

PG&E CORP

FORM 10-Q (Quarterly Report)

Filed 08/05/09 for the Period Ending 06/30/09

Address	77 BEALE STREET P.O. BOX 770000 SAN FRANCISCO, CA 94177
Telephone	4152677000
CIK	0001004980
Symbol	PCG
SIC Code	4931 - Electric and Other Services Combined
Industry	Electric Utilities
Sector	Utilities
Fiscal Year	12/31

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

(Mark One)

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

For the quarterly period ended June 30, 2009

OR

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

For the transition period from _____ to _____

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

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

PG&E Corporation
One Market, Spear Tower
Suite 2400
San Francisco, California 94105

Address of principal executive offices, including zip code

Pacific Gas and Electric Company
(415) 973-7000

PG&E Corporation
(415) 267-7000

Registrant's telephone number, including area code

Indicate by check mark whether each registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. ☒ 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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ☒ 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:	☒ Large accelerated filer	☐ Accelerated Filer
	☐ Non-accelerated filer	☐ Smaller reporting company
Pacific Gas and Electric Company:	☐ Large accelerated filer	☐ Accelerated Filer
	☒ 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 ☒ No

Pacific Gas and Electric Company: ☐ Yes ☒ 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 July 31, 2009:

PG&E Corporation	370,687,258
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 JUNE 30, 2009
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PART I. FINANCIAL INFORMATION
ITEM 1: CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

PG&E CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(in millions, except per share amounts)	(Unaudited)			
	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2009	2008	2009	2008
Operating Revenues				
Electric	\$ 2,554	\$ 2,645	\$ 4,980	\$ 5,159
Natural gas	640	933	1,645	2,152
Total operating revenues	3,194	3,578	6,625	7,311
Operating Expenses				
Cost of electricity	883	1,097	1,766	2,124
Cost of natural gas	188	487	745	1,262
Operating and maintenance	1,038	991	2,097	2,027
Depreciation, amortization, and decommissioning	429	419	848	821
Total operating expenses	2,538	2,994	5,456	6,234
Operating Income	656	584	1,169	1,077
Interest income	17	33	26	59
Interest expense	(178)	(185)	(359)	(372)
Other income, net	22	5	40	10
Income Before Income Taxes	517	437	876	774
Income tax provision	125	140	240	250
Net Income	392	297	636	524
Preferred stock dividend requirement of subsidiary	4	4	7	7
Income Available for Common Shareholders	\$ 388	\$ 293	\$ 629	\$ 517
Weighted Average Common Shares Outstanding, Basic	368	356	366	355
Weighted Average Common Shares Outstanding, Diluted	369	357	367	356
Net Earnings Per Common Share, Basic	\$ 1.03	\$ 0.80	\$ 1.68	\$ 1.42
Net Earnings Per Common Share, Diluted	\$ 1.02	\$ 0.80	\$ 1.67	\$ 1.42
Dividends Declared Per Common Share	\$ 0.42	\$ 0.39	\$ 0.84	\$ 0.78

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions)	(Unaudited)	
	Balance At	
	June 30, 2009	December 31, 2008
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 338	\$ 219
Restricted cash	1,285	1,290
Accounts receivable:		
Customers (net of allowance for doubtful accounts of \$77 million in 2009 and \$76 million in 2008)	1,481	1,751
Accrued unbilled revenue	757	685
Regulatory balancing accounts	1,304	1,197
Inventories:		
Gas stored underground and fuel oil	107	232
Materials and supplies	204	191
Income taxes receivable	171	120
Prepaid expenses and other	781	718
Total current assets	6,428	6,403
Property, Plant, and Equipment		
Electric	29,580	27,638
Gas	10,387	10,155
Construction work in progress	1,523	2,023
Other	13	17
Total property, plant, and equipment	41,503	39,833
Accumulated depreciation	(13,904)	(13,572)
Net property, plant, and equipment	27,599	26,261
Other Noncurrent Assets		
Regulatory assets	5,969	5,996
Nuclear decommissioning funds	1,740	1,718
Other	461	482
Total other noncurrent assets	8,170	8,196
TOTAL ASSETS	\$ 42,197	\$ 40,860

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)	(Unaudited)	
	Balance At	
	June 30, 2009	December 31, 2008
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term borrowings	\$ 743	\$ 287
Long-term debt, classified as current	252	600
Energy recovery bonds, classified as current	378	370
Accounts payable:		
Trade creditors	863	1,096
Disputed claims and customer refunds	1,552	1,580
Regulatory balancing accounts	611	730
Other	367	343
Interest payable	842	802
Deferred income taxes	424	251
Other	1,400	1,567
Total current liabilities	7,432	7,626
Noncurrent Liabilities		
Long-term debt	9,933	9,321
Energy recovery bonds	1,031	1,213
Regulatory liabilities	3,838	3,657
Pension and other postretirement benefits	2,177	2,088
Asset retirement obligations	1,539	1,684
Income taxes payable	9	35
Deferred income taxes	3,816	3,397
Deferred tax credits	91	94
Other	2,133	2,116
Total noncurrent liabilities	24,567	23,605
Commitments and Contingencies		
Equity		
Shareholders' Equity		
Preferred stock, no par value, authorized 80,000,000 shares, \$100 par value, authorized 5,000,000 shares, none issued	-	-
Common stock, no par value, authorized 800,000,000 shares, issued 368,841,539 common and 673,491 restricted shares in 2009 and issued 361,059,116 common and 1,287,569 restricted shares in 2008	6,219	5,984
Reinvested earnings	3,934	3,614
Accumulated other comprehensive loss	(207)	(221)
Total shareholders' equity	9,946	9,377
Noncontrolling Interest – Preferred Stock of Subsidiary	252	252
Total equity	10,198	9,629
TOTAL LIABILITIES AND EQUITY	\$ 42,197	\$ 40,860

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)	(Unaudited)	
	Six Months Ended	
	June 30,	
	2009	2008
Cash Flows from Operating Activities		
Net income	\$ 636	\$ 524
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	944	902
Allowance for equity funds used during construction	(47)	(32)
Deferred income taxes and tax credits, net	377	346
Other changes in noncurrent assets and liabilities	(46)	493
Effect of changes in operating assets and liabilities:		
Accounts receivable	198	(68)
Inventories	113	(57)
Accounts payable	(143)	121
Income taxes receivable/payable	161	21
Regulatory balancing accounts, net	(228)	(351)
Other current assets	10	431
Other current liabilities	(224)	(79)
Other	3	(3)
Net cash provided by operating activities	1,754	2,248
Cash Flows from Investing Activities		
Capital expenditures	(2,077)	(1,712)
Proceeds from sale of assets	5	12
Decrease (increase) in restricted cash	15	(7)
Proceeds from nuclear decommissioning trust sales	954	636
Purchases of nuclear decommissioning trust investments	(985)	(665)
Other	7	-
Net cash used in investing activities	(2,081)	(1,736)
Cash Flows from Financing Activities		
Net repayments under revolving credit facility	-	(250)
Net repayments of commercial paper, net of discount of \$3 million in 2009 and \$2 million in 2008	(47)	(114)
Proceeds from issuance of short-term debt, net of issuance costs of \$1 million in 2009	499	-
Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of \$16 million in 2009 and \$2 million in 2008	884	598
Long-term debt matured or repurchased	(600)	(454)
Energy recovery bonds matured	(174)	(165)
Common stock issued	182	82
Common stock dividends paid	(286)	(267)
Other	(12)	10
Net cash provided by (used in) financing activities	446	(560)
Net change in cash and cash equivalents	119	(48)
Cash and cash equivalents at January 1	219	345
Cash and cash equivalents at June 30	\$ 338	\$ 297

Supplemental disclosures of cash flow information

Cash received (paid) for:				
Interest, net of amounts capitalized	\$	(298)	\$	(260)
Income taxes, net		201		60
Supplemental disclosures of noncash investing and financing activities				
Common stock dividends declared but not yet paid	\$	155	\$	140
Capital expenditures financed through accounts payable		245		180
Noncash common stock issuances		39		6

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(in millions)	(Unaudited)			
	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2009	2008	2009	2008
Operating Revenues				
Electric	\$ 2,554	\$ 2,645	\$ 4,980	\$ 5,159
Natural gas	640	933	1,645	2,152
Total operating revenues	3,194	3,578	6,625	7,311
Operating Expenses				
Cost of electricity	883	1,097	1,766	2,124
Cost of natural gas	188	487	745	1,262
Operating and maintenance	1,037	991	2,096	2,027
Depreciation, amortization, and decommissioning	429	418	848	820
Total operating expenses	2,537	2,993	5,455	6,233
Operating Income	657	585	1,170	1,078
Interest income	17	33	26	57
Interest expense	(166)	(178)	(339)	(358)
Other income, net	15	7	36	26
Income Before Income Taxes	523	447	893	803
Income tax provision	132	134	263	254
Net Income	391	313	630	549
Preferred stock dividend requirement	4	4	7	7
Income Available for Common Stock	\$ 387	\$ 309	\$ 623	\$ 542

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions)	(Unaudited)	
	Balance At	
	June 30, 2009	December 31, 2008
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 158	\$ 52
Restricted cash	1,285	1,290
Accounts receivable:		
Customers (net of allowance for doubtful accounts of \$77 million in 2009 and \$76 million in 2008)	1,481	1,751
Accrued unbilled revenue	757	685
Related parties	1	2
Regulatory balancing accounts	1,304	1,197
Inventories:		
Gas stored underground and fuel oil	107	232
Materials and supplies	204	191
Income taxes receivable	120	25
Prepaid expenses and other	775	705
Total current assets	6,192	6,130
Property, Plant, and Equipment		
Electric	29,580	27,638
Gas	10,387	10,155
Construction work in progress	1,523	2,023
Total property, plant, and equipment	41,490	39,816
Accumulated depreciation	(13,893)	(13,557)
Net property, plant, and equipment	27,597	26,259
Other Noncurrent Assets		
Regulatory assets	5,969	5,996
Nuclear decommissioning funds	1,740	1,718
Related parties receivable	26	27
Income taxes receivable	18	-
Other	382	407
Total other noncurrent assets	8,135	8,148
TOTAL ASSETS	\$ 41,924	\$ 40,537

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited)	
	Balance At	
	June 30, 2009	December 31, 2008
(in millions, except share amounts)		
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	\$ 743	\$ 287
Long-term debt, classified as current	-	600
Energy recovery bonds, classified as current	378	370
Accounts payable:		
Trade creditors	863	1,096
Disputed claims and customer refunds	1,552	1,580
Related parties	11	25
Regulatory balancing accounts	611	730
Other	366	325
Interest payable	836	802
Income tax payable	-	53
Deferred income taxes	430	257
Other	1,201	1,371
Total current liabilities	6,991	7,496
Noncurrent Liabilities		
Long-term debt	9,585	9,041
Energy recovery bonds	1,031	1,213
Regulatory liabilities	3,838	3,657
Pension and other postretirement benefits	2,127	2,040
Asset retirement obligations	1,539	1,684
Income taxes payable	3	12
Deferred income taxes	3,859	3,449
Deferred tax credits	91	94
Other	2,093	2,064
Total noncurrent liabilities	24,166	23,254
Commitments and Contingencies		
Shareholders' Equity		
Preferred stock without mandatory redemption provisions:		
Nonredeemable, 5.00% to 6.00%, outstanding 5,784,825 shares	145	145
Redeemable, 4.36% to 5.00%, outstanding 4,534,958 shares	113	113
Common stock, \$5 par value, authorized 800,000,000 shares, issued 264,374,809 shares in 2009 and 2008	1,322	1,322
Additional paid-in capital	2,986	2,331
Reinvested earnings	6,403	6,092
Accumulated other comprehensive loss	(202)	(216)
Total shareholders' equity	10,767	9,787
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	\$ 41,924	\$ 40,537

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)	(Unaudited)	
	Six Months Ended	
	June 30,	
	2009	2008
Cash Flows from Operating Activities		
Net income	\$ 630	\$ 549
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	932	902
Allowance for equity funds used during construction	(47)	(32)
Deferred income taxes and tax credits, net	368	316
Other changes in noncurrent assets and liabilities	(34)	480
Effect of changes in operating assets and liabilities:		
Accounts receivable	199	(66)
Inventories	113	(57)
Accounts payable	(140)	123
Income taxes receivable/payable	64	57
Regulatory balancing accounts, net	(228)	(351)
Other current assets	10	429
Other current liabilities	(220)	(73)
Other	3	(3)
Net cash provided by operating activities	1,650	2,274
Cash Flows from Investing Activities		
Capital expenditures	(2,077)	(1,712)
Proceeds from sale of assets	5	12
Decrease (increase) in restricted cash	15	(7)
Proceeds from nuclear decommissioning trust sales	954	636
Purchases of nuclear decommissioning trust investments	(985)	(665)
Net cash used in investing activities	(2,088)	(1,736)
Cash Flows from Financing Activities		
Net repayments under revolving credit facility	-	(250)
Net repayments of commercial paper, net of discount of \$3 million in 2009 and \$2 million in 2008	(47)	(114)
Proceeds from issuance of short-term debt, net of issuance costs of \$1 million in 2009	499	-
Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of \$12 million in 2009 and \$2 million in 2008	538	598
Long-term debt matured or repurchased	(600)	(454)
Energy recovery bonds matured	(174)	(165)
Preferred stock dividends paid	(7)	(7)
Common stock dividends paid	(312)	(284)
Equity contribution	653	50
Other	(6)	16
Net cash provided by (used in) financing activities	544	(610)
Net change in cash and cash equivalents	106	(72)
Cash and cash equivalents at January 1	52	141
Cash and cash equivalents at June 30	\$ 158	\$ 69

Supplemental disclosures of cash flow information

Cash received (paid) for:			
Interest, net of amounts capitalized	\$	(286)	\$ (246)
Income taxes, net		70	60
Supplemental disclosures of noncash investing and financing activities			
Capital expenditures financed through accounts payable	\$	245	\$ 180

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 whose primary purpose is to hold interests in energy-based businesses. PG&E Corporation conducts its business principally through Pacific Gas and Electric Company (“Utility”), a public utility operating in northern and central California. The Utility engages in the businesses of electricity and natural gas distribution; electricity generation, procurement, and transmission; and natural gas procurement, transportation, and storage. The Utility is regulated primarily by the California Public Utilities Commission (“CPUC”) and the Federal Energy Regulatory Commission (“FERC”).

This quarterly report on Form 10-Q is a combined report of PG&E Corporation and the Utility. Therefore, 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, as well as the accounts of variable interest entities for which the Utility absorbs a majority of the risk of loss or gain. All intercompany transactions have been eliminated from the Condensed Consolidated Financial Statements.

The accompanying Condensed Consolidated Financial Statements have been prepared in accordance with generally accepted accounting principles in the United States of America (“GAAP”) for interim financial information and in accordance with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X promulgated by the Securities and Exchange Commission (“SEC”) and therefore do not contain all of the information and footnotes required by GAAP and the SEC for annual financial statements. PG&E Corporation’s and the Utility’s Condensed Consolidated Financial Statements reflect all adjustments that management believes are necessary for the fair presentation of their financial condition and results of operations for the periods presented. The information at December 31, 2008 in both PG&E Corporation’s and the Utility’s Condensed Consolidated Balance Sheets included in this quarterly report was derived from the audited Consolidated Balance Sheets incorporated by reference into their combined Annual Report on Form 10-K for the year ended December 31, 2008. PG&E Corporation’s and the Utility’s combined Annual Report on Form 10-K for the year ended December 31, 2008, together with the information incorporated by reference into such report, is referred to in this quarterly report on Form 10-Q as the “2008 Annual Report.”

The accounting policies used by PG&E Corporation and the Utility are discussed in Notes 1 and 2 of the Notes to the Consolidated Financial Statements in the 2008 Annual Report. Any significant changes to those policies or new significant policies are described in Note 2 below.

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, discussed further below in these notes, relate to the Utility’s regulatory assets and liabilities, environmental remediation liability, asset retirement obligations (“ARO”), income tax-related assets and liabilities, pension plan and other postretirement plan obligations, and accruals for legal matters. Management believes that its estimates and assumptions reflected in the Condensed Consolidated Financial Statements are appropriate and reasonable. A change in management’s estimates or assumptions could result in an adjustment that would have a material impact on PG&E Corporation’s and the Utility’s financial condition and results of operations during the period in which such change occurred.

This quarterly report should be read in conjunction with PG&E Corporation’s and the Utility’s audited Consolidated Financial Statements and Notes to the Consolidated Financial Statements in the 2008 Annual Report.

NOTE 2: NEW AND SIGNIFICANT ACCOUNTING POLICIES

Significant Accounting Policies

Consolidation of Variable Interest Entities

PG&E Corporation and the Utility are required to consolidate any entity in which it has control. In most cases, control can be determined based on majority ownership in accordance with the provisions of Accounting Research Bulletin No. 51, “Consolidated Financial Statements” (“ARB 51”), as interpreted by other standards. However, for certain entities control is difficult to discern based on voting equity interests only. These entities are referred to as variable interest entities (“VIEs”) based on Financial Accounting Standards Board (“FASB”) Interpretation No. (“FIN”) 46 (revised December 2003), “Consolidation of Variable Interest Entities.” Characteristics of a VIE include equity investment at risk that is not sufficient to permit the entity to finance its activities without additional subordinated financial support from other parties or equity investors that lack any of the characteristics of a controlling financial interest. The primary beneficiary, defined as the entity that absorbs a majority of the expected losses of the VIE, receives a majority of the expected residual returns of the VIE, or both, is required to consolidate the VIE.

The Utility’s exposure to VIEs relates to entities with which it has a power purchase agreement. For those entities, the Utility commonly assesses operational risk, commodity price risk, credit risk, and tax benefit risk on a qualitative basis to determine whether the Utility is a primary beneficiary of the entity and required to consolidate the entity. This qualitative assessment also typically involves comparing the contract life to the economic life of the plant to consider the significance of the commodity price risk that the Utility might absorb. As of June 30, 2009, the Utility is not the primary beneficiary of any entities with which it has power purchase agreements.

Although the Utility is not required to consolidate any of these VIEs as of June 30, 2009, it held a significant variable interest in three

VIEs as a result of the following power purchase agreements:

- a 25-year power purchase agreement approved by the CPUC in 2009 to purchase energy from a 250-megawatt (“MW”) solar photovoltaic energy facility beginning upon the date of commercial operations (expected in 2012);
- a 20-year power purchase agreement approved by the CPUC in 2009 to purchase energy from a 550-MW solar photovoltaic energy facility beginning upon the date of commercial operations (expected in 2013); and
- a 25-year power purchase agreement approved by the CPUC in 2008 to purchase energy from a 554-MW solar trough facility beginning upon the date of commercial operations (expected in 2011).

Each of the VIEs is a subsidiary of another company whose activities are financed primarily through equity from investors and proceeds from non-recourse project-specific debt financing. Activities of the VIEs consist of renewable energy production from electric generating facilities for sale to the Utility. Under each of the power purchase agreements, the Utility is obligated to purchase as-delivered electric generation output from the VIEs. The Utility does not provide any other financial or other support to these VIEs. The Utility’s financial exposure is limited to the amounts paid for delivered electricity.

