and the Utility can reasonably estimate the loss or a range of probable amounts. The Utility records an environmental remediation liability based on the lower end of the range of estimated probable costs, unless an amount within the range is a better estimate than any other amount. Amounts recorded are not discounted to their present value.

The environmental remediation liability is composed of the following:

	Balance at

(in millions)	September 30, 2013	December 31, 2012
Utility-owned natural gas compressor site near Topock, Arizona (1)	$ 268	$ 239
Utility-owned natural gas compressor site near Hinkley, California (1)	197	226
Former manufactured gas plant sites owned by the Utility or third parties	179	181
Utility-owned generation facilities (other than for fossil fuel-fired), other facilities, and third-party disposal sites	165	158
Fossil fuel-fired generation facilities formerly owned by the Utility	85	87
Decommissioning fossil fuel-fired generation facilities and sites	20	19
Total environmental remediation liability	$ 914	$ 910

(1) See “Natural Gas Compressor Sites” below.

At September 30, 2013, the Utility expected to recover $581 million of its environmental remediation liability through various ratemaking mechanisms authorized by the CPUC. One of these mechanisms allows the Utility rate recovery for 90% of its hazardous substance remediation costs for certain approved sites (including the Topock site) without a reasonableness review. The Utility may incur environmental remediation costs that it does not seek to recover in rates, such as the costs associated with the Hinkley site.

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. On July 17, 2013, the Regional Board certified a final environmental report evaluating the Utility's proposed remedial methods to contain and remediate the underground plume of hexavalent chromium and the potential environmental impacts. The Regional Board is expected to issue waste discharge permits in 2014 to allow for continued treatment of hexavalent chromium and issue a final clean-up order in 2015.

The Utility has implemented interim remediation measures to reduce the mass of the chromium plume, monitor and control movement of the plume, and provided replacement water to affected residents. As of September 30, 2013, approximately 350 residential households located near the plume boundary were covered by the Utility's whole house water replacement program and the majority have opted to accept the Utility's offer to purchase their properties. The Utility is required to maintain and operate the program 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.   The State of California recently proposed draft regulations for hexavalent chromium and is expected to issue a final standard in 2014.

The Utility's environmental remediation liability at September 30, 2013 reflects the Utility's best estimate of probable future costs associated with its final remediation plan and whole house water program. Future costs will depend on many factors, including the levels of hexavalent chromium the Utility is required to use as the standard for remediation, the required time period by which those standards must be met, the extent of the chromium plume boundary, and adoption of a final drinking water standard by the State of California. As more information becomes known regarding these factors, the Utility's cost estimates and the assumptions on which they are based regarding the amount of liability incurred may be subject to further changes. Future changes in estimates or assumptions may have a material impact on PG&E Corporation's and the Utility's future financial condition, results of operations, and cash flows.

Topock Site

The Utility's remediation and abatement efforts at the Topock site are subject to the regulatory authority of the California Department of Toxic Substances Control and the U.S. Department of the Interior. The California Department of Toxic Substances Control has approved the Utility's final remediation plan to contain and remediate the underground plume of hexavalent chromium, 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 expects to submit its final remedial design plan in 2014 for approval to begin construction of the groundwater treatment system. The Utility has implemented interim remediation measures, including a system of extraction wells and a treatment plant designed to prevent movement of the chromium plume toward the Colorado River.

The Utility's environmental remediation liability at September 30, 2013 reflects its best estimate of probable future costs associated with its final remediation plan. Future costs will depend on many factors, including the extent of work to be performed to implement the final groundwater remedy and the Utility's required time frame for remediation. As more information becomes known regarding these factors, the Utility's cost estimates and the assumptions on which they are based regarding the amount of liability incurred may be subject to further changes. Future changes in estimates or assumptions could have a material impact on PG&E Corporation's and the Utility's future financial condition and cash flows.

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 sites described above) if the extent of contamination or necessary remediation is greater than anticipated or if the other potentially responsible parties are not financially able to contribute to these costs, and could increase further if the Utility chooses to remediate beyond regulatory requirements. The Utility may incur actual costs in the future that are materially different than this estimate and such costs could have a material impact on PG&E Corporation's and the Utility's results of operations during the period in which they are recorded.

Tax Matters

The IRS is currently reviewing several matters pertaining to the 2008, 2010, 2011, and 2012 tax returns. The most significant of these matters relates to the repairs accounting method changes for the 2008, 2011, and 2012 tax returns.

The IRS has been working with the utility industry to provide guidance concerning the deductibility of repairs. PG&E Corporation and the Utility expect the IRS to issue guidance with respect to repairs made in the natural gas transmission and distribution businesses within the next six months. PG&E Corporation's and the Utility's unrecognized tax benefits may change significantly within the next 12 months depending on the guidance to be issued by the IRS and the resolution of the IRS audits related to the 2008, 2010, 2011, and 2012 tax returns. As of September 30, 2013, PG&E Corporation and the Utility believe that it is reasonably possible that unrecognized tax benefits will decrease by approximately $350 million within the next 12 months as a result of audit settlements.

There were no other significant developments to tax matters during the nine months ended September 30, 2013. (Refer to Note 9 of the Notes to the Consolidated Financial Statements in the 2012 Annual Report.)

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, 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 primarily by the CPUC and the FERC. 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. In addition, the NRC oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities. The Utility also is subject to the jurisdiction of other federal, state, and local governmental agencies.

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 the 2012 Annual Report.

Key Drivers and Summary of Changes in Net Income

For the quarter ended September 30, 2013, the Utility recorded a charge of $196 million to reflect increases in the forecasted capital expenditures expected to exceed the amount to be recovered through 2014 under the Utility's pipeline safety enhancement plan (referred to as the PSEP below). Additionally, in September 2013, the Utility settled the claims of substantially all of the remaining plaintiffs who sought compensation for personal injury, property damage, and other relief, following the San Bruno accident on September 9, 2010. The Utility recorded a charge of $110 million to reflect the outcome of these settlements and the Utility's estimated liability for remaining claims. (See "Natural Gas Matters" below.)

The following table is a summary reconciliation of the key changes, after-tax, in PG&E Corporation's income available for common shareholders and EPS for the three and nine months ended September 30, 2013 compared to the prior year (see "Results of Operations" below for additional information):

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions, except per share amounts)	Earnings	EPS (Diluted)	Earnings	EPS (Diluted)
Income Available for Common Shareholders - September 30, 2012	$361	$0.84	$829	$1.96
Growth in rate base earnings	22	0.05	65	0.15
Environmental-related costs	13	0.03	52	0.12
Reduction in authorized cost of capital (1)	(42)	(0.09)	(129)	(0.28)
Natural gas matters (2)	(209)	(0.46)	(58)	(0.11)
Impact of capital spending over authorized	(9)	(0.02)	(14)	(0.03)
Timing of incremental work	5	0.01	(9)	(0.02)
Gas transmission revenues	(1)	-	(7)	(0.02)
Increase in shares outstanding (3)	-	(0.04)	-	(0.11)
Other	21	0.04	(1)	(0.01)
Income Available for Common Shareholders - September 30, 2013	$161	$0.36	$728	$1.65

(1) Represents the impact of the 2013 Cost of Capital proceeding. See "Results of Operations" below for additional information.

(2) The Utility incurred higher charges related to natural gas matters for the three and nine months ended September 30, 2013, as compared to the same periods in 2012, resulting primarily from the charges described above, partially offset by lower legal and other expenses. See "Operating and Maintenance" below for additional information.

(3) Represents the impact of a higher number of shares outstanding at September 30, 2013, compared to the number of shares outstanding at September 30, 2012. PG&E Corporation issues shares to fund its equity contributions to the Utility to maintain the Utility's capital structure and fund operations, including expenses related to natural gas matters. This has no dollar impact on earnings.

Key Factors Affecting Results of Operations, Financial Condition, and Cash Flows

PG&E Corporation and the Utility believe that their results of operations, financial condition, and cash flows will continue to be materially affected by costs the Utility will incur to improve the safety and reliability of its natural gas operations, as well as by costs related to the ongoing investigations that commenced following the San Bruno accident. Several other factors have had, or are expected 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 Pending Investigations and Enforcement Matters. Three CPUC investigations are pending against the Utility related to its natural gas operations and the San Bruno accident. The SED has recommended that the CPUC impose what the SED characterizes as a penalty of $2.25 billion on the Utility, consisting of a $300 million fine payable to the State General Fund and $1.95 billion of non-recoverable costs. If the SED's penalty recommendation is adopted, the Utility estimates that its total unrecovered costs and fines related to natural gas transmission operations would be in excess of $4 billion. The CPUC ALJs are expected to issue one or more decisions on these investigations before the end of 2013. (See "Natural Gas Matters" below.) The CPUC and the SED also may impose fines or take enforcement action with respect to the Utility's self-reports of noncompliance with certain natural gas safety regulations and other potential enforcement matters described below. (See "CPUC Enforcement Matters" below.) PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows also may be materially affected by civil or criminal penalties or other remedies that may be imposed in connection with the ongoing criminal investigation of the San Bruno accident. (See "Criminal Investigation" below.)