Asset Retirement Obligations

PG&E Corporation and the Utility account for ARO in accordance with Statement of Financial Accounting Standards (“SFAS”) No. 143, “Accounting for Asset Retirement Obligations” (“SFAS No. 143”) and FIN 47, “Accounting for Conditional Asset Retirement Obligations - an Interpretation of FASB Statement No. 143.” SFAS No. 143 requires that an asset retirement obligation be recorded at fair value in the period in which it is incurred if a reasonable estimate of fair value can be made. In the same period, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset.

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

(in millions)	
ARO liability at December 31, 2008	\$ 1,684
Revision in estimated cash flows	(172)
Accretion	49
Liabilities settled	(22)
ARO liability at June 30, 2009	<u>\$ 1,539</u>

Detailed studies of the cost to decommission the Utility’s nuclear power plants are conducted every three years in conjunction with the filing of the Nuclear Decommissioning Cost Triennial Proceedings. Estimated cash flows were revised as a result of the studies completed in the first quarter of 2009.

Share-Based Compensation

The following tables provide a summary of total compensation expense for PG&E Corporation and the Utility for share-based compensation awards for the three and six months ended June 30, 2009 and 2008:

(in millions)	PG&E Corporation		Utility	
	Three Months Ended		Three Months Ended	
	June 30,		June 30,	
	2009	2008	2009	2008
Stock options	\$ -	\$ -	\$ -	\$ -
Restricted stock	3	5	2	3
Restricted stock units ⁽¹⁾	1	-	1	-
Performance shares	6	12	5	8
Total compensation expense (pre-tax)	\$ 10	\$ 17	\$ 8	\$ 11
Total compensation expense (after-tax)	\$ 6	\$ 10	\$ 5	\$ 7

⁽¹⁾ Beginning January 1, 2009, PG&E Corporation awarded restricted stock units (“RSUs”) instead of restricted stock as permitted by the PG&E Corporation 2006 Long-Term Incentive Plan. RSUs are hypothetical shares of stock that will generally vest in 20% increments on the first business day of March in 2010, 2011, and 2012, with the remaining 40% vesting on the first business day of March 2013. Each vested RSU is settled for one share of PG&E Corporation common stock. Additionally, upon settlement, RSUs recipients receive payment for the amount of dividend equivalents associated with the vested RSUs that have accrued since the date of grant.

(in millions)	PG&E Corporation		Utility	
	Six Months Ended		Six Months Ended	
	June 30,		June 30,	
	2009	2008	2009	2008
Stock options	\$ -	\$ 1	\$ -	\$ 1
Restricted stock	5	14	4	9
Restricted stock units ⁽¹⁾	7	-	4	-
Performance shares	22	8	15	4
Total compensation expense (pre-tax)	\$ 34	\$ 23	\$ 23	\$ 14
Total compensation expense (after-tax)	\$ 20	\$ 14	\$ 14	\$ 8

⁽¹⁾ Beginning January 1, 2009, PG&E Corporation awarded RSUs instead of restricted stock as permitted by the PG&E Corporation 2006 Long-Term Incentive Plan. RSUs are hypothetical shares of stock that will generally vest in 20% increments on the first business day of March in 2010, 2011, and 2012, with the remaining 40% vesting on the first business day of March 2013. Each vested RSU is settled for one share of PG&E Corporation common stock. Additionally, upon settlement, RSUs recipients receive payment for the amount of dividend equivalents associated with the vested RSUs that have accrued since the date of grant.

Pension and Other Postretirement Benefits

PG&E Corporation and the Utility provide a non-contributory defined benefit pension plan for certain employees and retirees (referred to collectively as “pension benefits”), contributory postretirement medical plans for certain employees and retirees and their eligible dependents, and non-contributory postretirement life insurance plans for certain employees and retirees (referred to collectively as “other benefits”). PG&E Corporation and the Utility use a December 31 measurement date for all plans.

The net periodic benefit costs as reflected in PG&E Corporation’s Condensed Consolidated Statements of Income as a component of Operating and maintenance for the three and six months ended June 30, 2009 and 2008 are as follows:

(in millions)	Pension Benefits		Other Benefits	
	Three Months Ended		Three Months Ended	
	June 30,		June 30,	
	2009	2008	2009	2008
Service cost for benefits earned	\$ 67	\$ 59	\$ 7	\$ 7
Interest cost	155	144	21	20
Expected return on plan assets	(145)	(175)	(17)	(24)
Amortization of transition obligation	-	-	7	7
Amortization of prior service cost	12	12	4	4
Amortization of unrecognized (gain) loss	24	-	1	(4)
Net periodic benefit cost	113	40	23	10
Less: transfer to regulatory account ⁽¹⁾	(72)	1	-	-
Total	\$ 41	\$ 41	\$ 23	\$ 10

⁽¹⁾ For the three months ended June 30, 2009 and 2008, the Utility recorded \$72 million as an addition to the existing pension regulatory asset and \$1 million as an addition to the existing pension regulatory liability, respectively, to reflect the difference between pension expense or income for accounting purposes and pension expense or income for ratemaking purposes, which is based on a funding approach.

(in millions)	Pension Benefits		Other Benefits	
	Six Months Ended		Six Months Ended	
	June 30,		June 30,	
	2009	2008	2009	2008
Service cost for benefits earned	\$ 133	\$ 118	\$ 15	\$ 15
Interest cost	310	287	42	40
Expected return on plan assets	(290)	(349)	(34)	(47)
Amortization of transition obligation	-	-	13	12
Amortization of prior service cost	23	24	8	8
Amortization of unrecognized (gain) loss	49	-	2	(8)
Net periodic benefit cost	225	80	46	20
Less: transfer to regulatory account ⁽¹⁾	(143)	2	-	-
Total	\$ 82	\$ 82	\$ 46	\$ 20

⁽¹⁾ For the six months ended June 30, 2009 and 2008, the Utility recorded \$143 million as an addition to the existing pension regulatory asset and \$2 million as an addition to the existing pension regulatory liability, respectively, to reflect the difference between pension expense or income for accounting purposes and pension expense or income for ratemaking purposes, which is based on a funding approach.

There was no material difference between PG&E Corporation’s and the Utility’s consolidated net periodic benefit costs for the three and six months ended June 30, 2009 and 2008.

Adoption of New Accounting Pronouncements

Disclosures about Derivative Instruments and Hedging Activities - an amendment of FASB Statement No. 133

On January 1, 2009, PG&E Corporation and the Utility adopted SFAS No. 161, “Disclosures about Derivative Instruments and Hedging Activities - an amendment of FASB Statement No. 133” (“SFAS No. 161”). SFAS No. 161 amends and expands the disclosure requirements of SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities” (“SFAS No. 133”). SFAS No. 161 requires an entity to provide qualitative disclosures about its objectives and strategies for using derivative instruments and quantitative disclosures that detail the fair value amounts of, and gains and losses on, derivative instruments. SFAS No. 161 also requires disclosures about credit risk-related contingent features of derivative instruments. (See Note 7 of the Notes to the Condensed Consolidated Financial Statements.)

Noncontrolling Interests in Consolidated Financial Statements - an amendment of ARB No. 51

On January 1, 2009, PG&E Corporation and the Utility adopted SFAS No. 160, “Noncontrolling Interests in Consolidated Financial Statements - an amendment of ARB No. 51” (“SFAS No. 160”). SFAS No. 160 amends ARB 51 to establish accounting and reporting standards for a noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS No. 160 defines a “noncontrolling interest,” previously called a “minority interest,” as the portion of equity in a subsidiary not attributable, directly or indirectly, to a parent. Among other items, this standard requires that an entity include a noncontrolling interest in its consolidated statement of financial position within equity separate from the parent’s equity, report amounts inclusive of both the parent’s and noncontrolling interest’s shares in consolidated net income, and separately report the amounts of consolidated net income attributable to the parent and noncontrolling interest on the consolidated statement of operations. If a subsidiary is deconsolidated, any retained noncontrolling equity investment in the former subsidiary must be measured at fair value, and a gain or loss must be recognized in net income based on such fair value.

PG&E Corporation has reclassified its noncontrolling interest in the Utility from Preferred Stock of Subsidiaries to equity in PG&E Corporation’s Condensed Consolidated Financial Statements in accordance with SFAS No. 160 for all periods presented. The Utility had no material noncontrolling interests in consolidated subsidiaries as of June 30, 2009 and December 31, 2008.

The presentation and disclosure requirements of SFAS No. 160 were applied retrospectively. Other than the change in presentation of noncontrolling interests, adoption of SFAS No. 160 did not have a material impact on PG&E Corporation’s or the Utility’s Condensed Consolidated Financial Statements.

Issuer’s Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement

On January 1, 2009, PG&E Corporation and the Utility adopted Emerging Issues Task Force (“EITF”) 08-5, “Issuer’s Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement” (“EITF 08-5”). EITF 08-5 clarifies the unit of account in determining the fair value of a liability under SFAS No. 107, “Disclosures about Fair Value of Financial Instruments” (“SFAS No. 107”), or SFAS No. 133. Specifically, it requires an entity to exclude any third-party credit enhancements that are issued with, and are inseparable from, a debt instrument from the fair value measurement of that debt instrument. Adoption of EITF 08-5 did not have a material impact on PG&E Corporation’s or the Utility’s Condensed Consolidated Financial Statements.

Equity Method Investment Accounting

On January 1, 2009, PG&E Corporation and the Utility adopted EITF 08-6, “Equity Method Investment Accounting Considerations” (“EITF 08-6”). EITF 08-6 applies to investments accounted for under the equity method and requires an entity to measure its equity investment initially at cost. Generally, contingent consideration associated with an equity method investment should only be included in the initial measurement of that investment if it is required to be recognized by specific authoritative guidance other than SFAS No. 141 (revised 2007), “Business Combinations.” However, the investor in an equity method investment could be required to recognize a liability for the related contingent consideration features if the fair value of the investor’s share of the investee’s net assets exceeds the investor’s initial costs. An equity method investor is required to recognize other-than-temporary impairments of an equity method investment and shall account for a share issuance by an investee as if the investor had sold a proportionate share of its investment. Any gain or loss to the investor resulting from an investee’s share issuance shall be recognized in earnings. Adoption of EITF 08-6 did not have a material impact on PG&E Corporation’s or the Utility’s Condensed Consolidated Financial Statements.

Subsequent Events

On June 30, 2009, PG&E Corporation and the Utility adopted SFAS No. 165, “Subsequent Events” (“SFAS No. 165”). SFAS No. 165 does not significantly change the prior accounting practice for subsequent events except for the requirement to disclose the date through which an entity has evaluated subsequent events and the basis for that date. PG&E Corporation and the Utility have evaluated material subsequent events through August 5, 2009, the issue date of PG&E Corporation’s and the Utility’s Condensed Consolidated Financial Statements. Other than this disclosure, adoption of SFAS No. 165 did not have a material impact on PG&E Corporation’s or the Utility’s Condensed Consolidated Financial Statements.

Interim Disclosures about Fair Value of Financial Instruments

On June 30, 2009, PG&E Corporation and the Utility adopted FASB Staff Position (“FSP”) SFAS 107-1 and APB 28-1, “Interim Disclosures about Fair Value of Financial Instruments.” This FSP amends SFAS No. 107 and Accounting Principles Board Opinion No. 28, “Interim Financial Reporting,” to require disclosures about the fair value of financial instruments for interim reporting periods that were previously only required for annual reporting periods. An entity is required to disclose the fair value of financial assets and liabilities together with the related carrying amount and where the carrying amount is classified in the Condensed Consolidated Balance Sheets. (See Note 8 of the Notes to the Condensed Consolidated Financial Statements.)

Recognition and Presentation of Other-Than-Temporary Impairments

On June 30, 2009, PG&E Corporation and the Utility adopted FSP SFAS 115-2 and SFAS 124-2, “Recognition and Presentation of Other-Than-Temporary Impairments” (“FSP SFAS 115-2 and SFAS 124-2”). Under this FSP, to assess whether an other-than-temporary impairment exists for a debt security, an entity must (1) evaluate the likelihood of liquidating the debt security prior to recovering its cost basis and (2) determine if any impairment of the debt security is related to credit losses. In addition, this FSP requires enhanced disclosures of other-than-temporary impairments on debt and equity securities in the financial statements. Recognition and measurement guidance for other-than-

temporary impairments of equity securities is not amended by this FSP. Adoption of FSP SFAS 115-2 and SFAS 124-2 did not have a material impact on PG&E Corporation's or the Utility's Condensed Consolidated Financial Statements.

Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly

On June 30, 2009, PG&E Corporation and the Utility adopted FSP SFAS 157-4, “Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly” (“FSP SFAS 157-4”). This FSP amends SFAS No. 157, “Fair Value Measurements” (“SFAS No. 157”), to provide guidance on estimating fair value when the volume or the level of activity for an asset or a liability has significantly decreased or when transactions are not orderly, when compared with normal market conditions. In particular, this FSP calls for adjustments to quoted prices or historical transaction data when estimating fair value in such circumstances. Guidance to identify such circumstances is also provided. Furthermore, this FSP requires fair value measurement disclosures made pursuant to SFAS No. 157 to be categorized by major security type, i.e., based on the nature and risks of the security. (See Note 8 of the Notes to the Condensed Consolidated Financial Statements.) Other than this change, adoption of FSP SFAS 157-4 did not have a material impact on PG&E Corporation’s or the Utility’s Condensed Consolidated Financial Statements.

Accounting Pronouncements Issued But Not Yet Adopted

Employers’ Disclosures about Postretirement Benefit Plan Assets

In December 2008, the FASB issued FSP SFAS 132(R)-1, “Employers’ Disclosures about Postretirement Benefit Plan Assets” (“FSP SFAS 132(R)-1”). FSP SFAS 132(R)-1 amends and expands the disclosure requirements of SFAS No. 132 (revised 2003), “Employers’ Disclosures about Pensions and Other Postretirement Benefits — an amendment of FASB Statements No. 87, 88, and 106.” An entity is required to provide qualitative disclosures about how investment allocation decisions are made, the inputs and valuation techniques used to measure the fair value of plan assets, and the concentration of risk within plan assets. Additionally, quantitative disclosures are required showing the fair value of each major category of plan assets, the levels in which each asset is classified within the fair value hierarchy, and a reconciliation for the period of plan assets that are measured using significant unobservable inputs. FSP SFAS 132(R)-1 is effective prospectively for PG&E Corporation and the Utility for the annual period ending December 31, 2009 and for subsequent annual periods. PG&E Corporation and the Utility will include the expanded disclosures described above in PG&E Corporation’s and the Utility’s Consolidated Financial Statements for such annual periods.

Accounting for Transfers of Financial Assets - an amendment of FASB Statement No. 140

In June 2009, the FASB issued SFAS No. 166, “Accounting for Transfers of Financial Assets - an amendment of FASB Statement No. 140” (“SFAS No. 166”). SFAS No. 166 eliminates the concept of a qualifying special-purpose entity and clarifies the requirements for derecognizing a financial asset and for applying sale accounting to a transfer of a financial asset. In addition, SFAS No. 166 requires an entity to disclose more information about transfers of financial assets, the entity’s continuing involvement, if any, with transferred financial assets, and the entity’s continuing risks, if any, from transferred financial assets. SFAS No. 166 is effective for PG&E Corporation and the Utility beginning on January 1, 2010. PG&E Corporation and the Utility are currently evaluating the impact of SFAS No. 166.

Amendments to FASB Interpretation No. 46(R)

In June 2009, the FASB issued SFAS No. 167, “Amendments to FASB Interpretation No. 46(R)” (“SFAS No. 167”). SFAS No. 167 amends FIN 46 (revised December 2003), “Consolidation of Variable Interest Entities” (“FIN 46R”), regarding when and how to determine, or re-determine, whether an entity is a VIE. In addition, SFAS No. 167 replaces FIN 46R’s quantitative approach for determining who has a controlling financial interest in a VIE with a qualitative approach. Furthermore, SFAS No. 167 requires ongoing assessments of whether an entity is the primary beneficiary of a VIE. SFAS No. 167 is effective prospectively for PG&E Corporation and the Utility beginning on January 1, 2010. PG&E Corporation and the Utility are currently evaluating the impact of SFAS No. 167.

The FASB Accounting Standards CodificationTM and the Hierarchy of Generally Accepted Accounting Principles - a replacement of FASB Statement No. 162

In June 2009, the FASB issued SFAS No. 168, “The FASB Accounting Standards CodificationTM and the Hierarchy of Generally Accepted Accounting Principles - a replacement of FASB Statement No. 162” (“SFAS No. 168”). SFAS No. 168 nullifies SFAS No. 162, “The Hierarchy of Generally Accepted Accounting Principles,” and defines authoritative GAAP for nongovernmental entities to be only comprised of the FASB Accounting Standards CodificationTM (“Codification”) and, for SEC registrants, guidance issued by the SEC. The Codification is a reorganization and compilation of all then-existing authoritative GAAP for nongovernmental entities, except for guidance issued by the SEC. PG&E Corporation and the Utility anticipate that adopting SFAS No. 168 will only change the referencing convention of GAAP in PG&E Corporation’s and the Utility’s Notes to the Condensed Consolidated Financial Statements. SFAS No. 168 is effective prospectively for PG&E Corporation and the Utility beginning on July 1, 2009.

NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

The Utility accounts for the financial effects of regulation in accordance with SFAS No. 71, “Accounting for the Effects of Certain Types of Regulation,” as amended (“SFAS No. 71”), which applies to regulated entities whose rates are designed to recover the cost of providing service. SFAS No. 71 applies to all of the Utility’s operations.

The Utility capitalizes and records, as a regulatory asset, costs that would otherwise be charged to expense if it is probable that the incurred costs will be recovered in future rates. The regulatory assets are amortized over future periods when the costs are expected to be recovered. If costs expected to be incurred in the future are currently being recovered through rates, the Utility records those expected future costs as regulatory liabilities. In addition, amounts that are probable of being credited or refunded to customers in the future are recorded as regulatory liabilities.

To the extent portions of the Utility’s operations cease to be subject to SFAS No. 71, or recovery is no longer probable as a result of changes in regulation or other reasons, the related regulatory assets and liabilities are written off.

Regulatory Assets

Long-Term Regulatory Assets

Long-term regulatory assets are composed of the following:

(in millions)	Balance At	
	June 30, 2009	December 31, 2008
Pension benefits	\$ 1,696	\$ 1,624
Energy recovery bonds	1,322	1,487
Deferred income tax	913	847
Utility retained generation	772	799
Price risk management	410	362
Environmental compliance costs	392	385
Unamortized loss, net of gain, on reacquired debt	213	225
Regulatory assets associated with plan of reorganization	88	99
Contract termination costs	75	82
Other	88	86
Total long-term regulatory assets	\$ 5,969	\$ 5,996

The regulatory asset for pension benefits represents the cumulative differences between amounts recognized in accordance with GAAP and amounts recognized for ratemaking purposes, which also includes amounts that otherwise would be fully recorded to Accumulated other comprehensive loss in the Condensed Consolidated Balance Sheets in accordance with SFAS No. 158 “Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans.”

The regulatory asset for energy recovery bonds (“ERBs”) represents the refinancing of the settlement regulatory asset established under the December 19, 2003 settlement agreement among PG&E Corporation, the Utility, and the CPUC to resolve the Utility’s Chapter 11 of the U.S. Bankruptcy Code (“Chapter 11”) proceeding (“Chapter 11 Settlement Agreement”). The regulatory asset is amortized over the life of the bond, consistent with the period over which the related billed revenues and bond-related expenses are recognized. The Utility expects to fully recover this asset by the end of 2012 when the ERBs mature.