- The Amount and Timing of the Utility's Financing Needs. PG&E Corporation contributes equity to the Utility as needed by the Utility to maintain its CPUC-authorized capital structure. The Utility has incurred significant expenses that are not recoverable through rates, which has increased the Utility's equity needs. For the nine months ended September 30, 2013, PG&E Corporation made equity contributions to the Utility of $835 million. Additional equity issued by PG&E Corporation to fund the Utility's future equity needs that arise due to the outcome of the pending investigations and unrecoverable costs incurred by the Utility is expected to have a material dilutive effect on PG&E Corporation's EPS. The Utility's financing needs also will be affected by other factors described in "Liquidity and Financial Resources" below. 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.

- The Timing and Outcome of Ratemaking Proceedings. The majority of the Utility's revenue requirements for the next several years will be determined by the outcomes of the 2014 GRC and the upcoming 2015 GT&S rate case. In the 2014 GRC, the Utility is seeking an increase in its 2014 revenue requirements of $1,160 million over the comparable revenues for 2013 that were previously authorized, as well as attrition increases for 2015 and 2016. The DRA has recommended that the CPUC approve a 2014 revenue requirement that is lower than the amount for 2013. The CPUC is currently scheduled to issue a decision in the 2014 GRC before the end of 2013. (See "2014 General Rate Case" below.) The Utility plans to file its 2015 GT&S rate case application with the CPUC in late 2013 to seek approval of increased revenue requirements to enable the Utility to recover its ongoing costs of providing natural gas transmission and storage service, including costs to continue performing work consistent with the PSEP as approved by the CPUC, beginning on January 1, 2015. The Utility's continued use of regulatory accounting of gas transmission and storage service depends on whether the CPUC authorizes sufficient revenues to recover its cost of service. (See "Gas Transmission and Storage Rate Case" below.) The outcome of these ratemaking proceedings can be affected by many factors, including general economic conditions, the level of customer rates, regulatory policies, and political considerations.

- The Ability of the Utility to Control Operating Costs and Capital Expenditures. Authorized revenues are primarily set based on forecasts and assumptions about the amount of operating costs and capital expenditures the Utility will incur in future periods. PG&E Corporation's and the Utility's net income is negatively affected when the authorized revenues are not sufficient for the Utility to recover the costs it actually incurs to provide utility services. In 2012, the Utility incurred expenses that were approximately $250 million higher than the level of authorized revenue requirements to improve the safety and reliability of its operations. The Utility forecasts that it will incur a comparable amount in 2013 that it will not recover in rates, as well as capital expenditures that exceed the current authorized levels, to make additional improvements. The Utility also may incur additional charges associated with work performed under the PSEP to reflect any future updates to its cost forecasts. (See "Natural Gas Matters" below.) The Utility's ability to recover pipeline safety-related costs beginning in 2015 also will be affected by the outcome of the 2015 GT&S rate case. Differences between the amount or timing of the Utility's actual costs and forecasted or authorized amounts may affect the Utility's ability to earn its authorized ROE.

CAUTIONARY LANGUAGE REGARDING FORWARD-LOOKING STATEMENTS

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

These forward-looking statements relate to, among other matters, estimated losses, including penalties and fines, associated with various investigations; forecasts of costs the Utility will incur to make safety and reliability improvements, including costs to perform work under the PSEP that the Utility will not recover through rates; forecasts of capital expenditures; estimates and assumptions used in critical accounting policies, including those relating to regulatory assets and liabilities, environmental remediation, litigation, third-party claims, and other liabilities; and the level of future equity or debt issuances. These statements are also identified by words such as “assume,” “expect,” “intend,” “forecast,” “plan,” “project,” “believe,” “estimate,” “predict,” “anticipate,” “may,” “should,” “w “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:

- when and how the pending investigations and enforcement matters related to the Utility’s natural gas system operating practices and the San Bruno accident are concluded, including the ultimate amount of fines the Utility will be required to pay to the State General Fund, the cost of any remedial actions the Utility may be ordered to perform, and the extent to which the Utility’s unrecovered and unrecoverable costs to perform work associated with its natural gas system are considered in reaching the final outcome;

- the outcome of the pending criminal investigation related to the San Bruno accident, including the ultimate amount of civil or criminal fines or penalties, if any, that may be imposed, and the impact of remedial measures such as the appointment of an independent monitor;

- whether PG&E Corporation and the Utility are able to repair the reputational harm that they have suffered, and may suffer in the future, due to the negative publicity surrounding the San Bruno accident, the related civil litigation, and the pending investigations, including any charge or finding of criminal liability;

- the timing and amount of insurance recoveries related to third-party liability incurred in connection with the San Bruno accident;

- the outcomes of current regulatory and ratemaking proceedings, such as the 2014 GRC and the pending TO rate cases; and the outcome of future regulatory and ratemaking proceedings, such as the 2015 GT&S rate case;

- the ultimate amount of costs the Utility incurs in the future that are not recovered through rates, including costs to perform incremental work to improve the safety and reliability of electric and natural gas operations;

- the outcome of future investigations or proceedings that may be commenced by the CPUC or other regulatory authorities relating to the Utility’s compliance with laws, rules, regulations, or orders applicable to the operation, inspection, and maintenance of its electric and gas facilities;

- the amount and timing of additional common stock issuances by PG&E Corporation, the proceeds of which are contributed as equity to maintain the Utility’s authorized capital structure as the Utility incurs charges and costs, including costs and fines associated with natural gas matters, 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 environmental compliance and remediation costs in rates or from other sources; and the ultimate amount of environmental remediation costs the Utility incurs but does not recover, such as the remediation costs associated with the Utility's natural gas compressor station site located near Hinkley, California;

- the impact of new legislation or NRC regulations, recommendations, policies, decisions, or orders relating to the operations, seismic design, security, safety, relicensing, or decommissioning of nuclear facilities, including the Utility's Diablo Canyon nuclear power plant, or relating to the storage of spent nuclear fuel, cooling water intake, or other issues; and whether the Utility obtains renewed operating licenses for the two nuclear operating units at Diablo Canyon;

- the impact of weather-related conditions or events, climate change, natural disasters, acts of terrorism, war, or vandalism (including cyber-attacks), and other events, 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 GHGs, and whether the Utility is able to continue recovering associated compliance costs, such as the cost of emission allowances and offsets under cap-and-trade regulations and the cost of renewable energy procurement;

- changes in customer demand for electricity and natural gas resulting from unanticipated population growth or decline in the Utility’s service area, general and regional economic and financial market conditions, the extent of municipalization of the Utility’s electric distribution facilities, changing levels of “direct access” customers who procure electricity from alternative energy providers, changing levels of customers who purchase electricity from governmental bodies that act as “community choice aggregators,” and the development of alternative energy technologies including self-generation and distributed generation technologies;

- the adequacy and price of electricity, natural gas, and nuclear fuel supplies; the extent to which the Utility can manage and respond to the volatility of energy commodity prices; the ability of the Utility and its counterparties to post or return collateral in connection with price risk management activities; and whether the Utility is able to recover timely its energy commodity costs through rates;

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

- the extent to which costs incurred in connection with third-party claims or litigation are not recoverable through insurance, rates, or from other third parties;

- the ability of PG&E Corporation and the Utility to access capital markets and other sources of debt and equity financing in a timely manner on acceptable terms;

- changes in credit ratings which could result in increased borrowing costs especially if PG&E Corporation or the Utility were to lose its investment grade credit ratings;

- the impact of federal or state laws or regulations, or their interpretation, on energy policy and the regulation of utilities and their holding companies, including how the CPUC interprets and enforces the financial and other conditions imposed on PG&E Corporation when it became the Utility’s holding company, and whether the outcome of proceedings and investigations relating to the Utility’s natural gas operations affects the Utility’s ability to make distributions to PG&E Corporation in the form of dividends or share repurchases; and, in turn, PG&E Corporation’s ability to pay dividends;

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

- the impact of changes in GAAP, standards, rules, or policies, including those related to regulatory accounting, and the impact of changes in their interpretation or application.

For more information about the significant risks that could affect the outcome of these forward-looking statements and PG&E Corporation’s and the Utility’s future financial condition, results of operations, and cash flows, see “Risk Factors” in the 2012 Annual Report and “Item 1.A. 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, 2013 and 2012:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2013	2012	2013	2012
Utility				
Electric operating revenues	$3,517	$3,321	$9,372	$9,022
Natural gas operating revenues	657	653	2,248	2,184
Total operating revenues	4,174	3,974	11,620	11,206
Cost of electricity	1,645	1,283	3,817	3,104
Cost of natural gas	131	118	656	593
Operating and maintenance	1,583	1,343	4,175	4,134
Depreciation, amortization, and decommissioning	523	617	1,542	1,807
Total operating expenses	3,882	3,361	10,190	9,638
Operating income	292	613	1,430	1,568
Interest income	2	2	6	5
Interest expense	(172)	(172)	(513)	(511)
Other income, net	20	19	66	64
Income before income taxes	142	462	989	1,126
Income tax (benefit) provision	(20)	122	261	328
Net income	162	340	728	798
Preferred stock dividend requirement	3	3	10	10
Income Available for Common Stock	$159	$337	$718	$788
PG&E Corporation (1)				
Operating revenues	$4,175	$3,976	$11,623	$11,210
Operating expenses	3,884	3,362	10,194	9,642
Operating income	291	614	1,429	1,568
Interest income	2	2	6	6
Interest expense	(179)	(178)	(532)	(528)
Other income, net	26	26	78	84
Income before income taxes	140	464	981	1,130
Income tax (benefit) provision	(24)	100	243	291
Net income	164	364	738	839
Preferred stock dividend requirement of subsidiary	3	3	10	10
Income Available for Common Shareholders	$161	$361	$728	$829

(1) Amounts for PG&E Corporation differ from comparable amounts for the Utility due primarily to PG&E Corporation's interest expense on long-term debt, other income from investments, and income taxes.

The following presents the Utility's operating results for the three and nine months ended September 30, 2013 and 2012.

Electric Operating Revenues

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2013	2012	2013	2012
Revenues excluding passed-through costs	$1,622	$1,616	$4,821	$4,763
Revenues for recovery of passed-through costs	1,895	1,705	4,551	4,259
Total electric operating revenues	$3,517	$3,321	$9,372	$9,022

The Utility's total electric operating revenues increased by $196 million, or 6%, and by $350 million, or 4%, in the three and nine months ended September 30, 2013, respectively, as compared to the same periods in 2012.

Electric operating revenues, excluding revenues intended to recover costs that are passed through to customers, remained flat in the three months ended September 30, 2013, and increased by $58 million in the nine months ended September 30, 2013, respectively, as compared to the same periods in 2012. Revenues increased by $49 million and $142 million for the three and nine month periods, respectively, as authorized in the 2011 GRC, and were partially offset by a decrease in revenues of $42 million and $125 million, respectively, due to the lower authorized ROE for 2013. The increase for the nine months ended September 30, 2013 also reflects $25 million of revenue authorized by the CPUC in 2013 for recovery of the Utility's incremental costs of responding to storms and wildfires from 2009 to 2011.

Revenues intended to recover costs that are passed through to customers and do not impact net income increased by $190 million and $292 million for the three and nine months ended September 30, 2013, respectively, as compared to the same periods in 2012. The change in the three and nine month periods was attributable to an increase in the cost of electricity of $362 million and $713 million, respectively (see "Cost of Electricity" below), offset by the absence of revenue of $141 million and $379 million, respectively, related to the energy recovery bonds that matured in late 2012.

The Utility's future electric operating revenues are expected to be impacted by revenues authorized in future rate cases. (See "Regulatory Matters" below.) Future electric operating revenues will also be impacted by the cost of electricity and other revenues intended to recover costs that are passed through to customers.

Cost of Electricity

The Utility's cost of electricity includes the costs of power purchased from third parties, transmission, fuel supplied to other facilities under power purchase agreements, realized gains and losses on price risk management activities, fuel used in its own generation facilities, and GHG emissions. (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 its electric transmission and distribution 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 amount and average cost of purchased power:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2013	2012	2013	2012
Cost of purchased power	$1,560	$1,214	$3,590	$2,896
Fuel used in own generation facilities	85	69	227	208
Total cost of electricity	$1,645	$1,283	$3,817	$3,104
Average cost of purchased power per kWh (1)	$0.101	$0.088	$0.092	$0.079
Total purchased power (in millions of kWh)	15,459	13,720	39,133	36,539

(1) Kilowatt-hour

The Utility's total cost of electricity increased by $362 million, or 28%, and by $713 million, or 23%, in the three and nine months ended September 30, 2013, respectively, as compared to the same periods in 2012, primarily due to higher costs to purchase renewable energy and increased spot prices for electricity and natural gas. Additionally, there was an increase in the volume of purchased power primarily due to increased renewable energy purchased.

Various factors will affect the Utility's future cost of electricity, including the market prices for electricity and natural gas, the availability of Utility-owned generation, and changes in customer demand. Additionally, the cost of electricity is expected to continue 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 and energy storage. (See "Environmental Matters" below.)

Natural Gas Operating Revenues

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2013	2012	2013	2012
Revenues excluding passed-through costs	$454	$433	$1,336	$1,320
Revenues for recovery of passed-through costs	203	220	912	864
Total natural gas operating revenues	$657	$653	$2,248	$2,184

The Utility's natural gas operating revenues remained flat in the three months ended September 30, 2013, and increased by $64 million, or 3% in the nine months ended September 30, 2013, as compared to the same periods in 2012.

Natural gas operating revenues, excluding revenues intended to recover costs that are passed through to customers, increased by $21 million and by $16 million in the three and nine months ended September 30, 2013, respectively, as compared to the same periods in 2012, primarily due to an increase in base revenues as authorized in the 2011 rate cases and under the Utility's pipeline safety enhancement plan that were offset by a decrease in revenues as a result of the 2013 Cost of Capital proceeding.

Revenues intended to recover costs that are passed through to customers and do not impact net income decreased by $17 million in the three months ended September 30, 2013, as compared to the same period in 2012, primarily due to lower transmission revenues that were partially offset by higher natural gas costs. (See "Cost of Natural Gas" below.)

Revenues intended to recover costs that are passed through to customers and do not impact net income increased by $48 million in the nine months ended September 30, 2013, as compared to the same period in 2012, primarily due to $63 million of higher natural gas costs and $36 million of revenues authorized by the CPUC (subject to refund) under the Utility's pipeline safety enhancement plan, with no similar revenues in the prior year (see "Natural Gas Matters" below). These increases for the nine months were partially offset by $40 million of lower transmission revenues, as compared to the same period in 2012.

The Utility's future natural gas operating revenues are expected to be impacted by the CPUC decision in the Utility's 2014 GRC and the 2015 GT&S rate case. (See "Regulatory Matters" below.) Future gas operating revenues will also be impacted by the cost of natural gas, natural gas throughput volume, and other factors.

Cost of Natural Gas

The Utility's cost of natural gas includes the costs of procurement, storage and transportation of natural gas, as well as 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 Utility's cost of natural gas excludes the cost of operating the Utility's gas transmission and distribution system, which is included in operating and maintenance expense in the 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)	2013	2012	2013	2012
Cost of natural gas sold	$96	$75	$533	$454
Transportation cost of natural gas sold	35	43	123	139
Total cost of natural gas	$131	$118	$656	$593
Average cost per Mcf (1) of natural gas sold	$3.43	$2.42	$3.14	$2.52
Total natural gas sold (in millions of Mcf)	28	31	170	180

(1) One thousand cubic feet

The Utility's total cost of natural gas increased $13 million, or 11%, and by $63 million, or 11%, in the three and nine months ended September 30, 2013, respectively, as compared to the same periods in 2012, primarily due to a higher average market price of natural gas.

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 costs will be affected by federal or state legislation or rules to regulate the GHG emissions from the Utility's natural gas transportation and distribution facilities and from natural gas consumed by the Utility's customers.

Operating and Maintenance

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

The Utility's operating and maintenance expenses increased by $240 million, or 18%, from $1,343 million in the three months ended September 30, 2012 to $1,583 million in the three months ended September 30, 2013. The increase was primarily due to $354 million of higher net costs associated with natural gas matters that are not recoverable through rates (see table below), including $196 million for disallowed PSEP capital expenditures, reflecting the increase in forecasted capital expenditures through 2014 that are expected to exceed the amount to be recovered, and $110 million for third-party claims related to the San Bruno accident. (See "Natural Gas Matters" below.)

The Utility's operating and maintenance expenses increased by $41 million, or 1%, from $4,134 million in the nine months ended September 30, 2012 to $4,175 million in the nine months ended September 30, 2013. The total increase was primarily due to $99 million of higher net costs associated with natural gas matters that are not recoverable through rates (see table below), including the charges described above. Operating and maintenance expense for 2013 also included $36 million of PSEP-related expenses that were authorized for recovery, subject to refund. (See "Natural Gas Matters" below.)

The following table provides a summary of the Utility's costs associated with natural gas matters that are not recoverable through rates:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2013	2012	2013	2012
Pipeline-related expenses (1) (2)	$113	$139	$249	$371
Disallowed capital	196	-	196	-
Third-party liability claims	110	-	110	80
Insurance recoveries	(25)	(99)	(70)	(135)
Contribution to City of San Bruno	-	-	-	70
Total natural gas matters	$394	$40	$485	$386

(1) For the three and nine months ended September 30, 2013, unrecoverable pipeline-related expenses included $50 million and $97 million, respectively, for work performed under the Utility's PSEP.
(2) The decrease in unrecoverable pipeline-related expenses reflects amounts that were authorized for recovery in the CPUC's December 2012 decision (as described above) as well as lower legal and other expenses in 2013.

The Utility forecasts that the total unrecoverable pipeline-related expenses in 2013 will range from $350 million to $450 million. Pipeline-related expenses include costs to validate safe operating pressures, conduct strength testing, and perform other work associated with the Utility's PSEP; costs related to the Utility's multi-year effort to identify and remove encroachments (e.g. building structures and vegetation overgrowth) from transmission pipeline rights-of-way, and costs to improve the integrity of transmission pipelines and to perform other gas-related work; and legal and other expenses. Additionally, in the three and nine months ended September 30, 2013, the Utility recorded a charge of $196 million for disallowed PSEP capital expenditures, reflecting the increase in forecasted capital expenditures through 2014 that are expected to exceed the amount to be recovered. The Utility could record additional charges if the CPUC does not approve the adjusted revenue requirements requested in the Utility's PSEP update application or if cost forecasts increase in the future. Disallowed costs would be recorded in the period incurred. (See "Natural Gas Matters – Pipeline Safety Enhancement Plan" below.)