The regulatory assets for deferred income tax represent deferred income tax benefits previously passed through to customers and are offset by deferred income tax liabilities. Tax benefits to customers have been passed through, as the CPUC requires utilities under its jurisdiction to follow the “flow-through” method of passing certain tax benefits to customers. The “flow-through” method ignores the effect of deferred taxes on rates. Based on current regulatory ratemaking and income tax laws, the Utility expects to recover deferred income taxes related to regulatory assets over periods ranging from 1 to 45 years.

In connection with the Chapter 11 Settlement Agreement in 2004, the Utility recognized a one-time noncash gain of \$1.2 billion related to the recovery of the Utility’s retained generation regulatory assets. The Utility amortizes the individual components of these regulatory assets consistent with the period over which the related revenues are recognized over the respective lives of the underlying generation facilities. The weighted average remaining life of the assets is 16 years.

Price risk management regulatory assets represent the deferral of unrealized losses related to price risk management derivative instruments with terms in excess of one year. (See Note 7 of the Notes to the Condensed Consolidated Financial Statements.)

The regulatory assets for environmental compliance costs represent the portion of estimated environmental remediation liabilities that the Utility expects to recover in future rates as actual remediation costs are incurred. The Utility expects to recover these costs over the next 30 years. (See Note 11 of the Notes to the Condensed Consolidated Financial Statements.)

The regulatory assets for unamortized loss, net of gain, on reacquired debt represents costs related to debt reacquired or redeemed prior to maturity with associated discount and debt issuance costs. These costs are expected to be recovered over the remaining original amortization period of the reacquired debt over the next 17 years, and these costs will be fully recovered by 2026.

Regulatory assets associated with the Utility's plan of reorganization include costs incurred in financing the Utility's plan of reorganization under Chapter 11 and costs to oversee the environmental enhancement projects of the Pacific Forest and Watershed Land Stewardship Council, an entity that was established pursuant to the Utility's plan of reorganization. The Utility expects to recover these costs over the remaining periods ranging from 4 to 25 years, and these costs should be fully recovered by 2034.

The regulatory assets for contract termination costs represent amounts that the Utility incurred in terminating a 30-year power purchase agreement. This regulatory asset will be amortized and collected in rates on a straight-line basis through the end of September 2014, the power purchase agreement's original termination date.

At June 30, 2009, "Other" primarily consisted of regulatory assets relating to ARO costs recorded in accordance with GAAP, which are probable of future recovery through the ratemaking process, as well as cost associated with the Steam Generator Replacement Project at the Utility's Diablo Canyon Power Plant, as approved by the CPUC for future recovery. At December 31, 2008, "Other" primarily consisted of regulatory assets relating to ARO costs, as well as scheduling coordinator costs that the Utility incurred beginning in 1998 in its capacity as scheduling coordinator for its then existing wholesale transmission customers.

In general, the Utility does not earn a return on regulatory assets in which the related costs do not accrue interest. Accordingly, the Utility earns a return only on the Utility's retained generation regulatory assets; unamortized loss, net of gain, on reacquired debt; and regulatory assets associated with the plan of reorganization.

Current Regulatory Assets

At June 30, 2009 and December 31, 2008, the Utility had current regulatory assets of \$547 million and \$355 million, respectively, consisting primarily of the current component of price risk management regulatory assets. Price risk management regulatory assets represent the deferral of unrealized losses related to price risk management derivative instruments with terms of less than one year. (See Note 7 of the Notes to the Condensed Consolidated Financial Statements.) Current regulatory assets are included in Prepaid expenses and other in the Condensed Consolidated Balance Sheets.

Regulatory Liabilities

Long-Term Regulatory Liabilities

Long-term regulatory liabilities are composed of the following:

(in millions)	Balance At	
	June 30, 2009	December 31, 2008
Cost of removal obligation	\$ 2,841	\$ 2,735
Public purpose programs	445	442
Recoveries in excess of asset retirement obligation	348	226
Price risk management	82	81
Gateway Generating Station	66	67
Environmental remediation insurance recoveries	38	52
Other	18	54
Total long-term regulatory liabilities	\$ 3,838	\$ 3,657

Cost of removal regulatory liabilities represent revenues collected for asset removal costs that the Utility expects to incur in the future, less actual costs incurred.

Public purpose program regulatory liabilities represent revenues designated for public purpose program costs that are expected to be incurred in the future. Public purpose program regulatory liabilities include the California Solar Initiative program's revenue that was collected from customers to pay for costs that the Utility expects to incur in the future to promote the use of solar energy in residential homes and commercial, industrial, and agricultural properties.

Regulatory liability for recoveries in excess of asset retirement obligation represents differences between amounts collected in rates for decommissioning the Utility's nuclear power facilities and the decommissioning obligation recorded in accordance with GAAP. Decommissioning costs recovered in rates are placed in nuclear decommissioning trusts. Regulatory liability for recoveries in excess of asset retirement obligation also represents the deferral of realized and unrealized gains and losses on those nuclear decommissioning trust assets.

Price risk management regulatory liabilities represent the deferral of unrealized gains related to price risk management derivative instruments with terms in excess of one year. (See Note 7 of the Notes to the Condensed Consolidated Financial Statements.)

The Gateway Generating Station ("Gateway") regulatory liability represents the gain associated with the Utility's acquisition of Gateway, as part of a settlement that the Utility entered with Mirant Corporation, to be credited to customers in future rates. The associated liability is being amortized over 30 years beginning in January 2009 when Gateway was placed in service.

Regulatory liabilities associated with environmental remediation insurance recoveries are refunded to customers as a reduction to rates, as costs are incurred for hazardous substance remediation.

"Other" is an aggregate of regulatory liabilities representing amounts collected for future costs.

Current Regulatory Liabilities

At June 30, 2009 and December 31, 2008, the Utility had current regulatory liabilities of \$278 million and \$313 million, respectively, primarily consisting of regulatory liabilities for the current portion of electric transmission wheeling revenue refunds and amounts that the Utility expects to refund to customers for over-collected electric transmission rates. Current regulatory liabilities are included in Current Liabilities – Other in the Condensed Consolidated Balance Sheets.

Regulatory Balancing Accounts

The Utility uses regulatory balancing accounts to accumulate differences between actual billed and unbilled revenues and the Utility's authorized revenue requirements for the period. The Utility also uses regulatory balancing accounts to accumulate differences between incurred costs and actual billed and unbilled revenues, as well as differences between incurred costs and authorized revenue meant to recover those costs. Under-collections that are probable of recovery through regulated rates are recorded as regulatory balancing account assets. Over-collections that are probable of being credited to customers are recorded as regulatory balancing account liabilities. The CPUC does not allow the Utility to offset regulatory balancing account assets against regulatory balancing account liabilities in the Condensed Consolidated Balance Sheets.

The Utility's current regulatory balancing accounts represent the amount expected to be refunded to or received from the Utility's customers through authorized rate adjustments within the next 12 months. Regulatory balancing accounts that the Utility does not expect to collect or refund in the next 12 months are included in Other Noncurrent Assets – Regulatory assets and Noncurrent Liabilities – Regulatory liabilities in the Condensed Consolidated Balance Sheets.

Current Regulatory Balancing Accounts, net

	Receivable (Payable)	
	Balance At	
	June 30, 2009	December 31, 2008
(in millions)		
Utility generation	\$ 493	\$ 164
Distribution revenue adjustment mechanism	249	40
Modified transition cost	220	214
Transmission revenue	156	173
Energy resource recovery	1	384
DWR power charge collection	(92)	(83)
Public purpose programs	(138)	(263)
Energy recovery bonds	(164)	(231)
Other	(32)	69
Total regulatory balancing accounts, net	\$ 693	\$ 467

The utility generation balancing account is used to record and recover the authorized revenue requirements associated with Utility-owned electric generation, including capital and related non-fuel operating and maintenance expenses. The Utility's recovery of these revenue requirements is independent, or "decoupled," from the volume of sales; therefore, the Utility recognizes revenue evenly over the year even though the level of cash collected from customers will fluctuate depending on the volume of electricity sales. During periods of more temperate weather, there is generally an under-collection in this balancing account due to lower electricity sales and lower rates. During the warmer months of summer, the under-collection generally decreases due to higher rates and electric usage that cause an increase in generation revenues.

The distribution revenue adjustment mechanism balancing account is used to record and recover the authorized electric distribution revenue requirements and certain other electric distribution-related authorized costs. The Utility recognizes revenue evenly over the year even though the level of cash collected from customers will fluctuate depending on the volume of electricity sales. During periods of more temperate weather, there is generally an under-collection in this balancing account due to lower electricity sales and lower rates. During the warmer months of summer, the under-collection generally decreases due to higher rates and electric usage that cause an increase in distribution revenues.

The modified transition cost balancing account is used to track the recovery of ongoing competition transition charges (“CTC”), primarily consisting of above-market costs associated with power purchase contracts that were being collected in CPUC-approved rates on or before December 20, 1995 (including costs incurred by the Utility with CPUC approval to restructure, renegotiate, or terminate the contracts). The recovery of ongoing CTC can continue for the term of the contract. The amount of above-market costs associated with the eligible power purchase contracts is determined each year in the energy resource recovery account (“ERRA”) forecast proceeding by comparing the ongoing CTC-eligible contract costs to a CPUC-approved market benchmark to determine whether there are stranded costs associated with these contracts.

The transmission revenue balancing account represents the difference between electric transmission wheeling revenues received by the Utility from the California Independent System Operator (“CAISO”) (on behalf of electric transmission wholesale customers) and refunds to customers plus interest.

The Utility is generally authorized to recover 100% of its prudently incurred electric fuel and energy procurement costs through the ERRA. The Utility files annual forecasts of energy procurement costs that it expects to incur during the following year, and rates are set to recover such expected costs. The ERRA tracks actual electric costs, as well as fuel and energy procurement costs, excluding the costs incurred under contracts entered into by the California Department of Water Resources (“DWR”) to purchase energy allocated to the Utility’s customers.

The DWR power charge collection balancing account tracks the difference between the amounts collected from customers by the Utility on behalf of the DWR, and the amounts remitted to the DWR for energy delivered to customers on behalf of the Utility.

The public purpose program balancing accounts primarily track the recovery of the authorized public purpose program revenue requirement and the actual cost of such programs. The public purpose programs primarily consist of the energy efficiency programs; low-income energy efficiency programs; research, development, and demonstration programs; and renewable energy programs. A refund of \$230 million from the California Energy Commission for unspent renewable program funding previously collected is being returned to customers through lower rates throughout 2009.

The energy recovery bonds balancing account records certain benefits and costs associated with ERBs that are provided to, or received from, customers. In addition, this account ensures that customers receive the benefits of the net amount of energy supplier refunds, claim offsets, and other credits received by the Utility after the second series of ERBs were issued.

At June 30, 2009, “Other” primarily consisted of the gas purchase and distribution balancing accounts that track actual gas costs and recoveries, as well as the difference between the authorized and recovered gas base revenue requirement. At December 31, 2008, “Other” consisted of the customer energy efficiency (“CEE”) incentive account that records any incentive awards earned by the Utility for implementing CEE programs, as well as a FERC-mandated balancing account for reliability services that ensures the participating transmission owner neither under-recovers nor over-recovers the reliability services costs from customers.

NOTE 4: DEBT

PG&E Corporation

Senior Notes

On March 12, 2009, PG&E Corporation issued \$350 million principal amount of 5.75% Senior Notes due April 1, 2014.

Credit Facility

At June 30, 2009, PG&E Corporation had no borrowings outstanding under its \$187 million revolving credit facility. PG&E Corporation amended its revolving credit facility on April 27, 2009 to remove Lehman Brothers Bank, FSB (“Lehman Bank”) as a lender. Prior to the amendment, the total borrowing capacity under the revolving credit facility was \$200 million, including a commitment from Lehman Bank that represented \$13 million, or 7%, of the total.

Utility

Senior Notes

On March 6, 2009, the Utility issued \$550 million principal amount of 6.25% Senior Notes due March 1, 2039.

On June 11, 2009, the Utility issued \$500 million principal amount of Floating Rate Senior Notes due June 10, 2010. The interest rate for the Floating Rate Senior Notes is equal to the three-month London Interbank Offered Rate plus 0.95% and will reset quarterly beginning on September 10, 2009. At June 30, 2009, the interest rate on the Floating Rate Senior Notes was 1.60%.

Credit Facility and Short-Term Borrowings

At June 30, 2009, the Utility had \$303 million of letters of credit outstanding under the Utility's \$1.94 billion revolving credit facility. The Utility amended its revolving credit facility on April 27, 2009 to remove Lehman Bank as a lender. Prior to the amendment, the total borrowing capacity under the revolving credit facility was \$2.0 billion, including a commitment from Lehman Bank that represented \$60 million, or 3%, of the total.

The revolving credit facility also provides liquidity support for commercial paper offerings. At June 30, 2009, the Utility had \$243 million of commercial paper outstanding at an average yield of 0.68%.

Recovery Bonds

PG&E Energy Recovery Funding LLC ("PERF"), a wholly owned consolidated subsidiary of the Utility, issued two separate series of ERBs in the aggregate amount of \$2.7 billion in 2005. The proceeds of the ERBs were used by PERF to purchase from the Utility the right, known as "recovery property," to be paid a specified amount from a dedicated rate component. The total amount of ERB principal outstanding was \$1.4 billion at June 30, 2009.

While PERF is a wholly owned subsidiary of the Utility, it is legally separate from the Utility. The assets, including the recovery property, of PERF are not available to creditors of the Utility or PG&E Corporation, and the recovery property is not legally an asset of the Utility or PG&E Corporation.

NOTE 5: EQUITY

PG&E Corporation's and the Utility's changes in equity for the six months ended June 30, 2009 were as follows:

(in millions)	PG&E Corporation	Utility
	Total Equity	Total Shareholders' Equity
Balance at December 31, 2008	\$ 9,629	\$ 9,787
Net income	636	630
Common stock issued	221	-
Share-based compensation amortization	12	-
Common stock dividends declared and paid	(154)	(312)
Common stock dividends declared but not yet paid	(155)	-
Preferred stock dividend requirement	-	(7)
Preferred stock dividend requirement of subsidiary	(7)	-
Tax benefit from employee stock plans	2	2
Other comprehensive income	14	14
Equity contribution	-	653
Balance at June 30, 2009	\$ 10,198	\$ 10,767

For the six months ended June 30, 2009, PG&E Corporation contributed equity of \$653 million to the Utility in order to maintain the 52% common equity target authorized by the CPUC and to ensure that the Utility has adequate capital to fund its capital expenditures.

Dividends

During the six months ended June 30, 2009, the Utility paid common stock dividends totaling \$312 million to PG&E Corporation.

During the six months ended June 30, 2009, PG&E Corporation paid common stock dividends totaling \$286 million, net of \$11 million that was reinvested in additional shares of common stock by participants in the PG&E Corporation Dividend Reinvestment and Stock Purchase Plan. On June 17, 2009, the Board of Directors of PG&E Corporation declared a dividend of \$0.42 per share, totaling \$155 million, which was paid on July 15, 2009 to shareholders of record on June 30, 2009.

During the six months ended June 30, 2009, the Utility paid cash dividends totaling \$7 million to holders of its outstanding series of preferred stock. On June 17, 2009, the Board of Directors of the Utility declared a cash dividend totaling \$3 million on its outstanding series of preferred stock, payable on August 15, 2009 to shareholders of record on July 31, 2009.

NOTE 6: EARNINGS PER SHARE

Earnings per common share (“EPS”) is calculated utilizing the “two-class” method, by dividing the sum of distributed earnings to common shareholders and undistributed earnings allocated to common shareholders by the weighted average number of common shares outstanding during the period. In applying the two-class method, undistributed earnings are allocated to both common shares and participating securities. PG&E Corporation’s Convertible Subordinated Notes are entitled to receive pass-through dividends and meet the criteria of a participating security. All PG&E Corporation’s participating securities participate in dividends on a 1:1 basis with shares of common stock.

The following is a reconciliation of PG&E Corporation’s net income and weighted average shares of common stock outstanding for calculating basic and diluted net income per share:

(in millions, except per share amounts)	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Income Available for Common Shareholders	\$ 388	\$ 293	\$ 629	\$ 517
Less: distributed earnings to common shareholders	155	139	309	278
Undistributed earnings	<u>\$ 233</u>	<u>\$ 154</u>	<u>\$ 320</u>	<u>\$ 239</u>
Common shareholders earnings				
<i>Basic</i>				
Distributed earnings to common shareholders	\$ 155	\$ 139	\$ 309	\$ 278
Undistributed earnings allocated to common shareholders	223	146	306	227
Total common shareholders earnings, basic	<u>\$ 378</u>	<u>\$ 285</u>	<u>\$ 615</u>	<u>\$ 505</u>
<i>Diluted</i>				
Distributed earnings to common shareholders	\$ 155	\$ 139	\$ 309	\$ 278
Undistributed earnings allocated to common shareholders	223	146	306	227
Total common shareholders earnings, diluted	<u>\$ 378</u>	<u>\$ 285</u>	<u>\$ 615</u>	<u>\$ 505</u>
Weighted average common shares outstanding, basic	368	356	366	355
9.50% Convertible Subordinated Notes	17	19	17	19
Weighted average common shares outstanding and participating securities, basic	<u>385</u>	<u>375</u>	<u>383</u>	<u>374</u>
Weighted average common shares outstanding, basic	368	356	366	355
Employee share-based compensation	1	1	1	1
Weighted average common shares outstanding, diluted	<u>369</u>	<u>357</u>	<u>367</u>	<u>356</u>
9.50% Convertible Subordinated Notes	17	19	17	19
Weighted average common shares outstanding and participating securities, diluted	<u>386</u>	<u>376</u>	<u>384</u>	<u>375</u>
Net earnings per common share, basic				
Distributed earnings, basic ⁽¹⁾	\$ 0.42	\$ 0.39	\$ 0.84	\$ 0.78
Undistributed earnings, basic	0.61	0.41	0.84	0.64
Total	<u>\$ 1.03</u>	<u>\$ 0.80</u>	<u>\$ 1.68</u>	<u>\$ 1.42</u>
Net earnings per common share, diluted				
Distributed earnings, diluted	\$ 0.42	\$ 0.39	\$ 0.84	\$ 0.78
Undistributed earnings, diluted	0.60	0.41	0.83	0.64
Total	<u>\$ 1.02</u>	<u>\$ 0.80</u>	<u>\$ 1.67</u>	<u>\$ 1.42</u>

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

Stock options to purchase 39,049 and 26,592 shares of PG&E Corporation common stock were excluded from the computation of diluted EPS for the three and six months ended June 30, 2009, respectively, because the exercise prices of these options were greater than the average market price of PG&E Corporation common stock during these periods. Stock options to purchase 7,285 shares of PG&E Corporation common stock were excluded from the computation of diluted EPS for the three and six months ended June 30, 2008, respectively.

PG&E Corporation reflects the preferred dividends of subsidiaries as other expense for computation of both basic and diluted EPS.

NOTE 7: DERIVATIVES AND HEDGING ACTIVITIES

Use of Derivative Instruments

The Utility faces market risk primarily related to electricity and natural gas commodity prices. The CPUC and the FERC allow the Utility to collect customer rates designed to recover the Utility's reasonable costs of providing services, including the cost to obtain and deliver electricity and natural gas. As these costs are passed through to customers, the Utility's earnings are not exposed to the commodity price risk inherent in the purchase and sale of electricity and natural gas. Therefore, substantially all of the Utility's risk management activities involving derivatives occur to reduce the volatility of commodity costs on behalf of its customers.

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

- forward contracts that commit the Utility to purchase a commodity in the future;
- swap agreements that require payments to or from counterparties based upon the difference between two prices for a predetermined contractual quantity;
- option contracts that provide the Utility with the right to buy a commodity at a predetermined price; and
- futures contracts that are exchange-traded contracts that commit the Utility to purchase a commodity or make a cash settlement at a specified price and future date.

These instruments are not held for speculative purposes and are subject to certain limitations imposed by regulatory requirements. These instruments enable the Utility to reduce the volatility associated with electricity and natural gas costs incurred by the Utility and charged to its customers through rates.

Commodity-Related Price Risk

As long as the ratemaking mechanisms discussed above remain in place and the Utility's risk management activities are carried out in accordance with CPUC directives, the Utility expects to fully recover from customers in rates all costs related to commodity-related price risk-related derivative instruments. Therefore, in accordance with the provisions of SFAS No. 71, all unrealized gains and losses associated with the fair value of these derivative instruments, including those designated as cash flow hedges, are deferred and recorded within the Utility's regulatory assets and liabilities on the Condensed Consolidated Balance Sheets. Net realized gains or losses on derivative instruments related to price risk for commodities 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 customers.

The following is a discussion of the Utility's use of derivative instruments intended to mitigate commodity-related price risk for its customers.

Electricity Procurement

The Utility obtains electricity from a diverse mix of resources, including third-party power purchase agreements, amounts allocated under DWR contracts, and its own electricity generation facilities. The Utility's third-party power purchase agreements are generally accounted for as leases, but certain third-party power purchase agreements are considered derivative instruments under SFAS No. 133 and, therefore, are recorded at fair value within the Condensed Consolidated Balance Sheets. However, derivative instruments that are eligible for the normal purchase and normal sales exception under SFAS No. 133 are not required to be recorded at fair value. Derivative instruments that require the physical delivery of commodities, where quantities purchased are expected to be used by the Utility in the normal course of business and meet certain other criteria, are eligible for the normal purchase and normal sales exception. The Utility elects to use the normal purchase and sale exception for eligible derivative instruments.

A portion of the Utility's third-party power purchase agreements contain market-based pricing terms. In order to reduce the cash flow risk associated with fluctuating electricity prices, the Utility has entered into financial swap contracts to effectively fix the price of future purchases under those power purchase agreements. These financial swaps are considered derivative instruments and are recorded at fair value within the Condensed Consolidated Balance Sheets. Some of these contracts have been designated as cash flow hedges in accordance with the requirements of SFAS No. 133.

Electric Transmission Congestion Revenue Rights

The CAISO-controlled electricity transmission grid used by the Utility to transmit power is subject to transmission constraints. As a result, the Utility is subject to financial risk associated with the cost of transmission congestion. The CAISO implemented its new day-ahead wholesale electricity market as part of its Market Redesign and Technology Update on April 1, 2009. The CAISO created congestion revenue rights ("CRRs") to allow market participants, including load serving entities, to hedge the financial risk of CAISO-imposed congestion charges in the new day-ahead market. The CAISO releases CRRs through an annual and monthly process, each of which includes an allocation phase (in which load serving entities are allocated CRRs at no cost based on the customer demand or "load" they serve), and an auction phase (in which CRRs are priced at market and available to all market participants). In the second quarter of 2009, the Utility acquired CRRs through both allocation and auction.

CRRs are considered derivative instruments and are recorded at fair value within the Condensed Consolidated Balance Sheets.

Natural Gas Procurement (Electric Portfolio)

The Utility's electric procurement portfolio is exposed to natural gas price risk primarily through the Utility-owned natural gas generating facilities, tolling agreements, and natural gas-indexed electricity procurement contracts. In order to reduce the risk to future cash flows associated with fluctuating natural gas prices, the Utility purchases financial instruments such as futures, swaps, and options. These financial instruments are considered derivative instruments and are shown at fair value within the Condensed Consolidated Balance Sheets.

Natural Gas Procurement (Small Commercial and Residential Customers)

The Utility enters into physical natural gas commodity contracts to fulfill the needs of its small commercial and residential, or "core", customers. (The Utility does not procure natural gas for industrial and large commercial or "non-core" customers.) Changes in temperature cause natural gas demand to vary daily, monthly, and seasonally. Consequently, varying volumes of gas may be purchased or sold in the monthly and, to a lesser extent, daily spot market to balance such seasonal supply and demand.

The Utility has entered into various financial instruments, such as financial swap and option contracts, intended to reduce the cash flow variability associated with fluctuating natural gas purchase prices. The Utility manages its winter exposure to natural gas prices in accordance with its CPUC-approved annual core portfolio hedging implementation plan. These contracts are considered derivative instruments that are recorded at fair value within the Condensed Consolidated Balance Sheets. A portion of these contracts have been designated as cash flow hedges in accordance with the requirements of SFAS No. 133.

Other Risk

At June 30, 2009, PG&E Corporation's Convertible Subordinated Notes had an outstanding value of \$252 million and are scheduled to mature on June 30, 2010. The holders of the Convertible Subordinated Notes are entitled to receive "pass-through dividends" determined by multiplying the cash dividend paid by PG&E Corporation per share of common stock by a number equal to the principal amount of the Convertible Subordinated Notes divided by the conversion prices. The dividend participation rights associated with the Convertible Subordinated Notes are considered to be embedded derivative instruments and, therefore, must be bifurcated from the Convertible Subordinated Notes and recorded at fair value in PG&E Corporation's Condensed Consolidated Financial Statements. Changes in fair value of the dividend participation rights are recognized in PG&E Corporation's Condensed Consolidated Statements of Income as non-operating expense or income (in Other income, net).

Volume of Derivative Activity

At June 30, 2009, the volume of PG&E Corporation's and the Utility's outstanding derivative contracts were as follows:

Underlying Product	Instruments	Contract Volumes ⁽¹⁾			
		Less Than 1 Year	1 Year But Less Than 3 Years	3 Years But Less Than 5 Years	Over 5 Years ⁽²⁾
Natural Gas ⁽³⁾ (MMBtus ⁽⁴⁾)	Forwards, Futures, and Swaps	305,796,371	172,333,439	21,545,000	-
	Options	146,042,523	105,737,360	-	-
Electricity (Megawatt-hours)	Forwards, Futures, and Swaps	3,508,656	7,500,504	5,535,512	5,408,479
	Options	28,076	11,450	70,584	597,908
	Congestion Revenue Rights	55,943,502	59,684,359	59,618,554	116,386,405
PG&E Corporation Equity Shares					
	Dividend Participation Rights	16,702,194	-	-	-

⁽¹⁾ Amounts shown reflect the total gross derivative volumes by commodity type that are expected to settle in each time period.

⁽²⁾ Derivatives in this category expire between 2014 and 2022.

⁽³⁾ Amounts shown are for the combined positions of the electric and core gas portfolios.

⁽⁴⁾ Million British Thermal Units.

Presentation of Derivative Instruments in the Financial Statements

In PG&E Corporation's and the Utility's Condensed Consolidated Balance Sheets, derivative instruments are presented on a net basis by counterparty where the right of offset exists. In accordance with the provisions of FSP on FIN 39, "Amendment of FIN 39" ("FIN 39-1"), which was adopted January 1, 2008, the net balances include outstanding cash collateral associated with derivative positions.

At June 30, 2009, PG&E Corporation's and the Utility's outstanding derivative balances were as follows:

	Gross Balances ⁽¹⁾					Total Derivative Balances on the Condensed Consolidated Balance Sheets
(in millions)	Derivatives Designated as Cash Flow Hedges ⁽²⁾	Derivatives Not Designated as Hedges	Total	Netting ⁽³⁾	Cash Collateral ⁽³⁾	
	Commodity Risk (Corporation and Utility)					
Current Assets – Prepaid expenses and other	\$ 7	\$ 42	\$ 49	\$ (10)	\$ 93	\$ 132
Other Noncurrent Assets – Other	3	121	124	(42)	32	114
Current Liabilities – Other	(141)	(236)	(377)	10	186	(181)
Noncurrent Liabilities – Other	(209)	(243)	(452)	42	67	(343)
Total Commodity Risk	\$ (340)	\$ (316)	\$ (656)	\$ -	\$ 378	\$ (278)
	Other Risk Instruments ⁽⁴⁾ (PG&E Corporation Only)					
Current Liabilities – Other	\$ -	\$ (27)	\$ (27)	\$ -	\$ -	\$ (27)
Noncurrent Liabilities – Other	-	-	-	-	-	-
Total Other Risk Instruments	\$ -	\$ (27)	\$ (27)	\$ -	\$ -	\$ (27)
Total Derivatives	\$ (340)	\$ (343)	\$ (683)	\$ -	\$ 378	\$ (305)

⁽¹⁾ See Note 8 of the Notes to the Condensed Consolidated Financial Statements for discussion of the valuation techniques used to calculate the fair value of these instruments.

⁽²⁾ As of June 30, 2009, PG&E Corporation and the Utility had cash flow hedges with expiration dates through December 2014 for energy contract-related derivative instruments.

⁽³⁾ Netting in accordance with FIN 39 ("Right of Offset") and FSP FIN 39-1.

⁽⁴⁾ This category relates to the dividend participation rights of PG&E Corporation's Convertible Subordinated Notes.

The dividend participation rights are not recoverable in customers' rates. Therefore, changes in the fair value of these instruments are recorded in PG&E Corporation's Condensed Consolidated Statements of Income and impact net income.

For the six-month period ended June 30, 2009, the gains and losses recorded on PG&E Corporation's and the Utility's derivative instruments were as follows:

(in millions)	Derivatives Designated as Cash Flow Hedges ⁽¹⁾	Derivatives Not Designated as Hedges	Total
Commodity Risk (PG&E Corporation and Utility)			
Unrealized gain/(loss) - Regulatory assets and liabilities ⁽²⁾	\$ 3	\$ (163)	\$ (160)
Realized gain/(loss) - Cost of electricity ⁽³⁾	(43)	(382)	(425)
Realized gain/(loss)- Cost of natural gas ⁽³⁾	(28)	(1)	(29)
Total Commodity Risk	\$ (68)	\$ (546)	\$ (614)
Other Risk Instruments ⁽⁴⁾ (PG&E Corporation Only)			
Other income, net	\$ -	\$ 1	\$ 1
Total Other Risk	\$ -	\$ 1	\$ 1

⁽¹⁾ As a result of applying the provisions of SFAS No. 71, unrealized gains and losses on cash flow hedges are recorded to regulatory assets or liabilities, rather than being deferred in accumulated other comprehensive income.

⁽²⁾ As a result of applying the provisions of SFAS No. 71, unrealized gains and losses on the commodity risk-related derivative instrument are recorded to regulatory assets or liabilities, rather than being recorded to the Condensed Consolidated Statements of Income. Additionally, these amounts exclude the impact of cash collateral postings.

⁽³⁾ These amounts are fully passed through to customers in rates. Accordingly, net income was not impacted by realized amounts on these instruments.

⁽⁴⁾ This category relates to the dividend participation rights of PG&E Corporation's Convertible Subordinated Notes.

Cash inflows and outflows associated with the settlement of all derivative instruments are recognized in operating cash flows on PG&E Corporation's and the Utility's Condensed Consolidated Statements of Cash Flows.

The majority of the Utility's commodity risk-related derivative instruments 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 were to fall below investment grade, the Utility would be required to immediately post additional cash to fully collateralize its net liability derivative positions.

At June 30, 2009, the additional cash collateral the Utility would be required to post if its credit-risk-related contingent features were triggered is as follows:

(in millions)

Derivatives in a Liability Position with Credit-Risk-Related Contingencies That Are Not Fully Collateralized	\$	(654)
Related Derivatives in an Asset Position		64
Collateral Posting in the Normal Course of Business Related to These Derivatives		132
Net Position of Derivative Contracts/Additional Collateral Posting Requirements ⁽¹⁾	\$	(458)

⁽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

SFAS No. 157 requires an entity to determine the fair value of certain assets and liabilities based on assumptions that market participants would use in pricing the assets or liabilities. SFAS No. 157 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value and gives precedence to observable inputs in determining fair value. An instrument's level within the hierarchy is based on the lowest level of any significant input to the fair value measurement. See Note 12 of the Notes to the Consolidated Financial Statements in the 2008 Annual Report for further discussion of fair value measurements.

The following table sets forth the fair value hierarchy by level of PG&E Corporation's and the Utility's recurring fair value financial instruments at June 30, 2009. PG&E Corporation's and the Utility's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

PG&E Corporation				
Fair Value Measurements at June 30, 2009				
(in millions)	Level 1	Level 2	Level 3	Total
Assets:				
Money market investments (held by PG&E Corporation)	\$ 176	\$ -	\$ 5	\$ 181
Nuclear decommissioning trusts				
Equity securities	977	-	5	982
U.S. government and agency issues	590	48	-	638
Municipal bonds and other	-	178	-	178
Nuclear decommissioning trusts Total ⁽¹⁾	1,567	226	5	1,798
Rabbi trusts-Equity	70	-	-	70
Long-term disability trust				
Equity	74	-	57	131
Corporate Debt Securities	-	-	24	24
Long-term disability trust Total	74	-	81	155
Assets Total	\$ 1,887	\$ 226	\$ 91	\$ 2,204
Liabilities:				
Dividend participation rights	\$ -	\$ -	\$ 27	\$ 27
Price risk management instruments ⁽²⁾	(22)	111	189	278
Other	-	-	3	3
Liabilities Total	\$ (22)	\$ 111	\$ 219	\$ 308

⁽¹⁾ Excludes deferred taxes on appreciation of investment value.

⁽²⁾ Balances include the impact of netting adjustments in accordance with the requirements of FIN 39-1 of \$129 million to Level 1, \$81 million to Level 2, and \$168 million to Level 3.

Utility				
Fair Value Measurements at June 30, 2009				
(in millions)	Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trusts				
Equity securities	\$ 977	\$ -	\$ 5	\$ 982
U.S. government and agency issues	590	48	-	638
Municipal bonds and other	-	178	-	178
Nuclear decommissioning trusts Total ⁽¹⁾	1,567	226	5	1,798
Long-term disability trust				
Equity	74	-	57	131
Corporate Debt Securities	-	-	24	24
Long-term disability trust Total	74	-	81	155
Assets Total	\$ 1,641	\$ 226	\$ 86	\$ 1,953
Liabilities:				
Price risk management instruments ⁽²⁾	\$ (22)	\$ 111	\$ 189	\$ 278
Other	-	-	3	3
Liabilities Total	\$ (22)	\$ 111	\$ 192	\$ 281

⁽¹⁾ Excludes deferred taxes on appreciation of investment value.

⁽²⁾ Balances include the impact of netting adjustments in accordance with the requirements of FIN 39-1 of \$129 million to Level 1, \$81 million to Level 2, and \$168 million to Level 3.

PG&E Corporation's and the Utility's fair value measurements incorporate various factors, such as nonperformance and credit risk adjustments. At June 30, 2009, the nonperformance and credit risk adjustment represented approximately 1% of the net price risk management value. PG&E Corporation and the Utility utilize a mid-market pricing convention (the mid-point between bid and ask prices) as a practical expedient in valuing the majority of its derivative assets and liabilities at fair value.

Financial Instruments

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

- The fair values of cash and cash equivalents, restricted cash and deposits, net accounts receivable, price risk management assets and liabilities, short-term borrowings, accounts payable, customer deposits, and the Utility's variable rate pollution control bond loan agreements approximate their carrying values at June 30, 2009 and December 31, 2008.
- The fair values of the Utility's fixed rate senior notes, fixed rate pollution control bond loan agreements, PG&E Corporation's 9.50% Convertible Subordinated Notes, and the ERBs issued by PERF were based on quoted market prices at June 30, 2009.

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

(in millions)	At June 30, 2009		At December 31, 2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Debt (Note 4):				
PG&E Corporation	\$ 602	\$ 1,024	\$ 280	\$ 739
Utility	8,690	9,116	8,740	9,134
Energy recovery bonds (Note 4)	1,409	1,446	1,583	1,564

The Utility classifies its investments held in the nuclear decommissioning trust as “available-for-sale” in accordance with SFAS No. 115. As the day-to-day investing activities of the trusts are managed by external investment managers, the Utility is unable to assert that it has the intent and ability to hold investments to maturity. Therefore, all unrealized losses are considered other-than-temporary impairments. Gains or losses on the nuclear decommissioning trust investments are refundable or recoverable, respectively, from customers. Therefore, trust earnings are deferred and included in the regulatory liability for recoveries in excess of asset retirement obligations. There is no impact on the Utility’s earnings or accumulated other comprehensive income. (See Note 3 of the Notes to the Condensed Consolidated Financial Statements.)

The following table provides a summary of the fair value of the investments held in the Utility’s nuclear decommissioning trusts:

	<u>Maturity Date</u>	<u>Amortized Cost</u>	<u>Total Unrealized Gains</u>	<u>Total Unrealized Losses</u>	<u>Estimated (1) Fair Value</u>
(in millions)					
Six months ended June 30, 2009					
U.S. government and agency issues	2009- 2038	\$ 585	\$ 59	\$ (2)	\$ 642
Municipal bonds and other	2009- 2049	176	3	(5)	174
Equity securities		589	399	(6)	982
Total		<u>\$ 1,350</u>	<u>\$ 461</u>	<u>\$ (13)</u>	<u>\$ 1,798</u>

(1) Excludes deferred taxes on appreciation of investment value.

The cost of debt and equity securities sold is determined by specific identification. The following table provides a summary of the activity for the debt and equity securities:

	<u>Six Months Ended June 30, 2009</u>	<u>Year Ended December 31, 2008</u>
(in millions)		
Gross realized gains on sales of securities held as available-for-sale	12	30
Gross realized losses on sales of securities held as available-for-sale	(50)	(142)

In general, investments held in the nuclear decommissioning trust are exposed to various risks, such as interest rate, credit and market volatility risks. Due to the level of risk associated with certain investment securities, it is reasonably possible that changes in the market values of investment securities could occur in the near term, and such changes could materially affect the trusts’ fair value.

Level 3 Rollforward

The following table is a reconciliation of changes in fair value of PG&E Corporation’s instruments that have been classified as Level 3 in the fair value hierarchy for the six-month period ended June 30, 2009:

	<u>PG&E Corporation Only</u>			<u>PG&E Corporation and the Utility</u>					
	<u>Money Market</u>	<u>Dividend Participation Rights</u>	<u>Price Risk Management</u>	<u>Nuclear Decommission- ing Trusts Equity (1)</u>	<u>Long- term Disability Equity</u>	<u>Long- term Disability Corp. Debt Securities</u>	<u>Other</u>	<u>Total</u>	
(in millions)									
Asset (Liability) Balance as of January 1, 2009	\$ 12	\$ (42)	\$ (156)	\$ 5	\$ 54	\$ 24	\$ (2)	\$ (105)	
Realized and unrealized gains (losses):									
Included in earnings	-	1	-	-	3	-	-	4	
Included in regulatory assets and liabilities or balancing accounts	-	-	(33)	-	-	-	(1)	(34)	
Purchases, issuances, and settlements	(7)	14	-	-	-	-	-	7	
Transfers in to Level 3	-	-	-	-	-	-	-	-	
Asset (Liability) Balance as of June 30, 2009	<u>\$ 5</u>	<u>\$ (27)</u>	<u>\$ (189)</u>	<u>\$ 5</u>	<u>\$ 57</u>	<u>\$ 24</u>	<u>\$ (3)</u>	<u>\$ (128)</u>	

⁽¹⁾ Excludes deferred taxes on appreciation of investment value.