For the three and nine months ended September 30, 2013, the Utility did not record any charges related to fines. Under the SED's penalty recommendation, the Utility estimates that its total past and future non-recoverable costs and fines related to natural gas transmission operations would be in excess of $4 billion. (See "Natural Gas Matters" below.) Future operating and maintenance expense will also be affected by any charges for civil or criminal penalties that may be imposed on the Utility. The Utility may incur costs to implement any remedial actions the CPUC may order the Utility to perform. (See "Natural Gas Matters" below.)

Depreciation, Amortization, and Decommissioning

The Utility's depreciation and amortization expense consists of depreciation and amortization on plant and regulatory assets, and decommissioning expenses associated with fossil fuel-fired generation facilities and nuclear power facilities. The Utility's depreciation, amortization, and decommissioning expenses decreased by $94 million, or 15%, and by $265 million, or 15%, in the three and nine months ended September 30, 2013, respectively, as compared to the same periods in 2012. The decrease in the three and nine months ended September 30, 2013 is primarily due to the absence of amortization expense of $137 million and $363 million, respectively, for the energy recovery bonds regulatory asset which fully amortized in 2012. The decreases in both periods were partially offset by the impact of capital additions.

The Utility's depreciation expense for future periods is expected to be affected as a result of changes in capital expenditures and the implementation of new depreciation rates as authorized by the CPUC in the future in the 2014

GRC and 2015 GT&S rate case. Future TO rate cases authorized by the FERC will also have an impact on depreciation rates.

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, 2013, as compared to the same periods in 2012.

Income Tax Provision

The Utility's income tax provision decreased by $142 million, or 116%, and $67 million, or 20%, in the three and nine months ended September 30, 2013, respectively, as compared to the same periods in 2012, primarily due to lower pretax income and higher state deductions and benefits described below.

The effective tax rates for the three months ended September 30, 2013 and 2012 were a benefit of 14% and expense of 26%, respectively. The effective tax rate decreased compared to 2012, primarilydue to higher state deductions and benefits received in 2013, including state deductible repairs due to a tax law change and benefits associated with a California research and development claim; and higher deductible software development costs.

The effective tax rates for the nine months ended September 30, 2013 and 2012 were 26% and 29%, respectively. The effective tax rate decreased compared to 2012, primarilydue to the state deductions and benefits mentioned above partially offset by the effect of regulatory treatment of fixed asset timing differences (which reverse over time) related to the cost of removal of fixed assets and decommissioning costs.

LIQUIDITY AND FINANCIAL RESOURCES

Overview

The Utility's ability to fund operations and make distributions to PG&E Corporation depends on the levels of its operating cash flows and access to the capital and credit markets. The levels of the Utility's cash flows fluctuate as a result of seasonal load, volatility in energy commodity costs, collateral requirements related to price risk management activities, the timing and effect of regulatory decisions, the timing and amount of long-term financings, and the timing and amount of tax payments or refunds, 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 consisting of 52% equity and 48% debt and preferred stock. The Utility relies on short-term debt, including commercial paper, to fund temporary financing needs. The CPUC authorizes the aggregate amount of long-term debt and short-term debt that the Utility may issue and authorizes the Utility to recover its related debt financing costs. The Utility has short-term borrowing authority of $4.0 billion, including $500 million that is restricted to certain contingencies.

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

PG&E Corporation and the Utility have approximately $1.3 billion of long-term debt maturing within the next 6 months. PG&E Corporation and the Utility plan to repay this debt with capital market financings.

The Utility's future equity needs will continue to be affected by costs that are not recoverable through rates, including costs related to natural gas matters. The Utility's equity needs would also increase to the extent it is required to pay fines or penalties in connection with the pending investigations. (See "Natural Gas Matters" below.) Further, given the Utility's significant ongoing capital expenditures, the Utility will continue to need equity contributions from PG&E Corporation to maintain its authorized capital structure.

PG&E Corporation's equity contributions to the Utility are funded primarily through common stock issuances. PG&E Corporation also may use draws under its revolving credit facility to occasionally fund equity contributions on an interim basis. PG&E Corporation's issuance of common stock to fund equity contributions to the Utility has been dilutive to PG&E Corporation's EPS to the extent that the equity contributions are used by the Utility to restore equity that has been depleted by unrecoverable costs and charges. Future issuances of common stock by PG&E Corporation could have a material dilutive effect on PG&E Corporation's EPS primarily depending upon the resolution of the CPUC's pending investigations and the ultimate amount of unrecoverable costs the Utility incurs.

PG&E Corporation's and the Utility's credit ratings may be affected by the ultimate outcome of the pending investigations related to natural gas matters and the San Bruno accident. PG&E Corporation's and the Utility's credit ratings may affect their access to the credit and capital markets and their respective financing costs in those markets. Credit rating downgrades may increase the cost of short-term borrowing, including the Utility's commercial paper, as well as the costs associated with their respective credit facilities, and long-term debt.

2013 Financings

Utility

In June 2013, the Utility issued $375 million principal amount of 3.25% Senior Notes due June 15, 2023 and $375 million principal amount of 4.60% Senior Notes due June 15, 2043. The proceeds were used to repurchase $461 million principal amount, net of $15 million of premiums and $6 million of accrued interest, of the Utility's $1.0 billion outstanding 4.80% Senior Notes due March 1, 2014, to repay a portion of outstanding commercial paper, and for general corporate purposes.

PG&E Corporation

In May 2013, PG&E Corporation entered into a new equity distribution agreement providing for the sale of PG&E Corporation common stock having an aggregate gross sales price of up to $400 million. As of September 30, 2013, PG&E Corporation sold common stock having an aggregate gross sales price of $150 million under this agreement. During the three and nine months ended September 30, 2013, PG&E Corporation paid commissions of $1 million, respectively, under this agreement.

During the nine months ended September 30, 2013, PG&E Corporation issued 18 million shares of its common stock for aggregate net cash proceeds of $724 million in the following transactions:

- 7 million shares were sold in an underwritten public offering for cash proceeds of $300 million, net of fees and commissions;
- 6 million shares that were issued for cash proceeds of $212 million under the PG&E Corporation 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans; and
- 5 million shares were sold for cash proceeds of $212 million, net of commissions paid of $2 million, under equity distribution agreements.

The proceeds from these sales were used for general corporate purposes, including the infusion of equity into the Utility. For the nine months ended September 30, 2013, PG&E Corporation made equity contributions to the Utility of $835 million. PG&E Corporation forecasts that it will need to continue to issue additional common stock to fund the Utility's equity needs.

Revolving Credit Facilities and Commercial Paper Program

In April 2013, PG&E Corporation and the Utility amended and restated their revolving credit facilities to extend their termination dates from May 31, 2016 to April 1, 2018. These agreements contain substantially similar terms as their original 2011 credit agreements.

The following table summarizes PG&E Corporation's and the Utility's outstanding borrowings at September 30, 2013:

(in millions)	Termination Date	Facility Limit		Letters of Credit Outstanding	Borrowings	Commercial Paper		Facility Availability	
PG&E Corporation	April 2018	$300	(1)	$-	$260	$-		$40	
Utility	April 2018	3,000	(2)	91	-	693	(3)	2,216	(3)

Total revolving credit facilities	$3,300	$91	$260	$693	$2,256

(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, 2013, the average outstanding borrowings under PG&E Corporation's revolving credit facility were $199 million and the maximum outstanding balance during the period was $260 million. For the nine months ended September 30, 2013, the Utility's average outstanding commercial paper balance was $528 million and the maximum outstanding balance during the period was $1.0 billion. The Utility has not borrowed under its credit facility during 2013.

At September 30, 2013, PG&E Corporation and the Utility were in compliance with all covenants under their respective revolving credit facilities.

Dividends

In September 2013, the Board of Directors of PG&E Corporation declared quarterly dividends of $0.455 per share, totaling $204 million, of which $199 million was paid on October 15, 2013 to shareholders of record on September 30, 2013.

In September 2013, the Board of Directors of the Utility declared dividends on its outstanding series of preferred stock, payable on November 15, 2013, to shareholders of record on October 31, 2013.

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, 2013 and 2012 were as follows:

(in millions)	2013	2012
Net income	$728	$798
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	1,542	1,807
Allowance for equity funds used during construction	(78)	(79)
Deferred income taxes and tax credits, net	545	633
PSEP disallowed capital expenditures	196	-
Other	231	189
Net effect of changes in operating assets and liabilities	(338)	157
Net cash provided by operating activities	$2,826	$3,505

During 2013, net cash provided by operating activities decreased by $679 million compared to 2012. This decrease was driven by fluctuations in activities within the normal course of business such as the timing and amount of payments, including $86 million of tax payments due to audit settlements in 2013 compared to $174 million in tax refunds during 2012.

Future cash flow from operating activities will be affected by various factors, including:

- the timing and amount of tax payments, tax refunds, net collateral payments, and interest payments;
- the timing and amount of payments to third parties in connection with the San Bruno accident and related insurance recoveries;
- the timing and amount of fines or penalties that may be imposed, as well as any costs associated with remedial actions the Utility may be required to implement;
- the anticipated higher operating and maintenance costs associated with the Utility's natural gas and electric operations (see "Operating and Maintenance" above and "Natural Gas Matters" below); and
- 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).