Earnings for the period were impacted by a \$4 million unrealized gain relating to assets or liabilities still held at June 30, 2009.

The following table is a reconciliation of changes in fair value of instruments that have been classified as Level 3 in the fair value hierarchy for the three-month period ended June 30, 2009:

	PG&E Corporation Only			PG&E Corporation and the Utility				
(in millions)	Money Market	Dividend Participation Rights	Price Risk Management	Nuclear Decommissioning Trusts Equity ⁽¹⁾	Long-term Disability Equity	Long-term Disability Corp. Debt Securities	Other	Total
Asset (Liability) Balance as of April 1, 2009	\$ 8	\$ (33)	\$ (176)	\$ 4	\$ 47	\$ 24	\$ (1)	\$ (127)
Realized and unrealized gains (losses):								
Included in earnings	-	(1)	-	-	10	-	-	9
Included in regulatory assets and liabilities or balancing accounts	-	-	(13)	1	-	-	(2)	(14)
Purchases, issuances, and settlements	(3)	7	-	-	-	-	-	4
Transfers in to Level 3	-	-	-	-	-	-	-	-
Asset (Liability) Balance as of June 30, 2009	\$ 5	\$ (27)	\$ (189)	\$ 5	\$ 57	\$ 24	\$ (3)	\$ (128)

⁽¹⁾Excludes deferred taxes on appreciation of investment value.

Earnings for the period were impacted by a \$9 million unrealized gain relating to assets or liabilities still held at June 30, 2009.

PG&E Corporation and the Utility did not have any nonrecurring financial measurements within the scope of SFAS No. 157 at June 30, 2009.

NOTE 9: RELATED PARTY AGREEMENTS AND TRANSACTIONS

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

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

(in millions)	<u>Three Months Ended</u>		<u>Six Months Ended</u>	
	<u>June 30,</u>		<u>June 30,</u>	
	<u>2009</u>	<u>2008</u>	<u>2009</u>	<u>2008</u>
Utility revenues from:				
Administrative services provided to PG&E Corporation	\$ 1	\$ 1	\$ 2	\$ 2
Utility employee benefit due from PG&E Corporation	-	-	-	-
Utility expenses from:				
Administrative services received from PG&E Corporation	\$ 14	\$ 28	\$ 33	\$ 52
Utility employee benefit due to PG&E Corporation	3	4	9	11

At June 30, 2009 and December 31, 2008, the Utility had a receivable of \$27 million and \$29 million, respectively, from PG&E Corporation included in Accounts receivable – Related parties and Other Noncurrent Assets – Related parties receivable on the Utility's Condensed Consolidated Balance Sheets, and a payable of \$11 million and \$25 million, respectively, to PG&E Corporation included in Accounts payable – Related parties on the Utility's Condensed Consolidated Balance Sheets.

NOTE 10: RESOLUTION OF REMAINING CHAPTER 11 DISPUTED CLAIMS

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

While the FERC and judicial proceedings have been pending, the Utility entered into a number of settlements 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 proceeds from these settlements, after deductions for contingencies based on the outcome of the various refund offset and interest issues being considered by the FERC, will continue to be refunded to customers in rates. Additional settlement discussions with other electricity suppliers are ongoing. Any net refunds, claim offsets, or other credits that the Utility receives from energy suppliers through resolution of the remaining disputed claims, either through settlement or the conclusion of the various FERC and judicial proceedings, will also be credited to customers.

The following table presents the changes in the remaining disputed claims liability and interest accrued from December 31, 2008 to June 30, 2009:

(in millions)	
Balance at December 31, 2008	\$ 1,750
Interest accrued	34
Less: Settlements	(32)
Balance at June 30, 2009	<u>\$ 1,752</u>

At June 30, 2009, the Utility's net disputed claims liability was \$1,752 million, consisting of \$1,552 million of remaining disputed claims (classified on the Condensed Consolidated Balance Sheets within Accounts payable – Disputed claims and customer refunds) and interest accrued at the FERC-ordered rate of \$694 million (classified on the Condensed Consolidated Balance Sheets within Interest payable) offset by accounts receivable from the CAISO and the PX of \$494 million (classified on the Condensed Consolidated Balance Sheets within Accounts receivable – Customers).

In connection with the Utility's proceeding under Chapter 11, the Utility established an escrow account to fund future settlements and for the payment of disputed claims, which is included within Restricted cash on the Condensed Consolidated Balance Sheets. At June 30, 2009, the Utility held \$1,214 million in escrow, including interest earned, for payment of the remaining net disputed claims.

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

On April 10, 2009, the Utility and the PX entered into a proposed agreement under which the Utility agreed to transfer \$700 million to the PX from the Utility's escrow account. The agreement has been approved by the FERC, the bankruptcy court presiding over the PX's bankruptcy case, and the bankruptcy court that retains jurisdiction over the Utility's Chapter 11 proceeding. The orders issued by the FERC and the bankruptcy court presiding over the PX's bankruptcy case have become final. The order issued by the bankruptcy court that retains jurisdiction over the Utility's Chapter 11 proceeding will become final on August 7, 2009, assuming no appeal is filed. After the order becomes final, the Utility will transfer \$700 million to the PX and the Utility's liability for the remaining net disputed claims will be reduced. To protect the Utility against the imposition of double liability, the agreement provides that to the extent that both the PX and an individual electricity supplier have filed claims relating to the same transaction, such claim will be paid by the Utility only once, either to the PX or directly to the electricity supplier, as may be ordered by the FERC or the court of competent jurisdiction.

PG&E Corporation and the Utility are unable to predict when the FERC or judicial proceedings that are still pending will be resolved, and the amount of any potential refunds that the Utility may receive or the amount of disputed claims, including interest, that the Utility will be required to pay.

NOTE 11: COMMITMENTS AND CONTINGENCIES

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

Commitments

Utility

Third-Party Power Purchase Agreements

As part of the ordinary course of business, the Utility enters into various agreements to purchase power and electric capacity. The price of purchased power may be fixed or variable. Variable pricing is generally based on the current market price of either gas or electricity at the date of purchase. Forward prices at June 30, 2009 are used to determine the undiscounted future expected payments for contracts with variable pricing terms. At June 30, 2009, the undiscounted future expected power purchase agreement payments were as follows:

(in millions)	
2009	\$ 1,093
2010	2,158
2011	2,189
2012	2,206
2013	2,160
Thereafter	21,278
Total	\$ 31,084

Payments made by the Utility under power purchase agreements amounted to \$1,154 million and \$2,284 million for the six months ended June 30, 2009 and June 30, 2008, respectively. The amounts above do not include payments related to the DWR purchases for the benefit of the Utility's customers, as the Utility only acts as an agent for the DWR.

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

(in millions)	
2009	\$ 29
2010	50
2011	50
2012	50
2013	50
Thereafter	206
Total fixed capacity payments	435
Less: Amount representing interest	100
Present value of fixed capacity payments	\$ 335

Minimum lease payments associated with the lease obligation are included in Cost of electricity on PG&E Corporation's and the Utility's Condensed Consolidated Statements of Income. In accordance with SFAS No. 71, the timing of the Utility's recognition of the lease expense conforms to the ratemaking treatment for the Utility's recovery of the cost of electricity. The QF contracts that are treated as capital leases expire between April 2014 and September 2021.

Capacity payments are based on the QF's total available capacity and contractual capacity commitment. Capacity payments may be adjusted if the QF exceeds or fails to meet performance requirements specified in the applicable power purchase agreement.

Natural Gas Supply and Transportation Commitments

The Utility purchases natural gas directly from producers and marketers in both Canada and the United States to serve its core customers. The contract lengths and natural gas sources of the Utility's portfolio of natural gas procurement contracts can fluctuate based on market conditions. The Utility also contracts for natural gas transportation to transport natural gas from the points at which the Utility takes delivery of natural gas (typically in Canada and the southwestern United States) to the points at which the Utility's natural gas transportation system begins.

At June 30, 2009, the Utility's undiscounted obligations for natural gas purchases and gas transportation services were as follows:

(in millions)	
2009	\$ 381
2010	438
2011	121
2012	49
2013	42
Thereafter	157
Total	\$ 1,188

Payments for natural gas purchases and gas transportation services amounted to \$737 million and \$1,589 million for the six months ended June 30, 2009 and June 30, 2008, respectively.

Nuclear Fuel Agreements

The Utility has entered into several purchase agreements for nuclear fuel. These agreements have terms ranging from 1 to 16 years and are intended to ensure long-term fuel supply. The contracts for uranium, conversion and enrichment services provide for 100% coverage of reactor requirements through 2012, while contracts for fuel fabrication services provide for 100% coverage of reactor requirements through 2011. The Utility relies on a number of international producers of nuclear fuel in order to diversify its sources and provide security of supply. Pricing terms are also diversified, ranging from market-based prices to base prices that are escalated using published indices. New agreements are primarily based on forward market pricing and will begin to impact nuclear fuel costs starting in 2010.

At June 30, 2009, the undiscounted obligations under nuclear fuel agreements were as follows:

(in millions)	
2009	\$ 151
2010	101
2011	100
2012	88
2013	118
Thereafter	1,181
Total	\$ 1,739

Payments for nuclear fuel amounted to \$61 million and \$26 million for the six months ended June 30, 2009 and June 30, 2008, respectively.

Contingencies

PG&E Corporation

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

Utility

Spent Nuclear Fuel Storage Proceedings

As part of the Nuclear Waste Policy Act of 1982, Congress authorized the U.S. Department of Energy (“DOE”) and electric utilities with commercial nuclear power plants to enter into contracts under which the DOE would be required to dispose of the utilities’ spent nuclear fuel and high-level radioactive waste no later than January 31, 1998, in exchange for fees paid by the utilities. In 1983, the DOE entered into a contract with the Utility to dispose of nuclear waste from the Utility’s two nuclear generating units at the Diablo Canyon Power Plant (“Diablo Canyon”) and its retired nuclear facility at Humboldt Bay (“Humboldt Bay Unit 3”). The DOE failed to develop a permanent storage site by January 31, 1998.

The Utility believes that the existing spent fuel pools at Diablo Canyon (which include newly constructed temporary storage racks) have sufficient capacity to enable the Utility to operate Diablo Canyon until approximately 2010 for Unit 1 and 2011 for Unit 2. Because the DOE failed to develop a permanent storage site, the Utility obtained a permit from the Nuclear Regulatory Commission (“NRC”) to build an on-site dry cask storage facility to store spent fuel through at least 2024. The construction of the dry cask storage facility is complete and the initial movement of spent nuclear fuel to dry cask storage began in June 2009.

After various parties appealed the NRC’s issuance of the permit, the U.S. Court of Appeals for the Ninth Circuit (“Ninth Circuit”) issued a decision in 2006 requiring the NRC to issue a supplemental environmental assessment report on the potential environmental consequences in the event of a terrorist attack at Diablo Canyon, as well as to review other contentions raised by the appealing parties related to potential terrorism threats. In August 2007, the NRC staff issued a final supplemental environmental assessment report concluding that there would be no significant environmental impacts from potential terrorist acts directed at the Diablo Canyon storage facility.

In October 2008, the NRC rejected the final contention that had been made during the appeal. The appellant has filed a petition for review of the NRC’s order in the Ninth Circuit. On December 31, 2008, the appellate court granted the Utility’s request to intervene in the proceeding. The Utility’s brief on appeal was filed on April 8, 2009. No date has been set for oral argument.

As a result of the DOE’s failure to build a national repository for nuclear waste, the Utility and other nuclear power plant owners sued the DOE to recover costs that they incurred to build on-site spent nuclear fuel storage facilities. The Utility seeks to recover \$92 million of costs that it incurred through 2004. The DOE disputes the calculation of the recoverable amount, conceding only that the Utility is entitled to recover \$82 million of costs incurred through 2004. The U.S. Court of Federal Claims has ordered the trial for the remainder of the Utility’s claim to begin on October 15, 2009.

PG&E Corporation and the Utility are unable to predict the amount that the Utility may ultimately receive for costs incurred through 2004. The Utility will also seek to recover costs incurred after 2004. Amounts recovered from the DOE will be credited to customers through rates.

Energy Efficiency Programs and Incentive Ratemaking

The CPUC previously established an incentive ratemaking mechanism applicable to the California investor-owned utilities’ implementation of their energy efficiency programs funded for the 2006-2008 and 2009-2011 program cycles. On December 18, 2008, based on their first interim claims, the CPUC awarded interim incentive earnings to the utilities for their 2006-2007 program performance. In the fourth quarter of 2008, the Utility recognized a CPUC award of \$41.5 million for the Utility’s energy efficiency program performance in 2006-2007. Under the existing incentive ratemaking mechanism, the maximum amount of revenue that the Utility could earn and the maximum amount that the Utility could be required to reimburse customers over the 2006-2008 program cycle is \$180 million.

On May 21, 2009, the Utility, San Diego Gas & Electric Company, Southern California Gas Company, and the Natural Resources Defense Council, jointly requested that the CPUC approve a proposed settlement to resolve the utilities’ interim claims for 2008 program performance and their final 2006-2008 true-up incentive claims. On July 10, 2009, the Utility submitted calculations, based on the methodology included in the proposed settlement, indicating that the Utility would be entitled to earn the remaining amount of the maximum incentives that could be earned for the 2006-2008 period. Based on the holdback amount proposed in the settlement, the Utility would be entitled to receive \$76.6 million in incentive earnings and an additional \$61.9 million would be held back and subject to verification in the final 2006-2008 true-up process to be completed in 2010.

The assigned administrative law judge has ruled that there will be no hearings on the settlement proposal. Nevertheless, in accordance with the current incentive claim process, the judge will permit the CPUC’s Energy Division to issue its second verification report analyzing the utilities’ 2008 energy efficiency program performance. The draft verification report is expected to be issued shortly and the parties will then be allowed to provide comments on the draft. It is uncertain what effect, if any, the issuance of the verification report will have on the likelihood of the proposed settlement becoming effective. The CPUC is expected to issue a final decision to resolve the 2006-2008 incentive claims before the end of 2009. Whether the proposed settlement will be approved and the amounts of any interim and final claims that may be awarded to the Utility are uncertain at this time.

Nuclear Insurance

The Utility has several types of nuclear insurance for the two nuclear operating units at Diablo Canyon and for its retired nuclear generation facility at Humboldt Bay Unit 3. The Utility has insurance coverage for property damages and business interruption losses as a member of Nuclear Electric Insurance Limited (“NEIL”). NEIL is a mutual insurer owned by utilities with nuclear facilities. NEIL provides property damage and business interruption coverage of up to \$3.24 billion per incident for Diablo Canyon. In addition, NEIL provides \$131 million of property damage insurance for Humboldt Bay Unit 3. Under this insurance, if any nuclear generating facility insured by NEIL suffers a catastrophic loss causing a prolonged outage, the Utility may be required to pay an additional premium of up to \$39.3 million per one-year policy term.

NEIL also provides coverage for damages caused by acts of terrorism at nuclear power plants. Under the Terrorism Risk Insurance Program Reauthorization Act of 2007 (“TRIPRA”), acts of terrorism may be “certified” by the Secretary of the Treasury. For a certified act of terrorism, NEIL can obtain compensation from the federal government and will provide up to the full policy limits to the Utility for an insured loss. If one or more non-certified acts of terrorism cause property damage covered under any of the nuclear insurance policies issued by NEIL to any NEIL member, the maximum recovery under all those nuclear insurance policies may not exceed \$3.24 billion within a 12-month period plus the additional amounts recovered by NEIL for these losses from reinsurance. (TRIPRA extends the Terrorism Risk Insurance Act of 2002 through December 31, 2014.)

Under the Price-Anderson Act, public liability claims from a nuclear incident are limited to \$12.5 billion. As required by the Price-Anderson Act, the Utility purchased the maximum available public liability insurance of \$300 million for Diablo Canyon. The balance of the \$12.5 billion of liability protection is covered by a loss-sharing program among utilities owning nuclear reactors. Under the Price-Anderson Act, owner participation in this loss-sharing program is required for all owners of nuclear reactors that are licensed to operate, designed for the production of electrical energy, and have a rated capacity of 100 MW or higher. If a nuclear incident results in costs in excess of \$300 million, then the Utility may be responsible for up to \$117.5 million per reactor, with payments in each year limited to a maximum of \$17.5 million per incident until the Utility has fully paid its share of the liability. Since Diablo Canyon has two nuclear reactors, each with a rated capacity of over 100 MW, the Utility may be assessed up to \$235 million per incident, with payments in each year limited to a maximum of \$35 million per incident. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due on or before October 29, 2013.

In addition, the Utility has \$53.3 million of liability insurance for Humboldt Bay Unit 3 and has a \$500 million indemnification from the NRC for public liability arising from nuclear incidents, covering liabilities in excess of the \$53.3 million of liability insurance.

Environmental Matters

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

The cost of environmental remediation is difficult to estimate. The Utility records an environmental remediation liability when site assessments indicate remediation is probable and it can estimate a range of possible clean-up costs. The Utility reviews its remediation liability on a quarterly basis. The liability is an estimate of costs for site investigations, remediation, operations and maintenance, monitoring, and site closure using current technology, and considering enacted laws and regulations, experience gained at similar sites, and an assessment of the probable level of involvement, and financial condition of other potentially responsible parties. Unless there is a better estimate within this range of possible costs, the Utility records the costs at the lower end of this range. The Utility estimates the upper end of this cost range using possible outcomes that are least favorable to the Utility. It is reasonably possible that a change in these estimates may occur in the near term due to uncertainty concerning the Utility’s responsibility, the complexity of environmental laws and regulations, and the selection of compliance alternatives.

The Utility had an undiscounted and gross environmental remediation liability of \$594 million at June 30, 2009, and \$568 million at December 31, 2008. The \$594 million accrued at June 30, 2009 consists of:

- \$49 million for remediation at the Utility’s natural gas compressor site located near Hinkley, California;
- \$158 million for remediation at the Utility’s natural gas compressor site located in Topock, Arizona, near the California border;
- \$86 million related to remediation at divested generation facilities;
- \$248 million related to remediation costs for the Utility’s generation and other facilities, third-party disposal sites, and manufactured gas plant sites owned by the Utility or third parties (including those sites that are the subject of remediation orders by environmental agencies or claims by the current owners of the former manufactured gas plant sites); and
- \$53 million related to remediation costs for fossil decommissioning sites.

Of the \$594 million environmental remediation liability, \$139 million has been included in prior rate setting proceedings. The Utility expects that an additional amount of \$369 million will be recoverable in future rates. The Utility also recovers its costs from insurance carriers and from other third parties whenever possible. Any amounts collected in excess of the Utility's ultimate obligations may be subject to refund to customers. Environmental remediation associated with the Hinkley natural gas compressor site is not recoverable from customers.