Investing Activities

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

The Utility's cash flows from investing activities for the nine months ended September 30, 2013 and 2012 were as follows:

(in millions)	2013	2012
Capital expenditures	$(3,881)	$(3,361)
Decrease (increase) in restricted cash	29	(38)
Proceeds from sales and maturities of nuclear decommissioning trust investments	1,152	903
Purchases of nuclear decommissioning trust investments	(1,150)	(964)
Other	14	14
Net cash used in investing activities	$(3,836)	$(3,446)

Net cash used in investing activities increased by $390 million in 2013 compared to 2012 primarily due to higher capital expenditures.

Future cash flows used in investing activities are largely dependent on the timing and amount of capital expenditures. The Utility forecasts that capital expenditures will total approximately $5.1 billion in 2013, including expenditures related to its pipeline safety enhancement plan. For more information about the types of capital investments made by the Utility, see “Capital Expenditures” in the 2012 Annual Report.

Financing Activities

The Utility’s cash flows from financing activities for the nine months ended September 30, 2013 and 2012 were as follows:

(in millions)	2013	2012
Net issuance (repayments) of commercial paper, net of discount of $1 and $3 at respective dates	$322	$(1,247)
Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $9 and $10 at respective dates	741	1,140
Long-term debt matured or repurchased	(461)	(50)
Energy recovery bonds matured	-	(313)
Preferred stock dividends paid	(10)	(10)
Common stock dividends paid	(537)	(537)
Equity contribution	835	715
Other	(14)	25
Net cash provided by (used in) financing activities	$876	$(277)

In 2013, net cash provided by financing activities increased by $1.2 billion compared to the same period in 2012. Cash provided by or used in financing activities is driven by the Utility’s financing needs, which depend on the level of cash provided by or used in operating activities, the level of cash provided by or used in investing activities, the conditions in the capital markets, and the maturity date of existing debt instruments. The Utility generally utilizes long-term senior unsecured debt issuances and equity contributions from PG&E Corporation to maintain its CPUC-authorized capital structure, and relies on short-term debt to fund temporary financing needs.

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 2012 Annual Report and "Liquidity and Financial Resources" above.)

NATURAL GAS MATTERS

Since the San Bruno accident, PG&E Corporation and the Utility have incurred total cumulative charges of approximately $2.3 billion related to natural gas matters that are not recoverable through rates, as shown in the following table:

(in millions)	Cumulative December 31, 2012	Nine Months Ended September 30, 2013	Cumulative September 30, 2013
Pipeline-related expenses (1)	$1,023	$249	$1,272
Disallowed capital (2)	353	196	549
Accrued fines (3)	217	-	217
Third-party liability claims (4)	455	110	565
Insurance recoveries (4)	(284)	(70)	(354)
Contribution to City of San Bruno	70	-	70
Total natural gas matters	$1,834	$485	$2,319

(1) Cumulative costs through September 2013 include PSEP-related expenses of approximately $700 million and other gas safety-related work of $300 million.
(2) See "Pipeline Safety Enhancement Plan" below.
(3) See "Pending CPUC Investigations" below. Amount includes $17 million penalty that was paid in 2012.
(4) See "Third-Party Claims" below.

As described below, there are three pending CPUC investigations against the Utility. As part of those proceedings, the SED has recommended that the CPUC impose what the SED characterizes as a penalty of $2.25 billion on the Utility, allocated as follows: (1) $300 million as a fine to the State General Fund, (2) $435 million for a portion of PSEP costs that were previously disallowed by the CPUC and funded by shareholders, and (3) $1.515 billion to perform PSEP work that was previously approved by the CPUC, implement operational remedies, and for future PSEP costs. If the SED's penalty recommendation is adopted by the CPUC, the Utility estimates that its total unrecovered costs and fines related to natural gas transmission operations would be in excess of $4 billion.

Pipeline Safety Enhancement Plan

The Utility's pipeline safety enhancement plan is a multi-year program to modernize and upgrade its natural gas transmission system. In December 2012, the CPUC approved most of the projects proposed in the PSEP but disallowed the Utility's request for rate recovery of a significant portion of costs the Utility forecasted it would incur through 2014. The CPUC authorized the Utility to recover costs, subject to the adopted capital and expense amounts, for activities including pipeline strength testing, pipeline replacement, in-line inspection, and the installation of automated valves. The CPUC prohibited the Utility from recovering the costs of pressure testing pipeline placed into service after January 1, 1956 for which the Utility is unable to produce pressure test records. The CPUC ordered the Utility to file an update PSEP application after the Utility completes its search and review of records relating to pipeline pressure validation for all 6,750 miles of the Utility's natural gas transmission pipelines.

On October 29, 2013, the Utility submitted its update application to present the results of its completed records search and review and to request approval of adjusted revenue requirements. Based on the information obtained through the records search and review, the Utility has proposed to change the scope and prioritization of PSEP work, including deferring some projects to after 2014 and accelerating other projects. The Utility has proposed net reductions to authorized costs for both its strength testing program (to test 658 miles rather than 783 miles) and its pipeline replacement program (to replace 143 miles rather than 186 miles). In August 2013, in anticipation of the Utility's update application, TURN and the CPUC's DRA requested the assigned ALJ for an order limiting the scope of the revenue requirement changes that the Utility could request in the update application to only those changes resulting from the records search and subsequent pressure validation based on those records, which could result in a disallowance of costs associated with the acceleration of projects. The ALJ has not yet addressed their request and it is uncertain how the information presented in the Utility's update application about accelerating or changing the scope of PSEP projects will be considered. Under the CPUC's procedural rules, intervening parties may file protests and responses to the Utility's application no later than December 2, 2013. The Utility has requested that the CPUC issue a final decision by August 2014 to approve the revised scope of PSEP projects and the net reduction in authorized costs.

Based on the proposed changes in the scope of PSEP projects through 2014, the Utility forecasts that total unrecoverable costs to complete this work will significantly exceed the amount previously forecasted primarily due to higher anticipated unit costs to replace pipeline segments. As a result, for the three months ended September 30, 2013, the Utility recorded a charge of $196 million, reflecting the increase in forecasted capital expenditures through 2014 that are expected to exceed the amount to be recovered. At September 30, 2013, the Utility has recorded cumulative charges of $549 million for disallowed PSEP-related capital expenditures, including $353 million recorded at December 31, 2012. Disallowed expenses are charged to net income in the period incurred. The Utility has incurred cumulative PSEP-related expenses of approximately $700 million through September 30, 2013 that are not recoverable through rates.

At September 30, 2013, capitalized PSEP costs of approximately $170 million are included in Property, Plant, and Equipment on the Condensed Consolidated Balance Sheets. The Utility could record additional charges if the CPUC does not approve the adjusted revenue requirements requested in the Utility's PSEP update application or if cost forecasts increase in the future. The CPUC also could make ratemaking adjustments to recovery of PSEP costs in connection with the pending CPUC investigations discussed below. The Utility's ability to recover pipeline safety costs beginning in 2015 also will be affected by the outcome of the 2015 GT&S rate case. See "2015 GT&S rate case" in "Regulatory Matters" below.

Pending CPUC Investigations

There are three CPUC investigative enforcement proceedings pending against the Utility that relate to (1) the Utility's safety recordkeeping for its natural gas transmission system, (2) the Utility's operation of its natural gas transmission pipeline system in or near locations of higher population density, and (3) the Utility's pipeline installation, integrity management, recordkeeping and other operational practices, and other events or courses of conduct, that could have led to or contributed to the San Bruno accident. Evidentiary hearings and briefing have been completed in each of these investigations.

The SED has recommended that the CPUC impose what the SED characterizes as a penalty of $2.25 billion on the Utility, allocated as follows: (1) $300 million as a fine to the State General Fund, (2) $435 million for a portion of PSEP costs that were previously disallowed by the CPUC and funded by shareholders, and (3) $1.515 billion to perform PSEP work that was previously approved by the CPUC, implement operational remedies, and for future PSEP costs. Other parties, including the City of San Bruno, TURN, the CPUC's DRA, and the City and County of San Francisco, have recommended total penalties of at least $2.25 billion, including fines payable to the State General Fund of differing amounts. The City of San Bruno also recommended that the Utility provide $150 million for a Peninsula Emergency Response Consortium, spend $100 million ($5 million per year for 20 years) to fund an independent advocacy trust (the California Pipeline Safety Trust), and provide funding for an independent monitor to oversee the implementation of the recommended remedial operational measures. TURN also recommended that the Utility bear expenses of $50 million to implement remedial measures and to pay for an independent monitor.

The record for the proceedings was closed on October 15, 2013. The CPUC's rules call for the CPUC ALJs to issue one or more presiding officers' decisions within 60 days of this date. The decisions will become the final decisions of the CPUC 30 days after issuance unless the Utility or another party files an appeal with the CPUC, or a CPUC commissioner requests that the CPUC review the decision, within such time. If an appeal or review request is filed, other parties have 15 days to provide comments but the CPUC could act before considering any comments.

At September 30, 2013 and December 31, 2012, PG&E Corporation's and the Utility's Condensed Consolidated Balance Sheets included an accrual of $200 million in other current liabilities for the minimum amount of fines deemed probable that the Utility will pay to the State General Fund. The Utility is unable to make a better estimate due to the many variables that could affect the final outcome, including how the total number and duration of violations will be determined; how the various penalty recommendations made by the SED and other parties will be considered; how the financial and tax impact of unrecoverable costs the Utility has incurred, and will continue to incur, to improve the safety and reliability of its pipeline system, will be considered; whether the Utility's costs to perform any required remedial actions will be considered; and how the CPUC responds to public pressure. Future changes in these estimates or the assumptions on which they are based could have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows. The CPUC may impose fines on the Utility that are materially higher than the amount accrued and may disallow PSEP costs that were previously authorized for recovery or other future costs. Disallowed costs would be charged to net income in the period incurred.