The Utility's undiscounted future costs could increase to as much as \$1 billion if the other potentially responsible parties are not financially able to contribute to these costs or if the extent of contamination or necessary remediation is greater than anticipated, and could increase further if the Utility chooses to remediate beyond regulatory requirements. The amount of \$1 billion does not include any estimate for any potential costs of remediation at former manufactured gas plant sites owned by others unless the Utility has assumed liability for the site, the current owner has asserted a claim against the Utility, or the Utility has otherwise determined it is probable that a claim will be asserted.

The Utility's Diablo Canyon power plant uses a process known as "once-through cooling" that takes in water from the ocean to cool the generating facility and discharges the heated water back into the ocean. There is continuing uncertainty about the status of state and federal regulations issued under Section 316(b) of the Clean Water Act, which require that cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts. In July 2004, the U.S. Environmental Protection Agency ("EPA") issued regulations to implement Section 316(b) intended to reduce impacts to aquatic organisms by establishing a set of performance standards for cooling water intake structures. These regulations provided each facility with a number of compliance options and permitted site-specific variances based on a cost-benefit analysis. The EPA regulations also allowed the use of environmental mitigation or restoration to meet compliance requirements in certain cases.

Various parties separately challenged the EPA's regulations, and in January 2007, the U.S. Court of Appeals for the Second Circuit ("Second Circuit") issued a decision holding that environmental restoration cannot be used as a compliance option and that site-specific compliance variances based on a cost-benefit test could not be used. The Second Circuit remanded significant provisions of the regulations to the EPA for reconsideration and in July 2007, the EPA suspended its regulations. The U.S. Supreme Court granted review of the cost-benefit question and in April 2009 issued a decision reversing the Second Circuit and finding permissible the EPA's use of cost-benefit analysis to set national compliance standards for cooling water intake systems and variances to those standards. The EPA is currently revising its regulations regarding cooling water intake systems. In response to the EPA regulations, the California State Water Resources Control Board ("Water Board") issued an initial proposed policy to address once-through cooling in June 2006. Since that time, the Water Board reviewed and revised its proposal in response to comments from various California agencies and concerned stakeholders. The Water Board's current draft proposal, issued in June 2009, requires fossil and nuclear plants to either retrofit to closed cycle cooling or install operational and structural controls to achieve a similar reduction and provides a compliance timeframe for each once-through-cooled facility. The proposal also requires the development of a once-through cooling alternatives study for nuclear plants and requires that Diablo Canyon be in compliance with the policy by December 31, 2021, unless compliance would conflict with a nuclear safety requirement or the cost of compliance is wholly disproportionate to the benefits.

Depending on the form of the final regulations that may ultimately be adopted by the EPA or the Water Board, the Utility may incur significant capital expense to comply with the final regulations, which the Utility would seek to recover through rates. If either the final regulations adopted by the EPA or the Water Board require the installation of cooling towers at Diablo Canyon, and if installation of such cooling towers is not technically or economically feasible, the Utility may be forced to cease operations at Diablo Canyon and may incur a material charge.

Tax Matters

As a result of the October 2008 Internal Revenue Service ("IRS") audit settlement of tax years 2001 through 2004, PG&E Corporation received a cash refund of \$294 million in March 2009 (after applying \$80 million of the refund to make a 2008 estimated income tax payment).

On June 8, 2009, the IRS executed a closing agreement to resolve refund claims related to the 1998 and 1999 tax years after the U.S. Congress' Joint Committee on Taxation indicated that it took no exception to the settlement. The refund of tax and interest from the IRS as a result of the settlement is approximately \$310 million. In July 2009, PG&E Corporation and the Utility received the majority of this refund from the IRS. The remaining amount is expected in the third quarter of 2009. PG&E Corporation and the Utility recognized after tax income of \$56 million in the second quarter of 2009 as a result of this settlement.

Currently, PG&E Corporation has approximately \$60 million of federal capital loss carry forwards based on tax returns as filed and the resolution of the IRS audit of tax years 2001 through 2004. Of the \$60 million federal capital loss carry forwards, approximately \$20 million will expire if not used by the end of 2009.

The IRS is currently auditing tax years 2005 through 2007. In addition, PG&E Corporation began participating in the IRS's Compliance Assurance Process ("CAP") in 2008, a real-time audit process intended to expedite the resolution of issues raised during audits. To date, no material adjustments have been proposed for either the 2005 through 2007 audit or for the 2008 CAP, except for adjustments to reflect the rollover impact of items settled from prior audits. In March 2009, PG&E Corporation and the IRS signed an agreement to permit PG&E Corporation's participation in the 2009 CAP.

The California Franchise Tax Board is currently auditing PG&E Corporation's 2004 and 2005 combined California income tax returns. To date, no material adjustments have been proposed. In addition to the federal capital loss carry forwards, PG&E Corporation has approximately \$200 million of California capital loss carry forwards based on tax returns as filed, the majority of which will expire if not used by the end of 2009.

For discussion of unrecognized tax benefits, see Note 10 of the Notes to the Consolidated Financial Statements in the 2008 Annual Report. PG&E Corporation and the Utility do not expect the total amount of unrecognized tax benefits to change significantly within the next 12 months.

Legal Matters

PG&E Corporation and the Utility are subject to various laws and regulations and, in the normal course of business, PG&E Corporation and the Utility are named as parties in a number of claims and lawsuits.

In accordance with SFAS No. 5, "Accounting for Contingencies," PG&E Corporation and the Utility make a provision for a liability when it is both probable that a liability has been incurred and the amount of the loss can be reasonably estimated. These accruals, and the estimates of any additional reasonably possible losses, are reviewed quarterly and are adjusted to reflect the impacts of negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. In assessing such contingencies, PG&E Corporation's and the Utility's policy is to exclude anticipated legal costs.

The accrued liability for legal matters is included in PG&E Corporation's and the Utility's Current Liabilities – Other in the Condensed Consolidated Balance Sheets, and totaled \$64 million at June 30, 2009 and \$72 million at December 31, 2008. After consideration of these accruals, PG&E Corporation and the Utility do not expect that losses associated with legal matters would have a material adverse impact on their financial condition and results of operations.

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 whose primary purpose is to hold interests in energy-based businesses. PG&E Corporation conducts its business principally through Pacific Gas and Electric Company ("Utility"), a public utility operating in northern and central California. The Utility engages in the businesses of electricity and natural gas distribution; electricity generation, procurement, and transmission; and natural gas procurement, transportation, and storage. PG&E Corporation became the holding company of the Utility and its subsidiaries on January 1, 1997. Both PG&E Corporation and the Utility are headquartered in San Francisco, California.

The Utility served 5.1 million electricity distribution customers and 4.3 million natural gas distribution customers at June 30, 2009. The Utility had \$41.9 billion in assets at June 30, 2009 and generated revenues of \$6.6 billion in the six months ended June 30, 2009.

The Utility is regulated primarily by the California Public Utilities Commission ("CPUC") and the Federal Energy Regulatory Commission ("FERC"). The Utility generates revenues mainly through the sale and delivery of electricity and natural gas at rates set by the CPUC and the FERC. Rates are set to permit the Utility to recover its authorized "revenue requirements" from customers. Revenue requirements are designed to allow the Utility an opportunity to recover its reasonable costs of providing utility services, including a return of, and a fair rate of return on, its investment in Utility facilities ("rate base"). Pending regulatory proceedings that could result in rate changes and affect the Utility's revenues are discussed in PG&E Corporation's and the Utility's combined Annual Report on Form 10-K for the year ended December 31, 2008, which, together with the information incorporated by reference into such report, is referred to in this quarterly report as the "2008 Annual Report." Significant developments that have occurred since the 2008 Annual Report was filed with the Securities and Exchange Commission ("SEC") are discussed in this Quarterly Report on Form 10-Q.

This is a combined quarterly report of PG&E Corporation and the Utility and includes separate Condensed Consolidated Financial Statements for each of these two entities. 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, as well as the accounts of variable interest entities for which the Utility absorbs a majority of the risk of loss or gain. This combined Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") of PG&E Corporation and the Utility should be read in conjunction with the Condensed Consolidated Financial Statements and the Notes to the Condensed Consolidated Financial Statements included in this quarterly report, as well as the MD&A, the audited Consolidated Financial Statements, and the Notes to the Consolidated Financial Statements incorporated by reference in the 2008 Annual Report.

Summary of Changes in Earnings per Common Share and Income Available for Common Shareholders for the Three and Six Months Ended June 30, 2009

PG&E Corporation's diluted earnings per common share ("EPS") for the three months ended June 30, 2009 was \$1.02 compared to \$0.80 for the same period in 2008. For the six months ended June 30, 2009, PG&E Corporation's diluted EPS was \$1.67 compared to \$1.42 for the same period in 2008. PG&E Corporation's income available for common shareholders for the three months ended June 30, 2009 increased by \$95 million, or 32%, to \$388 million, compared to \$293 million for the same period in 2008. For the six months ended June 30, 2009, income available for common shareholders increased by \$112 million, or 22%, to \$629 million, compared to \$517 million for the same period in 2008.

The increase in diluted EPS and income available for common shareholders for the three and six months ended June 30, 2009, as compared to the same periods in 2008, is due to the Utility's return on equity ("ROE") on higher authorized capital investments representing an increase of \$23 million and \$49 million, respectively, income of \$28 million representing the recovery of costs related to the Utility's hydroelectric generation facilities, and an income benefit of \$56 million as a result of a tax settlement regarding refund claims related to the 1998 and 1999 tax years. In addition, the Utility's income for the six months ended June 30, 2009, reflects a benefit of \$24 million, as compared to the same period in the prior year when the Utility incurred higher storm and outage expenses. These increases to income available for common shareholders for the three and six months ended June 30, 2009 were partially offset by decreases of \$11 million and \$16 million, respectively, for costs incurred to perform accelerated natural gas leak surveys and associated remedial work, and by a decrease of \$8 million attributable to higher environmental remediation costs as compared to the same periods in 2008. Additionally, income available for common shareholders for the six months ended June 30, 2009, decreased by \$6 million as the Utility incurred higher employee severance costs in connection with the consolidation of some regional facilities, and decreased by \$9 million as the Utility incurred higher uncollectible expense driven by worsening economic conditions and increasing customer delinquency.

Key Factors Affecting Results of Operations and Financial Condition

PG&E Corporation's and the Utility's results of operations and financial condition depend primarily on whether the Utility is able to operate its business within authorized revenue requirements, recover its authorized costs timely, and earn its authorized rate of return. A number of factors have had, or are expected to have, a significant impact on PG&E Corporation's and the Utility's results of operations and financial condition, including:

- *The Outcome of Regulatory Proceedings and the Impact of Ratemaking Mechanisms* . Most of the Utility's revenue requirements are set based on its costs of service in proceedings such as the General Rate Case ("GRC") filed with the CPUC and transmission owner ("TO") rate cases filed with the FERC. On July 20, 2009 the Utility notified the CPUC of the Utility's intent to file its 2011-2013 GRC application by December 1, 2009 in which the Utility intends to request an increase in authorized electric distribution, gas distribution, and electric generation revenue requirements. (See "Regulatory Matters" below.) From time to time, the Utility also files separate applications requesting the CPUC or the FERC to authorize additional revenue requirements for specific capital expenditure projects, such as new power plants, gas or electric transmission facilities, installation of an advanced metering infrastructure, and reliability or system infrastructure improvements. The Utility's revenues will also be affected by incentive ratemaking, such as the CPUC's customer energy efficiency shareholder incentive mechanism. (See "Regulatory Matters" below.) In addition, the CPUC has authorized the Utility to recover 100% of its reasonable electric fuel and energy procurement costs and has established a timely rate adjustment mechanism to recover such costs. As a result, the Utility's revenues and costs can be affected by volatility in the prices of natural gas and electricity. (See "Risk Management Activities" below.)
- *Capital Structure and Return on Common Equity* . The Utility's current CPUC-authorized capital structure includes a 52% common equity component. The CPUC has authorized the Utility to set rates targeted to earn a ROE of 11.35% on the equity component of its electric and natural gas distribution and electric generation rate base. The Utility's capital structure is set until 2011, and its cost of capital components, including an 11.35% ROE, will be changed before 2011 only if the annual adjustment mechanism established by the CPUC is triggered. If the 12-month October-through-September average yield for the applicable Moody's Investors Service utility bond index increases or decreases by more than 1% as compared to the applicable benchmark, the Utility will file to adjust its authorized cost of capital effective on January 1 of the following year. The Utility can also apply for an adjustment to either its capital structure or its cost of capital at any time in the event of extraordinary circumstances.
- *The Ability of the Utility to Control Costs While Improving Operational Efficiency and Reliability* . The Utility's revenue requirements are generally set at a level to allow the Utility the opportunity to recover its basic forecasted operating expenses, as well as to earn an ROE and recover depreciation, tax, and interest expense associated with authorized capital expenditures. Differences in the amount or timing of forecasted and actual operating expenses and capital expenditures can affect the Utility's ability to earn its authorized rate of return and the amount of PG&E Corporation's income available for common shareholders. When capital expenditures are higher than authorized levels, the Utility incurs associated depreciation, property tax, and interest expense but does not recover revenues to fully offset these expenses or earn an ROE until the increased capital expenditures are added to rate base in future rate cases. Items that could cause higher expenses than provided for in the last GRC primarily relate to the Utility's efforts to maintain its aging electric and natural gas systems infrastructure; to improve the reliability and safety of its electric and natural gas system; and to improve its information technology infrastructure, support, and security. In addition, the Utility expects that it will continue to incur higher costs to accelerate system-wide natural gas leak surveys and associated remedial work. (See "Results of Operations" below.) The Utility continually seeks to achieve operational efficiencies and improve reliability while creating future sustainable cost savings to offset these higher anticipated expenses. The Utility also seeks to make the amount and timing of its capital expenditures consistent with budgeted amounts and timing.
- *The Availability and Terms of Debt and Equity Financing* . The amount and timing of the Utility's future financing needs will depend on various factors, including the conditions in the capital markets, the amount and timing of scheduled principal and interest payments on long-term debt, the amount and timing of planned capital expenditures, and the amount and timing of interest payments related to the remaining disputed claims that were made by electricity suppliers in the Utility's proceeding under Chapter 11 of the U.S. Bankruptcy Code ("Chapter 11"). (See Note 10 of the Notes to the Condensed Consolidated Financial Statements.) The amount of the Utility's short-term financing will vary depending on the level of operating cash flows, seasonal demand for electricity and natural gas, volatility in electricity and natural gas prices, and collateral requirements related to price risk management activity, among other factors. In order to maintain the Utility's CPUC-authorized capital structure, during 2009 PG&E Corporation contributed \$653 million of equity to the Utility. The timing and amount of future equity contributions will affect the timing and amount of any future equity or debt issuances by PG&E Corporation. In March 2009, PG&E Corporation and the Utility issued \$350 million and \$550 million, respectively, of senior unsecured notes. Additionally, the Utility issued \$500 million principal amount of Floating Rate Senior Notes due June 10, 2010. At June 30, 2009, the interest rate on the Floating Rate Senior Notes was 1.60%. (See "Liquidity and Financial Resources" below.)

FORWARD-LOOKING STATEMENTS

This combined quarterly report on Form 10-Q contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report. These forward-looking statements relate to, among other matters, estimated capital expenditures, estimated environmental remediation liabilities, estimated tax liabilities, the anticipated outcome of various regulatory and legal proceedings, estimated future cash flows, and the level of future equity or debt issuances, and are also identified by words such as "assume," "expect," "intend," "plan," "project," "believe," "estimate," "target," "predict," "anticipate," "aim," "may," "might," "should," "would," "could," "goal," "potential," and similar expressions. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

- the Utility's ability to manage capital expenditures and its operating and maintenance expenses within authorized levels;
- the outcome of pending and future regulatory proceedings and whether the Utility is able to timely recover its costs through rates;
- the adequacy and price of electricity and natural gas supplies, and the ability of the Utility to manage and respond to the volatility of the electricity and natural gas markets, including the ability of the Utility and its counterparties to post or return collateral;
- the effect of weather, storms, earthquakes, floods, disease, other natural disasters, explosions, fires, accidents, mechanical breakdowns, disruption of information technology and computer systems, acts of terrorism, and other events or hazards on the Utility's facilities and operations, its customers, and third parties on which the Utility relies;
- the potential impacts of climate change on the Utility's electricity and natural gas businesses;
- changes in customer demand for electricity and natural gas resulting from unanticipated population growth or decline, general economic and financial market conditions, changes in technology including the development of alternative energy sources, or other reasons;
- operating performance of the Utility's Diablo Canyon Power Plant ("Diablo Canyon"), the availability of nuclear fuel, the occurrence of unplanned outages at Diablo Canyon, or the temporary or permanent cessation of operations at Diablo Canyon;
- whether the Utility can maintain the cost savings that it has recognized from operating efficiencies that it has achieved and identify and successfully implement additional sustainable cost-saving measures;
- whether the Utility incurs substantial expense to improve the safety and reliability of its electric and natural gas systems;
- whether the Utility achieves the CPUC's energy efficiency targets and recognizes any incentives that the Utility may earn in a timely manner;
- the impact of changes in federal or state laws, or their interpretation, on energy policy and the regulation of utilities and their holding companies;
- the impact of changing wholesale electric or gas market rules, including the impact of future FERC-ordered changes that will be incorporated into the new day-ahead, hour-ahead, and real-time wholesale electricity markets established by the California Independent System Operator ("CAISO") to restructure the California wholesale electricity market;
- how the CPUC administers the conditions imposed on PG&E Corporation when it became the Utility's holding company;
- the extent to which PG&E Corporation or the Utility incurs costs and liabilities in connection with litigation that are not recoverable through rates, from insurance, or from other third parties;

- the ability of PG&E Corporation, the Utility, and counterparties to access capital markets and other sources of credit in a timely manner on acceptable terms;
- the impact of environmental laws and regulations and the costs of compliance and remediation;
- the effect of municipalization, direct access, community choice aggregation, or other forms of bypass; and
- the outcome of federal or state tax audits and the impact of changes in federal or state tax laws, policies, or regulations.