Other CPUC Enforcement Matters

In addition to the investigations that are pending against the Utility related to its natural gas operations and the San Bruno accident, the CPUC and/or SED are also considering the following matters. PG&E Corporation and the Utility are unable to estimate the amount or range of reasonably possible losses that may be incurred in connection with these matters.

Gas Safety Citation Program

California gas corporations are required to provide notice to the SED of any self-identified or self-corrected violations of certain state and federal regulations related to the safety of natural gas facilities and the corporations' natural gas operating practices. The SED is authorized to issue citations and impose fines for violations of certain state and federal regulations. In September 2013, the SED published a document explaining the internal procedures the SED staff intends to follow in assessing gas safety violations and determining appropriate enforcement action. (Also see "Safety Enforcement Legislation" in "Regulatory Matters" below.) The SED can consider several factors in exercising its discretion to impose fines or take other enforcement action based on the totality of the circumstances. Such factors include how the SED assesses the severity of the safety risk associated with each violation; how the SED determines the number of violations; how the SED determines the duration of the violations; how the SED considers other factors such as whether the violation was self-reported, and whether any corrective actions were taken. The SED's internal procedures also include a schedule of potential fine amounts that vary based on the severity of the safety risk posed by the violation.

In October 2013, the SED issued a citation related to one of the Utility's self-reports and imposed a fine of $140,000. The Utility has filed 58 self-reports with the SED, plus additional follow-up reports, that the SED has not yet addressed. The SED could issue additional citations and impose fines associated with these self-reports.

Orders to Show Cause

On August 19, 2013, the CPUC issued two OSCs related to a document submitted by the Utility on July 3, 2013 as "errata" to correct information about some segments in Lines 101 and 147 (two of the Utility's natural gas transmission pipelines that serve the San Francisco peninsula) that had been previously provided to the CPUC in October 2011 to allow the Utility to restore operating pressure on these pipelines. The first OSC directed the Utility to show why all orders issued by the CPUC to authorize increased operating pressure on the Utility's gas transmission pipelines should not be immediately suspended pending competent demonstration that the Utility's natural gas system records are reliable. It is uncertain when the CPUC will issue a decision on the first OSC. The second OSC ordered the Utility to show why it should not be penalized for violating CPUC rules that prohibit any person from misleading the CPUC, in connection with the errata submission. Among other recommendations submitted by intervening parties related to the second OSC, the DRA and TURN have recommended that the CPUC impose penalties of $12.7 million on the Utility for the errata submission. The CPUC is expected to issue a decision on the second OSC before the end of 2013. The CPUC could impose penalties on the Utility or take other enforcement action in connection with the OSCs.

Natural Gas Transmission Pipeline Rights-of-Way

In 2012, the Utility also notified the CPUC and the SED that the Utility is undertaking a system-wide effort to survey its transmission pipelines and identify and remove encroachments (such as building structures and vegetation overgrowth) from pipeline rights-of-way over a multi-year period. The SED could impose penalties on the Utility or take other enforcement action in connection with this matter.

Criminal Investigation

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

Third-Party Claims

In September 2013, the Utility agreed to settle the claims of substantially all of the remaining plaintiffs who sought compensation for personal injury and property damage, and other relief, including punitive damages, following the San Bruno accident. Approximately 165 lawsuits on behalf of approximately 525 plaintiffs have been filed against the Utility. For the three and nine months ended September 30, 2013, the Utility recorded a charge of $110 million to reflect its best estimate of probable loss for settlements reached in September 2013 and remaining third-party claims for personal injury, property damage, and damage to infrastructure, including claims by government entities. At September 30, 2013, the Utility has recorded cumulative charges of $565 million for third-party claims related to the San Bruno accident and has made cumulative payments of $389 million for settlements.

Through September 30, 2013, the Utility has recognized cumulative insurance recoveries of $354 million for third-party claims and related legal expenses. (The Utility has incurred cumulative legal expenses of $84 million in addition to the $565 million charges above). Insurance recoveries for the three and nine months ended September 30, 2013 were $25 million and $70 million, respectively. These amounts were recorded as a reduction to operating and maintenance expense in PG&E Corporation's and the Utility's Condensed Consolidated Statements of Income. Although the Utility believes that a significant portion of costs incurred for third-party claims (and associated legal expenses) relating to the San Bruno accident will ultimately be recovered through its insurance, it is unable to predict the amount and timing of additional insurance recoveries. (See Note 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. The plaintiffs allege that PG&E Corporation and the Utility engaged in unfair business practices in violation of California state law. The plaintiffs seek restitution and disgorgement, as well as compensatory and punitive damages.

PG&E Corporation and the Utility contest the plaintiffs' allegations. On May 23, 2013, the court granted PG&E Corporation's and the Utility's request to dismiss the complaint on the grounds that the CPUC has exclusive jurisdiction to adjudicate the issues raised by the plaintiffs' allegations. The plaintiffs have appealed the court's ruling to the California Court of Appeal. PG&E Corporation and the Utility are unable to estimate the amount or range of reasonably possible losses, if any, that may be incurred in connection with this matter.

Other Pending Lawsuits and Claims

At September 30, 2013, there were also four purported shareholder derivative lawsuits outstanding against PG&E Corporation and the Utility seeking recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims. Three of these lawsuits are pending in the San Mateo County Superior Court. Although the proceedings have been stayed until further order of the court pending the resolution of the remaining third-party claims, the judge has lifted the stay for the limited purpose of permitting the derivative plaintiffs to obtain the information necessary for them to prepare, file, and serve a consolidated, or master, complaint. A case management conference is scheduled for January 21, 2014. The remaining purported shareholder derivative lawsuit, filed in the U.S. District Court for the Northern District of California, remains stayed pending the resolution of the lawsuits pending in the state Superior Court. PG&E Corporation and the Utility are uncertain when and how these derivative lawsuits will be resolved.

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

PG&E Corporation and the Utility are uncertain when and how the above lawsuits will be resolved.

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 financial condition, results of operations, and cash flows. Significant regulatory developments that have occurred since the 2012 Annual Report was filed with the SEC are discussed below.

2014 General Rate Case

In the GRC, the CPUC will determine the annual amount of revenue requirements that the Utility is authorized to collect through rates from 2014 through 2016 to recover anticipated costs associated with electric generation operations, and electric and natural gas distribution operations, and to provide the Utility an opportunity to earn its authorized ROE on related capital expenditures. The CPUC has concluded evidentiary hearings and briefing in the 2014 GRC and the Utility is now waiting for the CPUC to issue a proposed decision.

The Utility is seeking an increase in its 2014 revenue requirements of $1,160 million over the comparable revenues for 2013 that were previously authorized by the CPUC, for a requested total revenue requirement of $7.8 billion. The Utility's request is based on detailed expense and capital forecasts for 2014. The Utility also has requested that the CPUC authorize attrition increases in 2015 and 2016 of $436 million and $486 million, respectively. The DRA recommends that the Utility's 2014 revenue requirements be reduced by $125 million from amounts authorized in 2013, approximately $1,285 million lower than the Utility's current forecast. The DRA also has recommended attrition increases of $169 million for 2015 and $160 million for 2016. The following table compares the Utility's updated forecasted annual increases for 2014 through 2016 with the DRA's recommended amounts:

	Increase (Decrease) to Revenue Requirements		Difference Between
(in millions)	Utility's Forecast (1)	DRA's Recommendation	Utility and DRA
2014	$1,160	$ (125)	$(1,285)
2015 attrition	436	169	(267)
2016 attrition	486	160	(326)

(1) Amounts reflect the Utility's authorized cost of capital for 2013 and other adjustments to amounts requested in the Utility's November 2012 application as a result of revised calculations.

The DRA's recommendation reflects reductions across all lines of business represented in the GRC. The DRA has recommended that the CPUC moderate impacts on customer rates by reducing the amount of depreciation recovered through rates throughout the GRC period to approximately $160 million as compared to the $492 million increase supported by the Utility's depreciation rate study. The DRA has also recommended that the Utility's capital expenditures be reduced by $1.0 billion in 2014, as compared to the Utility's forecast of average annual capital expenditures of approximately $4.0 billion from 2014 to 2016.

Twelve other parties, including TURN, have also submitted recommendations in the 2014 GRC.TURN's recommendation reflects reductions across most lines of business represented in the GRC, including significant reductions to the amount of depreciation recovered through rates. In addition, on May 17, 2013, the SED submitted the reports of consultants it engaged to evaluate the Utility's use of safety risk assessment and risk mitigation measures in developing the Utility's forecast. Overall, the reports found that most of the Utility's forecasted projects and costs were generally reasonable but criticized the Utility's level of risk analysis underlying the forecast.