For more information about the significant risks that could affect the outcome of these forward-looking statements and PG&E Corporation's and the Utility's future financial condition and results of operations, see the discussion in the section entitled "Risk Factors" in the 2008 Annual Report and the discussion below under Part II. Other Information, Item 1A. Risk Factors. 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 six months ended June 30, 2009 and 2008:

(in millions)	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Utility				
Electric operating revenues	\$ 2,554	\$ 2,645	\$ 4,980	\$ 5,159
Natural gas operating revenues	640	933	1,645	2,152
Total operating revenues	3,194	3,578	6,625	7,311
Cost of electricity	883	1,097	1,766	2,124
Cost of natural gas	188	487	745	1,262
Operating and maintenance	1,037	991	2,096	2,027
Depreciation, amortization, and decommissioning	429	418	848	820
Total operating expenses	2,537	2,993	5,455	6,233
Operating Income	657	585	1,170	1,078
Interest income	17	33	26	57
Interest expense	(166)	(178)	(339)	(358)
Other income, net	15	7	36	26
Income Before Income Taxes	523	447	893	803
Income tax provision	132	134	263	254
Net Income	391	313	630	549
Preferred stock dividend requirement	4	4	7	7
Income Available for Common Stock	\$ 387	\$ 309	\$ 623	\$ 542
PG&E Corporation, Eliminations, and Other ⁽¹⁾				
Operating revenues	\$ -	\$ -	\$ -	\$ -
Operating expenses	1	1	1	1
Operating Loss	(1)	(1)	(1)	(1)
Interest income	-	-	-	2
Interest expense	(12)	(7)	(20)	(14)
Other income (expense), net	7	(2)	4	(16)
Loss Before Income Taxes	(6)	(10)	(17)	(29)
Income tax provision (benefit)	(7)	6	(23)	(4)
Net Income (Loss)	\$ 1	\$ (16)	\$ 6	\$ (25)
Consolidated Total				
Operating revenues	\$ 3,194	\$ 3,578	\$ 6,625	\$ 7,311
Operating expenses	2,538	2,994	5,456	6,234
Operating Income	656	584	1,169	1,077
Interest income	17	33	26	59
Interest expense	(178)	(185)	(359)	(372)
Other income, net	22	5	40	10
Income Before Income Taxes	517	437	876	774
Income tax provision	125	140	240	250
Net Income	392	297	636	524
Preferred stock dividend requirement of subsidiary	4	4	7	7
Income Available for Common Shareholders	\$ 388	\$ 293	\$ 629	\$ 517

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

Utility

The following presents the Utility's operating results for the three and six months ended June 30, 2009 and 2008.

Electric Operating Revenues

The Utility provides electricity to residential, industrial, agricultural, and small and large commercial customers through its own generation facilities and through power purchase agreements with third parties. In addition, the Utility relies on electricity provided under long-term contracts entered into by the California Department of Water Resources ("DWR") to meet a material portion of the Utility's customers' demand ("load"). The Utility's electric operating revenues consist of amounts charged to customers for electricity generation and procurement and for electric transmission and distribution services, as well as amounts charged to customers to recover the cost of public purpose programs, energy efficiency programs, and demand side management.

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

(in millions)	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Electric revenues	\$ 3,012	\$ 2,948	\$ 5,833	\$ 5,789
DWR pass-through revenues ⁽¹⁾	(458)	(303)	(853)	(630)
Total electric operating revenues	\$ 2,554	\$ 2,645	\$ 4,980	\$ 5,159

⁽¹⁾ These are revenues collected on behalf of the DWR for electricity allocated to the Utility's customers under contracts between the DWR and power suppliers, and are not included in the Utility's Condensed Consolidated Statements of Income.

The Utility's total electric operating revenues decreased by \$91 million, or 3%, in the three months ended June 30, 2009 and \$179 million, or 3%, in the six months ended June 30, 2009, compared to the same period in 2008, mainly due to the following factors:

- Electricity procurement costs passed through to customers decreased by \$238 million in the three months ended June 30, 2009 and \$385 million in the six months ended June 30, 2009. (See "Cost of Electricity" below.)
- Public purpose program costs passed through to customers decreased by \$17 million in the three months ended June 30, 2009 and \$46 million in the six months ended June 30, 2009, due to timing of program spending. (See "Operating and Maintenance" below.)
- Other miscellaneous decreases in electric operating revenues of \$2 million in the three months ended June 30, 2009 and \$6 million in the six months ended June 30, 2009.

These decreases were partially offset by the following:

- Base revenues increased by \$26 million in the three months ended June 30, 2009 and \$52 million in the six months ended June 30, 2009, as a result of attrition adjustments as authorized in the 2007 GRC.
- Revenues associated with separately funded projects placed in service, including the Gateway Generating Station and the new steam generators at Diablo Canyon, increased by \$47 million in the three months ended June 30, 2009 and \$94 million in the six months ended June 30, 2009.
- Electric operating revenues increased by \$35 million in the three and six months ended June 30, 2009 for the recovery of costs related to hydroelectric generation facilities in 2000 and 2001. (See "Regulatory Matters" below.)

- Electric transmission revenues increased by \$38 million in the three months ended June 30, 2009 and \$57 million in the six months ended June 30, 2009, primarily due to an increase in rates as authorized in the current TO rate case.
- Electric operating revenues increased by \$20 million in the three and six months ended June 30, 2009 due to recovery of collateral payments to the CAISO in order to participate in the new day-ahead market. (See “Operating and Maintenance” below.)

The Utility’s electric operating revenues for the remainder of 2009 and 2010 are expected to increase as authorized by the CPUC in the 2007 GRC. The Utility’s electric operating revenues for future years are also expected to increase as authorized by the FERC in the TO rate cases. (See “Regulatory Matters” below.)

In addition, the Utility expects to continue to collect revenue requirements related to CPUC-approved capital expenditures outside the GRC, including capital expenditures for the new Utility-owned generation projects and the SmartMeter™ advanced metering project. Revenues would also increase to the extent that the CPUC approves the Utility’s proposal for other capital projects. (See “Capital Expenditures” below.)

Revenue requirements associated with new or expanded public purpose, energy efficiency, and demand response programs will also result in increased electric operating revenues. In addition, future electric operating revenues are affected by changes in the Utility’s electricity procurement costs as discussed under “Cost of Electricity” below. Finally, the Utility may recognize additional incentive revenues to the extent that it achieves the CPUC’s energy efficiency goals.

Cost of Electricity

The Utility’s cost of electricity includes purchase power costs, the cost of fuel used in its generation facilities, and the cost of fuel supplied to other facilities under tolling agreements. These costs are passed through to customers. The Utility’s cost of electricity also includes realized gains and losses on price risk management activities. (See Notes 7 and 8 of the Notes to the Condensed Consolidated Financial Statements.) The Utility’s cost of electricity excludes non-fuel costs associated with the Utility’s own generation facilities, which are included in Operating and maintenance expense in the Condensed Consolidated Statements of Income. The cost of electricity provided under power purchase agreements between the DWR and various power suppliers is also excluded from the Utility’s cost of electricity.

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

(in millions)	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Cost of purchased power	\$ 852	\$ 1,140	\$ 1,721	\$ 2,178
Proceeds from surplus sales allocated to the Utility	(17)	(90)	(48)	(135)
Fuel used in own generation	48	47	93	81
Total cost of electricity	\$ 883	\$ 1,097	\$ 1,766	\$ 2,124
Average cost of purchased power per kWh ⁽¹⁾	\$ 0.084	\$ 0.089	\$ 0.081	\$ 0.088
Total purchased power (in millions of kWh)	10,177	12,862	21,165	24,652

⁽¹⁾ Kilowatt-hour

The Utility’s total cost of electricity decreased by \$214 million, or 20%, in the three months ended June 30, 2009 and by \$358 million, or 17%, in the six months ended June 30, 2009, compared to the same periods in 2008. This was primarily due to a decrease in the average cost of purchased power of 6% for the three months ended June 30, 2009 and 8% for the six months ended June 30, 2009, as well as a decrease in the total volume of purchased power of 21% for the three months ended June 30, 2009 and 14% for the six months ended June 30, 2009. The decrease in the average cost of purchased power was primarily driven by lower market prices for electricity and gas. The decrease in the volume of purchased power was due to a reduction in industrial and residential demand as the economic downturn continued and milder weather, as compared to the same period in 2008. These decreases were partially offset by a reduction in proceeds from surplus sales of 81% in the three months ended June 30, 2009 and 64% in the six months ended June 30, 2009, primarily due to decreases in spot and day-ahead market prices for electricity and gas.

Various factors will affect the Utility’s future cost of electricity including the market prices for electricity and natural gas, the level of hydroelectric and nuclear power that the Utility produces, the cost of procuring more renewable energy, changes in customer demand, and the amount and timing of power purchases needed to replace power previously supplied under the DWR contracts as those contracts expire or are terminated, novated, or renegotiated. In addition, the output from the Utility’s hydroelectric generation facilities is dependent on levels of precipitation and could impact the volume of purchased power.

The Utility’s future cost of electricity also may be affected by federal or state legislation or rules that may be adopted to regulate the emissions of greenhouse gases from the Utility’s electricity generating facilities or the generating facilities from which the Utility procures electricity. In particular, costs are likely to increase in the future when California’s statewide greenhouse gas emissions reduction law is implemented.

Natural Gas Operating Revenues

The Utility sells natural gas and natural gas transportation services. The Utility's transportation services are provided by a transmission system and a distribution system. The transmission system transports gas throughout its service territory for delivery to the Utility's distribution system, which, in turn, delivers natural gas to end-use customers. The transmission system also delivers natural gas to large end-use customers who are connected directly to the transmission system. In addition, the Utility delivers natural gas to off-system markets, primarily in southern California.

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

(in millions)	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Bundled natural gas revenues	\$ 555	\$ 849	\$ 1,478	\$ 1,990
Transportation service-only revenues	85	84	167	162
Total natural gas operating revenues	\$ 640	\$ 933	\$ 1,645	\$ 2,152
Average bundled revenue per Mcf ⁽¹⁾ of natural gas sold	\$ 10.67	\$ 15.72	\$ 9.66	\$ 11.92
Total bundled natural gas sales (in millions of Mcf)	52	54	153	167

⁽¹⁾ One thousand cubic feet

The Utility's total natural gas operating revenues decreased by \$293 million, or 31%, in the three months ended June 30, 2009 and by \$507 million, or 24%, in the six months ended June 30, 2009, compared to the same periods in 2008. These decreases were primarily due to a decrease in the total cost of natural gas of \$299 million in the three months ended June 30, 2009 and \$517 million in the six months ended June 30, 2009. (See "Cost of Natural Gas" below.) Additionally, other natural gas operating revenues decreased by \$2 million in the three months ended June 30, 2009 and \$6 million in the six months ended June 30, 2009. These decreases were partially offset by increased base revenue requirements as a result of attrition adjustments as authorized in the 2007 GRC and increased revenues as authorized in the 2008 Gas Accord of \$8 million and \$16 million in the three and six months ended June 30, 2009, respectively.

Future natural gas operating revenues will be affected by changes in the cost of natural gas, the Utility's gas transportation rates, natural gas throughput volume, and other factors. For 2008 through 2010, the Gas Accord IV settlement agreement provides for an increase in the revenue requirements and rates for the Utility's gas transmission and storage services. In addition, the Utility's natural gas operating revenues for distribution are expected to increase through 2010 as a result of revenue requirement increases authorized by the CPUC in the 2007 GRC. Finally, the Utility may recognize incentive revenues to the extent that it achieves the CPUC's energy efficiency goals.

Cost of Natural Gas

The Utility's cost of natural gas includes the purchase costs of natural gas and transportation costs on interstate pipelines and intrastate pipelines, but excludes the transportation costs for non-core customers, which are included in Operating and maintenance expense in the Condensed Consolidated Statements of Income. The Utility's cost of natural gas also includes realized gains and losses on price risk management activities. (See Notes 7 and 8 of the Notes to the Condensed Consolidated Financial Statements.)

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

(in millions)	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Cost of natural gas sold	\$ 149	\$ 448	\$ 664	\$ 1,202
Transportation cost of natural gas sold	39	39	81	60
Total cost of natural gas	\$ 188	\$ 487	\$ 745	\$ 1,262
Average cost per Mcf of natural gas sold	\$ 2.87	\$ 8.30	\$ 4.34	\$ 7.20
Total natural gas sold (in millions of Mcf)	52	54	153	167

The Utility's total cost of natural gas decreased in the three and six months ended June 30, 2009 by \$299 million, or 61%, and by \$517 million, or 41%, respectively, compared to the same periods in 2008, primarily due to decreases in the 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 cost of gas may be affected by federal or state legislation or rules to regulate the emissions of greenhouse gases 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 accounts and service expenses, public purpose program expenses, and administrative and general expenses.

The Utility's operating and maintenance expenses increased by \$46 million, or 5%, in the three months ended June 30, 2009 compared to the same period in 2008. Operating and maintenance expenses increased due to a \$10 million increase in wage and benefit-related costs, increased labor and other costs of \$18 million related to accelerated natural gas leak surveys and associated remedial work, and a \$2 million increase in uncollectible customer accounts as a result of economic conditions and rising unemployment in the Utility's service territory. Additionally, operating and maintenance expenses increased by \$13 million due to increases in environmental compliance costs, and a \$20 million increase related to collateral payments to the CAISO (passed through to customers) in order to participate in the new day-ahead market. These increases were partially offset by decreases in public purpose program expenses of \$13 million, and a \$4 million decrease in other miscellaneous operating and maintenance expenses.

The Utility's operating and maintenance expenses increased by \$69 million, or 3%, in the six months ended June 30, 2009 compared to the same period in 2008. Operating and maintenance expenses increased due to a \$47 million increase in wage and benefit-related costs, a \$20 million increase in uncollectible customer accounts as a result of economic conditions and rising unemployment in the Utility's service territory, severance costs of \$10 million incurred in connection with the consolidation of some regional facilities, increased labor and other costs of \$27 million related to accelerated natural gas leak surveys and associated remedial work, and a \$20 million increase related to collateral payments to the CAISO (passed through to customers) in order to participate in the new day-ahead market. Additionally, operating and maintenance expenses increased by \$13 million due to increases in environmental compliance costs, and \$21 million due to other miscellaneous operating and maintenance expenses. These increases were partially offset by decreases in public purpose program expenses of \$51 million, and decreases in labor costs of \$38 million compared to those incurred in 2008 as a result of the January 2008 winter storm.

Operating and maintenance expenses are influenced by wage inflation; benefits; property taxes; the timing and length of Diablo Canyon refueling outages; storms, wild fires, and other events causing outages and damages in the Utility's service territory; environmental remediation costs; legal costs; material costs; and various other administrative and general expenses. The Utility anticipates that it will incur higher costs in the future to operate and maintain its aging infrastructure and to improve operating and maintenance processes used in its natural gas system. (See "Risk Factors" in the 2008 Annual Report.) In particular, the Utility has begun work associated with system-wide natural gas leak surveys and targets completing the accelerated portion of this survey work by the second quarter of 2010. The Utility forecasts that it will spend approximately \$100 million in 2009 to perform the accelerated natural gas leak surveys and associated remedial work. The Utility also expects that it will incur higher expenses in future periods to obtain permits or comply with permitting requirements, including costs associated with renewed FERC licenses for the Utility's hydroelectric generation facilities. To help offset these increased costs, the Utility intends to continue its efforts to identify and implement initiatives to achieve operational efficiencies and to create future sustainable cost savings.

Depreciation, Amortization, and Decommissioning

The Utility's depreciation, amortization, and decommissioning expenses increased by \$11 million, or 3%, in the three months ended June 30, 2009 and \$28 million, or 3%, in the six months ended June 30, 2009, as compared to the same periods in 2008. Depreciation expense increased by \$30 million and \$56 million in the three and six months ended June 30, 2009, respectively. The increases are primarily due to capital additions and depreciation rate changes as authorized in the TO10 rate case. These increases were partially offset by decreases in decommissioning expense and amortization expense related to the energy recovery bonds ("ERBs") of \$19 million in the three months ended June 30, 2009 and \$28 million in the six months ended June 30, 2009.

The Utility's depreciation, amortization, and decommissioning expenses for the remainder of 2009 and 2010 are expected to increase as a result of an overall increase in capital expenditures and implementation of depreciation rates authorized by the 2007 GRC decision. Depreciation, amortization, and decommissioning expenses in subsequent years will be determined based on rates set in the 2011 GRC and future TO rate cases.

Interest Income

In the three and six months ended June 30, 2009, the Utility's interest income decreased by \$16 million, or 48%, and \$31 million, or 54%, respectively, as compared to the same periods in 2008 primarily due to lower interest rates earned on restricted cash held related to Chapter 11 disputed claims and a decrease in interest income associated with certain balancing accounts. (See Note 10 of the Notes to the Condensed Consolidated Financial Statements.) These decreases were partially offset by an increase of \$12 million in the three and six months ended June 30, 2009 for the recovery of interest on costs related to the hydroelectric generation facilities in 2000 and 2001. (See "Regulatory Matters" below.)

The Utility's interest income in 2009 and future periods will be primarily affected by changes in the balance held in escrow related to disputed claims and changes in interest rate levels.

Interest Expense

In the three and six months ended June 30, 2009, there was a decrease in interest expense of \$12 million, or 7%, and \$19 million, or 5%, respectively, as compared to the same period in 2008. Interest expense decreased primarily due to the following factors:

- Interest expense decreased by \$14 million in the three months ended June 30, 2009, and \$28 million in the six months ended June 30, 2009, primarily due to lower FERC interest rates accrued on the liability for disputed claims.
- Interest expense decreased by \$10 million in the three months ended June 30, 2009, and \$17 million in the six months ended June 30, 2009, primarily due to lower interest rates affecting various balancing accounts.
- Interest expense decreased by \$4 million in the three months ended June 30, 2009, and \$10 million in the six months ended June 30, 2009, due to the reduction of the outstanding balance of ERBs.
- Interest expense on pollution control bonds decreased by \$8 million in the six months ended June 30, 2009, due to the repurchase of auction rate pollution control bonds in March and April 2008. The Utility partially refunded these bonds in September and October 2008. Additionally, interest expense decreased due to lower interest rates on outstanding variable rate pollution control bonds.
- Interest expense decreased by \$10 million in the three months ended June 30, 2009, and \$11 million in the six months ended June 30, 2009, primarily due to decreases in other interest expense.

These decreases were partially offset by additional interest expense of \$26 million in the three months ended June 30, 2009, and \$55 million in the six months ended June 30, 2009, primarily related to \$2.4 billion in senior notes that were issued in 2008 and March 2009.

The Utility's interest expense in 2009 and future periods will be impacted by changes in interest rates, as well as by changes in the amount of debt outstanding as long-term debt matures and additional long-term debt is issued. (See "Liquidity and Financial Resources" below.)

Income Tax Expense

The Utility's income tax expense decreased by \$2 million, or 1%, for the three months ended June 30, 2009 and increased by \$9 million, or 4%, for the six months ended June 30, 2009, as compared to the same period in 2008. The effective tax rates for the three months ended June 30, 2009 and 2008 were 25.3% and 30.0%, respectively. The effective tax rates for the six months ended June 30, 2009 and 2008 were 29.6% and 31.6%, respectively. The lower effective tax rate in 2009 was due primarily to a favorable Internal Revenue Service ("IRS") audit settlement included in the three and six months ended June 30, 2009, in excess of a favorable IRS settlement received in the comparable periods in 2008. (See Note 11 of the Notes to the Condensed Consolidated Financial Statements for a discussion of "Tax Matters.")

PG&E Corporation, Eliminations, and Other

Operating Revenues and Expenses

PG&E Corporation's revenues consist mainly of billings to its affiliates for services rendered, all of which are eliminated in consolidation. PG&E Corporation's operating expenses consist mainly of employee compensation and payments to third parties for goods and services. Generally, PG&E Corporation's operating expenses are allocated to affiliates. These allocations are made without mark-up and are eliminated in consolidation. PG&E Corporation's interest expense relates to its 9.50% Convertible Subordinated Notes and 5.75% Senior Notes, and is not allocated to affiliates.

There were no material changes to PG&E Corporation's operating income in the three and six months ended June 30, 2009, as compared to the same period in 2008.