The Utility believes that the substantial revenue requirement reductions recommended by DRA and TURN could undermine the Utility's efforts to improve customer safety, reliability and service over the next three years. The Utility also believes that the recommendations fail to consider that the Utility's currently authorized revenue requirements do not provide sufficient revenue to allow the Utility to recover the Utility's actual costs to improve the safety and reliability of its operations. In 2012, the Utility incurred expenses that were approximately $250 million higher than the level of authorized revenue requirements and the Utility forecasts that it will incur a comparable amount in 2013. In addition, the Utility forecasts that capital expenditures for additional improvements will exceed currently authorized levels. (See "Operating and Maintenance" above.)

The CPUC's procedural schedule contemplates a proposed decision to be issued by November 19, 2013 and a final decision to be issued by December 19, 2013. The CPUC has authorized the Utility's revenue requirement changes to become effective as of January 1, 2014, even if the final decision is issued after that date.

Electric Transmission Owner Rate Cases

The Utility has two TO rate cases pending at the FERC. With respect to the TO rate case that was filed in September 2012, the Utility, the FERC Trial Staff and all active intervening parties reached a settlement that has been submitted to the FERC for approval. The settlement, if approved, will increase the annual retail revenue requirement from $934 million to $1,017 million effective as of May 1, 2013. In future periods, the Utility will refund to customers the difference between revenues collected at the higher as-filed rates and the rates proposed in the settlement. It is uncertain when the FERC will act on the settlement.

On September 24, 2013, the FERC accepted the Utility's TO rate case that the Utility filed on July 24, 2013, making the proposed rates effective October 1, 2013, subject to refund pending a final decision by the FERC. The Utility requested a retail revenue requirement of $1,072 million and an ROE of 10.9%. The proposed rates represent a $30 million reduction as compared to the revenue requirements that have been in effect since May 1, 2013 (subject to refund) and a $55 million increase to the revenue requirements described in the preceding paragraph. Hearings are currently being held in abeyance while settlement discussions are held.

2015 Gas Transmission and Storage Rate Case

The Utility plans to file its 2015 GT&S rate case application before the end of 2013 to request that the CPUC authorize an increase in revenue requirements beginning on January 1, 2015 for the Utility's ongoing costs of providing natural gas transmission and storage service, including costs to continue performing work consistent with the PSEP as approved by the CPUC, and financing costs. The Utility has incurred (and forecasts to continue to incur) costs that are substantially higher than amounts authorized by the CPUC in the Utility's last GT&S and PSEP rate cases, as the Utility works to improve the safety and reliability of its natural gas transmission operations. (See "Natural Gas Matters" above.) The CPUC's decision approving the PSEP authorizes the Utility to recover PSEP-related revenue requirements only through 2014. The CPUC's decision in the Utility's last GT&S rate case authorized revenue requirements through 2014 with an automatic 2% increase in rates on January 1, 2015 which will remain in effect until the CPUC issues a decision in the 2015 GT&S rate case. If the CPUC issued its decision after January 1, 2015, the revenue requirement adjustments would not be retroactive to January 1, 2015, unless ordered otherwise by the CPUC. If the Utility's spending levels for GT&S services and PSEP work were to remain at the levels currently forecast, the automatic increase on January 1, 2015 would be insufficient for the Utility to recover its ongoing costs of service. The Utility's continued use of regulatory accounting (which enables it to account for the effects of regulation, including recording regulatory assets and liabilities) for gas transmission and storage service depends on its ability to recover its cost of service. The timing of expense (or gain) recognition differs under GAAP accounting as compared to regulatory accounting. If the Utility was unable to continue using regulatory accounting, the differences in the timing of expense (or gain) recognition could affect the Utility's financial results.

Under the CPUC's procedural rules, intervening parties may file protests and responses to the Utility's application. After the Utility files its reply, a prehearing conference would be held to set the procedural schedule, including the dates for evidentiary hearings. The timing and outcome of the 2015 GT&S rate case are uncertain.

Oakley Generation Facility

In December 2012, the CPUC approved an amended purchase and sale agreement between the Utility and a third-party developer that provides for the construction of a 586-megawatt natural gas-fired facility in Oakley, California. The CPUC authorized the Utility to recover the purchase price through rates. On April 18, 2013, the CPUC denied various applications for rehearing that had been filed with respect to the CPUC's December 2012 decision. The CPUC's denial of the rehearing applications has been appealed to the California Court of Appeal. On October 28, 2013, the California Court of Appeal issued a ruling granting review of the CPUC's decision. The Utility is uncertain when the court will issue a decision on these appeals and how the court's decision will impact the ultimate development and construction of the Oakley facility.

Diablo Canyon Nuclear Power Plant

The Utility has filed an application with the NRC to renew the operating licenses for the two operating units at Diablo Canyon. (The current licenses expire in 2024 and 2025.) In May 2011, after the earthquake and tsunami that caused significant damage to the Fukushima-Dai-ichi nuclear facilities in Japan, the NRC granted the Utility's request to delay processing the Utility's application until certain advanced seismic studies were completed by the Utility. After the Utility completes its seismic studies as anticipated by June 2014, the Utility will determine whether and when it will request the NRC to resume the relicensing proceeding. In order for the NRC to issue renewed operating licenses, the California Coastal Commission must determine that license renewal is consistent with federal and state coastal laws. The disposition of the Utility's relicensing application also will be affected by the terms and timing of the NRC's "waste confidence" decision regarding the environmental impacts of the storage of spent nuclear fuel which is not expected to be issued before September 2014. The NRC has stated that it will not take action in licensing or re-licensing proceedings until it issues a new "waste confidence decision."

The CPUC is considering the Utility's December 2012 application to recover estimated costs to decommission the Utility's nuclear facilities at Diablo Canyon and the retired nuclear facility Humboldt Bay Power Plant Unit 3. The Utility files an application with the CPUC every three years requesting approval of the Utility's estimated decommissioning costs and authorization to recover those costs through rates. As discussed in the 2012 Annual Report, the estimated discounted cost to decommission Diablo Canyon and Humboldt Bay increased by approximately $960 million and $480 million, respectively. The CPUC bifurcated the proceeding to allow for the decommissioning cost estimate associated with Humboldt Bay to be addressed first and all other matters (including the Diablo Canyon decommissioning cost estimate and all rate-related issues) to be addressed in a second phase. The CPUC is scheduled to issue a proposed decision regarding the decommissioning cost estimate associated with Humboldt Bay in November 2013 with a final decision anticipated in January 2014. The Utility anticipates the CPUC will issue a decision in the second phase during the first quarter of 2014.

Safety Enforcement Legislation

On October 5, 2013, the California Governor signed Senate Bill 291 which requires the CPUC to develop a safety enforcement program that authorizes CPUC staff to issue citations for safety violations and assess fines subject to a CPUC-approved limit. The safety programs also must allow the CPUC staff to consider mitigating and aggravating factors in exercising enforcement authority. The CPUC is required to implement the safety enforcement program for gas corporations by July 1, 2014 and for electric corporations by January 1, 2015. The Utility expects that the safety programs to be developed by the CPUC to comply with the new legislation will be substantially similar to the SED's new internal procedures applicable to the gas safety citation program. See "Natural Gas Matters – Other CPUC Enforcement Matters" above.

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 2012 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.

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. On July 17, 2013, the Regional Board certified a final environmental report evaluating the Utility's proposed remedial methods to contain and remediate the underground plume of hexavalent chromium and the potential environmental impacts. The Regional Board is expected to issue waste discharge permits in 2014 to allow for continued treatment of hexavalent chromium and issue a final clean-up order in 2015.

The Utility has implemented interim remediation measures to reduce the mass of the chromium plume, to monitor and control movement of the plume, and provide replacement water to affected residents. As of September 30, 2013, approximately 350 residential households located near the plume boundary were covered by the Utility's whole house water replacement program and the majority have opted to accept the Utility's offer to purchase their properties. The Utility is required to maintain and operate the program 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. The State of California recently proposed draft regulations for hexavalent chromium and is expected to issue a final standard in 2014.

At September 30, 2013 and December 31, 2012, $197 million and $226 million, respectively, were accrued in PG&E Corporation's and the Utility's Condensed Consolidated Balance Sheets for estimated undiscounted future remediation costs associated with the Hinkley site. Remediation costs for the Hinkley site are not recovered from customers through rates. Future costs will depend on many factors, including the levels of hexavalent chromium the Utility is required to use as the standard for remediation, the required time period by which those standards must be met, the extent of the chromium plume boundary, and adoption of a final drinking water standard by the State of California. As more information becomes known regarding these factors, the Utility's cost estimates and the assumptions on which they are based regarding the amount of liability incurred may be subject to further changes. Future changes in estimates or assumptions may have a material impact on PG&E Corporation's and the Utility's future financial condition, results of operations, and cash flows.

GHG Cap-and-Trade

California Assembly Bill 32 requires the gradual reduction of state-wide GHG emissions to the 1990 level by 2020. The CARB is the state agency charged with adopting regulations to implement and enforce AB 32. The CARB has established a state-wide, comprehensive "cap-and-trade" program that sets a gradually declining limit (or "cap") on the amount of GHGs that may be emitted by the major sources of GHG emissions each year. The cap-and-trade program's first two-year compliance period, which began on January 1, 2013, applies to the electricity generation and large industrial sectors. The next compliance period, from January 1, 2015 through December 31, 2017, will be expanded to include the natural gas supply and transportation sectors, effectively covering all the capped sectors until 2020.

During each year of the program, the CARB will issue emission allowances (i.e., the rights to emit GHGs) equal to the amount of GHG emissions allowed for that year. Emitters can obtain allowances from the CARB at quarterly auctions held by the CARB or from third parties or exchanges in the market for trading GHG allowances. The CARB will also allocate a fixed number of allowances (which will decrease each year) for free to regulated electric distribution utilities, including the Utility, for the benefit of their electricity customers. The utilities are required to consign their allowances for auction by the CARB. The CPUC has ordered the utilities to allocate their auction revenues among certain classes of their customers in accordance with existing state law. Although the CPUC has previously authorized the utilities to recover their GHG compliance costs through rates, the recovery of these costs has been deferred until the CPUC adopts a final revenue allocation methodology. A final methodology is expected to be issued before the end of 2013.

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

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 of the Notes to the Condensed Consolidated Financial Statements (PG&E Corporation's tax equity financing agreements) and Note 15 of the Notes to the Consolidated Financial Statements in the 2012 Annual Report (the Utility's commodity purchase agreements).

RISK MANAGEMENT ACTIVITIES

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

The Utility actively manages market risk through risk management programs designed to support business objectives, discourage unauthorized risk-taking, reduce commodity cost volatility, and manage cash flows. The Utility uses derivative instruments only for non-trading purposes (i.e., risk mitigation) and not for speculative purposes. The Utility's risk management activities include the use of energy and financial instruments such as forward contracts, futures, swaps, options, and other instruments and agreements, most of which are accounted for as derivative instruments. Some contracts are accounted for as leases. These activities are discussed in detail in the 2012 Annual Report. There were no significant developments to the Utility and PG&E Corporation's risk management activities during the nine months ended September 30, 2013.

CRITICAL ACCOUNTING POLICIES

The preparation of the Condensed Consolidated Financial Statements in accordance with U.S. GAAP 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 benefits 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 2012 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, 2013, 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 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 Securities Exchange Act of 1934 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, 2013 that have materially affected, or are reasonably likely to materially affect, PG&E Corporation's or the Utility's internal control over financial reporting.

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 Nuclear Power Plant

In June 2013, the United States EPA and environmental group Riverkeeper agreed to extend until November 4, 2013 the deadline for the EPA to issue final regulations under Section 316(b) of the federal Clean Water Act requiring 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. Given the recent federal government shutdown, the EPA and Riverkeeper are currently negotiating an extension to the November 4 deadline.

As part of the implementation process for the California Water Resources Control Board's once-through cooling policy, the California Water Board's nuclear review committee is overseeing development of an alternative technology assessment for Diablo Canyon. The deadline for the committee's consultant to submit the final report to the California Water Board has been extended from October 2013 to December 2013. The EPA's final regulations and final implementation of California's once-through cooling policy 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 2012 Annual Report.

Litigation Related to the San Bruno Accident and Natural Gas Spending

Various lawsuits have been filed in San Mateo County Superior Court against PG&E Corporation and the Utility in connection with the San Bruno accident, including two class action lawsuits. The lawsuits seek compensation for personal injury and property damage, and other relief, including punitive damages.In September 2013, the Utility agreed to settle the claims of substantially all of the remaining plaintiffs who sought compensation for personal injury and property damage, and other relief, including punitive damages, following the San Bruno accident.

At September 30, 2013, there were also four purported shareholder derivative lawsuits outstanding against PG&E Corporation and the Utility seeking recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims. Three of these lawsuits are pending in the San Mateo County Superior Court. Although the proceedings have been stayed until further order of the court pending the resolution of the remaining third-party claims, the judge has lifted the stay for the limited purpose of permitting the derivative plaintiffs to obtain the information necessary for them to prepare, file, and serve a consolidated, or master, complaint. A case management conference is scheduled for January 21, 2014. The remaining purported shareholder derivative lawsuit, filed in the U.S. District Court for the Northern District of California, remains stayed pending the resolution of the lawsuits pending in the state Superior Court. PG&E Corporation and the Utility are uncertain when and how these derivative lawsuits will be resolved.

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

For additional information, see "Part I, Item 3. Legal Proceedings" in the 2012 Annual Report and the discussion entitled "Natural Gas 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.

Pending CPUC Investigations

There are three CPUC investigative enforcement proceedings pending against the Utility related to the Utility's natural gas operations and the San Bruno accident. Evidentiary hearings and briefing on the issue of alleged violations have been completed in each of these investigations. The CPUC has stated that it is prepared to impose significant penalties on the Utility if the CPUC determines that the Utility violated applicable laws, rules, and orders. The SED has recommended that the CPUC impose what the SED characterizes as a penalty of $2.25 billion on the Utility, consisting of a $300 million fine payable to the State General Fund and $1.950 billion of non-recoverable costs to perform work under the Utility's pipeline safety enhancement plan and to implement the operational remedies. Several other parties have also submitted penalty recommendations.

For additional information, see "Part I, Item 3. Legal Proceedings" in the 2012 Annual Report and the discussion entitled "Natural Gas Matters – Pending CPUC Investigations" 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.

Other CPUC Enforcement Matters

California gas corporations are required to provide notice to the SED of any self-identified or self-corrected violations of certain state and federal regulations related to the safety of natural gas facilities and the corporations' natural gas operating practices. The SED is authorized to issue citations and impose fines for violations of certain state and federal regulations. In September 2013, the SED published a document explaining the internal procedures the SED staff intends to follow in assessing gas safety violations and determining appropriate enforcement action. In October 2013, the SED issued a citation related to one of the Utility's self-reports and imposed a fine of $140,000. The Utility has filed 58 self-reports with the SED, plus additional follow-up reports, that the SED has not yet addressed. The SED could issue additional citations and impose fines associated with these self-reports.

On August 19, 2013, the CPUC issued two OSCs related to a document submitted by the Utility on July 3, 2013 as "errata" to correct information about some segments in Lines 101 and 147 (two of the Utility's natural gas transmission pipelines that serve the San Francisco peninsula) that had been previously provided to the CPUC in October 2011 to allow the Utility to restore operating pressure on these pipelines. The CPUC could impose penalties on the Utility or take other enforcement action in connection with the OSCs.

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

For additional information, see "Part I, Item 3. Legal Proceedings" in the 2012 Annual Report and the discussion entitled "Natural Gas Matters – Other CPUC 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

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

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 2012 Annual Report entitled "Risk Factors," as supplemented below, and the section of this quarterly report entitled "Cautionary Language Regarding Forward-Looking Statements."

The ultimate outcome of the pending investigations related to the Utility's natural gas operations and the San Bruno accident may require the Utility to incur additional material charges for non-recoverable costs associated with its natural gas operations as well as for civil or criminal fines and penalties. Such charges could negatively affect the availability, amount, and timing of future debt and equity issuances.

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 SED has recommended that the CPUC impose what the SED characterizes as a penalty of $2.25 billion on the Utility, allocated as follows (1) $300 million as a fine to the State General Fund, (2) $435 million for a portion of PSEP costs that were previously disallowed by the CPUC and funded by shareholders, and (3) $1.515 billion to perform PSEP work that was previously approved by the CPUC, implement operational remedies, and for future PSEP costs. If the SED's penalty recommendation is adopted by the CPUC, the Utility estimates that its total unrecovered costs and fines related to natural gas transmission operations would be in excess of $4 billion. Other parties also have submitted penalty recommendations, including the payment of a fine to the State General Fund of differing amounts.

If the final decision requires the Utility to pay penalties or fines to the State General Fund that are materially higher than the $200 million accrued at September 30, 2013, disallows additional PSEP-related costs that were previously authorized for recovery, or prohibits the Utility from recovering other future pipeline expenses, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows will be materially affected. Future developments in the 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" under the heading "Natural Gas Matters" in Item 2: Management's Discussion and Analysis of Financial Condition and Results of Operations.)

The Utility's financing needs would increase if the Utility were required to incur unrecoverable costs and pay fines as a result of the outcome of the investigations. Such financing may become more difficult to obtain, especially if the outcome affected the Utility's credit ratings. In addition, the equity component of the Utility's authorized capital structure could decrease materially as the Utility incurs charges to reflect fines and unrecovered costs the Utility may be required to bear. PG&E Corporation primarily has relied on the public sale of its common stock to raise the funds it contributes to meet the Utility's equity needs. The market price of PG&E Corporation common stock could decline materially depending on the outcome of the investigations and the amount and timing of future share issuances. Declines in the stock price could increase the dilutive effect of future stock issuances and make it more difficult or expensive for PG&E Corporation to complete future equity offerings.

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

During the quarter ended September 30, 2013, PG&E Corporation made equity contributions totaling $170 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, 2013.

Issuer Purchases of Equity Securities

During the quarter ended September 30, 2013, PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. During the quarter ended September 30, 2013, 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, 2013 was 2.34. The Utility’s earnings to combined fixed charges and preferred stock dividends ratio for the nine months ended September 30, 2013 was 2.30. 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 No. 333-172394.

PG&E Corporation’s earnings to fixed charges ratio for the nine months ended September 30, 2013 was 2.26. 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.

ITEM 6. EXHIBITS

*10.1	PG&E Corporation 2005 Supplemental Retirement Savings Plan, as amended effective September 17, 2013
*10.2	PG&E Corporation Defined Contribution Executive Supplemental Retirement Plan, as amended effective September 17, 2013
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
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101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

*Management contract or compensatory agreement.

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

SIGNATURES

Pursuant to the requirements of 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 30, 2013

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