LIQUIDITY AND FINANCIAL RESOURCES

Overview

The Utility's ability to fund operations depends on the levels of its operating cash flow and access to the capital markets. The levels of the Utility's operating cash and short-term debt fluctuate as a result of seasonal demand for electricity and natural gas, volatility in energy commodity costs, collateral requirements related to price risk management activity, the timing and amount of tax payments or refunds, and the timing and effect of regulatory decisions and financings, among other factors. The Utility generally utilizes long-term senior unsecured debt issuances and equity contributions from PG&E Corporation to fund debt maturities and capital expenditures and to maintain its CPUC-authorized capital structure. The Utility relies on short-term debt, including commercial paper, to fund temporary financing needs. On May 7, 2009, the CPUC increased the Utility's short-term borrowing authority by \$1.5 billion, for an aggregate authority of \$4.0 billion, including \$500 million that is restricted to certain contingencies.

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

Credit Facilities

At December 31, 2008, PG&E Corporation had a \$200 million revolving credit facility and the Utility had a \$2.0 billion revolving credit facility. Commitments from Lehman Brothers Bank, FSB (“Lehman Bank”) represented \$13 million, or 7%, and \$60 million, or 3%, of the total borrowing capacity under PG&E Corporation’s and the Utility’s revolving credit facilities, respectively. On April 27, 2009, PG&E Corporation and the Utility amended their revolving credit facilities and removed Lehman Bank as a lender. As a result, PG&E Corporation now has a \$187 million revolving credit facility, and the Utility has a \$1.94 billion revolving credit facility. The Utility’s revolving credit facility also provides liquidity support for commercial paper issued under the Utility’s \$1.75 billion commercial paper program.

The following table summarizes PG&E Corporation's and the Utility's outstanding commercial paper and credit facilities at June 30, 2009:

(in millions)

			At June 30, 2009				
Authorized Borrower	Facility	Termination Date	Facility Limit	Letters of Credit Outstanding	Cash Borrowings	Commercial Paper Backup	Availability
PG&E Corporation	Revolving credit facility	February 2012	\$ 187 ⁽¹⁾	\$ -	\$ -	\$ -	\$ 187
Utility	Revolving credit facility	February 2012	1,940 ⁽²⁾	303	-	243	1,394
Total credit facilities			\$ 2,127	\$ 303	\$ -	\$ 243	\$ 1,581

⁽¹⁾ Includes an \$87 million sublimit for letters of credit and \$100 million sublimit for "swingline" loans, defined as loans that are made available on a same-day basis and are repayable in full within 30 days.

⁽²⁾ Includes a \$921 million sublimit for letters of credit and \$200 million sublimit for swingline loans.

PG&E Corporation's and the Utility's revolving credit facilities include usual and customary covenants for credit facilities of their type, including covenants limiting liens to those permitted under the senior notes' indenture, mergers, sales of all or substantially all of the Utility's assets, and other fundamental changes. In addition, both PG&E Corporation and the Utility are required to maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65%, and PG&E Corporation must own, directly or indirectly, at least 80% of the common stock and at least 70% of the voting securities of the Utility. At June 30, 2009, PG&E Corporation and the Utility were in compliance with all covenants.

2009 Financings

In March 2009, PG&E Corporation and the Utility issued \$350 million and \$550 million, respectively, of senior unsecured notes. Proceeds from the senior notes offerings were used to finance capital expenditures and general working capital and to repay outstanding commercial paper, which the Utility had issued to pay off \$600 million of senior unsecured notes that matured on March 1, 2009. On June 11, 2009, the Utility issued \$500 million of floating rate senior unsecured notes due June 10, 2010. The net proceeds were used to pay down outstanding commercial paper that was issued to satisfy margin calls and collateral requirements related to the Utility's electric procurement commodity hedging activities.

In addition, PG&E Corporation issued 7,202,448 shares of common stock upon exercise of employee stock options and under its 401 (k) plan and Dividend Reinvestment and Stock Purchase Plan ("DRSPP"), generating \$182 million of cash through June 30, 2009. Also in 2009, PG&E Corporation contributed \$653 million of cash to the Utility to ensure that the Utility had adequate capital to fund its capital expenditures and to maintain the 52% common equity ratio authorized by the CPUC.

Future Financing Needs

The amount and timing of the Utility's future financing needs will depend on various factors, including the conditions in the capital markets and the Utility's ability to access the capital markets, the timing and amount of forecasted capital expenditures, and the amount of cash internally generated through normal business operations, among other factors. The Utility's future financing needs will also depend on 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 10 of the Notes to the Condensed Consolidated Financial Statements.)

Assuming that PG&E Corporation and the Utility can access the capital markets on reasonable terms, PG&E Corporation and the Utility believe that the Utility's cash flow from operations, existing sources of liquidity, and future financings will provide adequate resources to fund operating activities, meet anticipated obligations, and finance future capital expenditures.

Dividends

During the six months ended June 30, 2009, the Utility paid common stock dividends totaling \$312 million to PG&E Corporation.

During the six months ended June 30, 2009, PG&E Corporation paid common stock dividends totaling \$286 million, net of \$11 million that was reinvested in additional shares of common stock by participants in DRSPP. On June 17, 2009, the Board of Directors of PG&E Corporation declared a dividend of \$0.42 per share, totaling \$155 million, which was paid on July 15, 2009 to shareholders of record on June 30, 2009.

During the six months ended June 30, 2009, the Utility paid cash dividends totaling \$7 million to holders of its outstanding series of preferred stock. On June 17, 2009, the Board of Directors of the Utility declared a cash dividend totaling \$3 million on its outstanding series of preferred stock, payable on August 15, 2009 to shareholders of record on July 31, 2009.

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 six months ended June 30, 2009 and 2008 were as follows:

(in millions)	Six Months Ended June 30,	
	2009	2008
Net income	\$ 630	\$ 549
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	932	902
Allowance for equity funds used during construction	(47)	(32)
Deferred income taxes and tax credits, net	368	316
Other changes in noncurrent assets and liabilities	(34)	480
Effect of changes in operating assets and liabilities:		
Accounts receivable	199	(66)
Inventories	113	(57)
Accounts payable	(140)	123
Income taxes receivable/payable	64	57
Regulatory balancing accounts, net	(228)	(351)
Other current assets	10	429
Other current liabilities	(220)	(73)
Other	3	(3)
Net cash provided by operating activities	\$ 1,650	\$ 2,274

In the six months ended June 30, 2009, net cash provided by operating activities decreased \$624 million compared to the same period in 2008. This decrease was primarily due to an increase in net collateral paid of \$944 million. The increase in net collateral paid, which is primarily related to price risk management activities, was a result of changes in the Utility's exposure to counterparties' credit risk, generally reflecting declining natural gas prices. Collateral payables and receivables are included in Other changes in noncurrent assets and liabilities, Other current assets, and Other current liabilities in the table above. This cash outflow was partially offset by net tax refunds of \$70 million related to the Utility's portion of the settlement of the IRS audits of PG&E Corporation's consolidated tax returns for tax years 2001 through 2004. The remaining offset to the net collateral paid consisted of miscellaneous other changes in operating assets and liabilities due to timing differences and seasonality.

Future operating cash flows will be impacted by the timing of cash collateral payments and receipts related to price risk management activity, among other factors. The Utility's cash collateral activity will fluctuate based on changes in the Utility's net credit exposure, which is primarily dependent on electricity and gas price movement. The Utility's operating cash flows also will be impacted by electricity procurement costs and the timing of rate adjustments authorized to recover these costs.

On June 8, 2009, the IRS executed a closing agreement to resolve refund claims related to the 1998 and 1999 tax years after the U.S. Congress' Joint Committee on Taxation indicated that it took no exception to the settlement. The refund of tax and interest from the IRS as a result of the settlement is approximately \$310 million. In July 2009, PG&E Corporation and the Utility received the majority of this refund from the IRS. The remaining amount is expected in the third quarter of 2009. (See Note 11 of the Notes to the Condensed Consolidated Financial Statements for a discussion of "Tax Matters.") Additionally, the extension by the American Recovery and Reinvestment Act of 2009 of "bonus depreciation" for an additional year is expected to have a positive impact on operating cash flows in 2009 and 2010.

In addition, the Utility's future operating cash flows may also be impacted by the amount and timing of funding obligations associated with nuclear decommissioning and employee benefits. As a result of lower assumed rates of return and declining investment returns on investments set aside to satisfy the obligations, the Utility's obligations to fund decommissioning of its nuclear generation facilities and to secure payment of employee benefits under pension and other postretirement benefit plans may increase. The Utility believes that it is probable that any increase in these obligations would be recoverable through rates. (See "Regulatory Matters" below.)

Investing Activities

The Utility's investing activities consist of construction of new and replacement facilities necessary to deliver safe and reliable electricity and natural gas services to its customers. Cash used in investing activities depends primarily upon the amount and type of construction activities, which can be influenced by the need to make electricity and natural gas reliability improvements as well as by storms and other factors.

The Utility's cash flows from investing activities for the six months ended June 30, 2009 and 2008 were as follows:

(in millions)	Six Months Ended June 30,	
	2009	2008
Capital expenditures	\$ (2,077)	\$ (1,712)
Proceeds from sale of assets	5	12
Decrease (increase) in restricted cash	15	(7)
Proceeds from nuclear decommissioning trust sales	954	636
Purchases of nuclear decommissioning trust investments	(985)	(665)
Net cash used in investing activities	\$ (2,088)	\$ (1,736)

Net cash used in investing activities increased by \$352 million in the six months ended June 30, 2009 compared to the same period in 2008. This increase was primarily due to an increase of \$365 million in capital expenditures for installing the SmartMeter™ advanced metering infrastructure, generation facility spending, replacing and expanding gas and electric distribution systems, and improving the electric transmission infrastructure. (See "Capital Expenditures" below.)

Future cash flows used in investing activities are largely dependent on expected capital expenditures. (See "Capital Expenditures" below and in the 2008 Annual Report.)

Financing Activities

The Utility's cash flows from financing activities for the six months ended June 30, 2009 and 2008 were as follows:

(in millions)	Six Months Ended June 30,	
	2009	2008
Net repayments under revolving credit facility	\$ -	\$ (250)
Net repayments of commercial paper, net of discount of \$3 million in 2009 and \$2 million in 2008	(47)	(114)
Proceeds from issuance of short-term debt, net of issuance costs of \$1 million in 2009	499	-
Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of \$12 million in 2009 and \$2 million in 2008	538	598
Long-term debt matured or repurchased	(600)	(454)
Energy recovery bonds matured	(174)	(165)
Preferred stock dividends paid	(7)	(7)
Common stock dividends paid	(312)	(284)
Equity contribution	653	50
Other	(6)	16
Net cash provided by (used in) financing activities	\$ 544	\$ (610)

In the six months ended June 30, 2009, net cash provided by financing activities increased by \$1,154 million compared to the same period in 2008. Cash provided by or used in financing activities is driven by the Utility's financing needs, which depend on the level of cash provided by or used in operating activities and the level of cash provided by or used in investing activities. The Utility generally utilizes long-term senior unsecured debt issuances and equity contributions from PG&E Corporation to fund debt maturities and capital expenditures and to maintain its CPUC-authorized capital structure and relies on short-term debt to fund temporary financing needs.

PG&E Corporation

With the exception of dividend payments, interest, common stock issuance, the senior notes issuance of \$350 million in March 2009, tax refunds of \$131 million, and transactions between PG&E Corporation and the Utility, PG&E Corporation had no material cash flows on a stand-alone basis for the six months ended June 30, 2009 and 2008.

CONTRACTUAL COMMITMENTS

PG&E Corporation and the Utility enter into contractual commitments in connection with business activities. These future obligations primarily relate to financing arrangements (such as long-term debt, preferred stock, and certain forms of regulatory financing), purchases of transportation capacity, natural gas and electricity to support customer demand, and the purchase of fuel and transportation to support the Utility's generation activities. In addition to those commitments disclosed in the 2008 Annual Report and those arising from normal business

activities, PG&E Corporation's and the Utility's commitments at June 30, 2009 include \$350 million of 5.75% Senior Notes issued by PG&E Corporation due April 1, 2014, \$550 million of 6.25% Senior Notes issued by the Utility due March 1, 2039, and \$500 million of Floating Rate Senior Notes issued by the Utility due June 10, 2010. (See the 2008 Annual Report and Notes 4, 5, 10, and 11 of the Notes to the Condensed Consolidated Financial Statements.)

CAPITAL EXPENDITURES

Depending on conditions in the capital markets, the Utility forecasts that it will make various capital investments in its electric and gas transmission and distribution infrastructure to maintain and improve system reliability, safety, and customer service; to extend the life of or replace existing infrastructure; and to add new infrastructure to meet already authorized growth. Most of the Utility's revenue requirements to recover forecasted capital expenditures are authorized in the GRC and TO rate cases. The Utility plans to file a GRC application with the CPUC by December 1, 2009 to request an increase in authorized revenue requirements to recover capital expenditures forecast to be made in 2011 through 2013. (See "Regulatory Matters" below.) In addition, from time to time, the Utility requests authorization to collect additional revenue requirements to recover capital expenditures related to specific projects such as new power plants, gas or electric transmission projects, and the SmartMeter™ advanced metering infrastructure.

Proposed Electric Distribution Reliability Program (Cornerstone Improvement Program)

On February 23, 2009, a ruling was issued that establishes a schedule for the CPUC's consideration of the Utility's request for approval of a proposed six-year electric distribution reliability improvement program. Hearings have been scheduled to begin in August 2009, and a final decision is scheduled to be issued in January 2010. On March 17, 2009, the Utility filed revised forecasts of proposed capital expenditures totaling \$2.0 billion, a decrease from the original forecast of \$2.3 billion, and proposed operating and maintenance expenses totaling \$59 million, a slight increase from the original forecast of \$43 million, over the six-year period of 2010 through 2016.

SmartMeter™ Program

Since late 2006, the Utility has been installing an advanced metering infrastructure, known as the SmartMeter™ program, for virtually all of the Utility's electric and gas customers. This infrastructure results in substantial cost savings associated with billing customers for energy usage, and enables the Utility to measure usage of electricity on a time-of-use basis and to charge time-differentiated rates. The main goal of time-differentiated rates is to encourage customers to reduce energy consumption during peak demand periods and to reduce procurement costs. Advanced meters can record usage in time intervals and be read remotely. The Utility expects to complete the majority of the installation throughout its service territory by the end of 2011.

The CPUC authorized the Utility to recover the \$1.74 billion estimated SmartMeter™ project cost, including an estimated capital cost of \$1.4 billion. The \$1.74 billion amount includes \$1.68 billion for project costs and \$54.8 million for costs to market critical peak pricing programs primarily for residential customers, SmartRate, that are made possible by SmartMeter™ technology. In addition, the Utility can recover in rates 90% of up to \$100 million in costs that exceed \$1.68 billion without a reasonableness review by the CPUC. The remaining 10% will not be recoverable in rates. If additional costs exceed the \$100 million threshold, the Utility may request recovery of the additional costs, subject to a reasonableness review. Through June 30, 2009, the Utility has spent an aggregate of \$1.01 billion, including capital costs of \$854 million, to install the SmartMeter™ system.

On March 12, 2009, the CPUC authorized the Utility to upgrade elements of its SmartMeter™ advanced metering infrastructure project. The CPUC authorized additional funding of \$466.8 million, including \$402 million of capital costs, to be recovered through an increased revenue requirement. The Utility intends to install upgraded electric meters with associated devices that would offer an expanded range of service features for electric customers that would support energy conservation and demand response options, such as the ability to present near-real-time energy consumption data to customers so that they could use energy more wisely in response to near-real-time energy data. These upgraded meters would also increase operational efficiencies for the Utility through, among other things, the ability to remotely connect and disconnect service to electric customers. In addition, the upgraded electric meters are designed to facilitate the Utility's ability to incorporate future advanced metering technology innovations in a timely and cost-effective manner.

The Utility's ability to recognize the expected benefits of its SmartMeter™ advanced metering infrastructure remains subject to a number of risks, including whether the Utility incurs additional advanced metering project costs that the CPUC does not find reasonable or that are not recoverable in rates, whether the project is implemented on schedule, whether the Utility can successfully integrate the new advanced metering system with its billing and other computer information systems, and whether the new technology performs as intended.

Diablo Canyon Steam Generator Replacement Project

In November 2005, the CPUC authorized the Utility to replace the steam generators at the two nuclear operating units at Diablo Canyon (Units 1 and 2) and recover costs of up to \$706 million from customers without further reasonableness review. The Utility installed four of the new steam generators in Unit 2 during 2008 and completed installation of the remaining new generators for Unit 1 on March 7, 2009. As of June 30, 2009, the Utility has incurred costs of \$685 million. If costs exceed the authorized threshold, the CPUC authorized the Utility to recover costs of up to \$815 million, subject to reasonableness review of the full amount.

Proposed New Generation Facilities

Proposed Renewable Energy Development

In its February 24, 2009 application, the Utility has requested that the CPUC approve the Utility's proposed development and construction of up to 250 megawatt of Utility-owned generating facilities using solar photovoltaic technology, to be deployed over a period of five years, to help the Utility meet its obligation under California law to increase the amount of electricity provided to customers from renewable generation resources. On July 1, 2009, the CPUC issued a scoping memo stating that a final decision is expected in early 2010.

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.

CONTINGENCIES

PG&E Corporation and the Utility have significant contingencies, including Chapter 11 disputed claims, tax matters, and environmental matters, which are discussed in Notes 10 and 11 of the Notes to the Condensed Consolidated Financial Statements.

REGULATORY MATTERS

This section of MD&A discusses developments that have occurred in significant pending regulatory proceedings discussed in the 2008 Annual Report and significant new pending regulatory proceedings that were initiated since the 2008 Annual Report was filed with the SEC. The outcome of these proceedings could have a significant effect on PG&E Corporation's and the Utility's results of operations and financial condition.

2011 General Rate Case Application

Unlike the current GRC, which set revenue requirements for a four-year period (2007 through 2010), it is expected that the next GRC will set revenue requirements for the Utility's electric and natural gas distribution operations and electric generation operations for a three-year period (2011 through 2013). On July 20, 2009, the Utility submitted a draft of its 2011 GRC application to the Division of Ratepayer Advocates ("DRA") of the CPUC, along with a notice indicating the Utility's intent to file the formal application with the CPUC by December 1, 2009. The Utility's broad goals in this GRC are to fund continued investments in safe and reliable service, meet the economic needs of the communities served by the Utility, and work toward a greener, smarter energy future consistent with state and national goals for long-term environmental sustainability.

The critical driver of the Utility's request in this GRC will be the need to invest in energy infrastructure to meet customers' expectations for service quality. Over the three years covered by this rate case (2011-2013), the Utility estimates it will need to spend an average of about \$2.7 billion in capital expenditures annually on these infrastructure improvements, especially replacement of gas and electric systems that are reaching the end of their useful lives. The Utility also needs adequate funds to continue to safely operate, maintain and upgrade generation plants to serve growing demand.

In the 2011 GRC, the CPUC will determine the amount of authorized base revenues that the Utility may collect from its customers to recover its basic business and operational costs for gas and electric distribution and electric generation operations for the period from 2011 through 2013. These revenue requirements are determined based on a forecast of costs for 2011. The draft application indicates that the Utility plans to request a revenue increase for 2011 of \$1.069 billion, or 6.5%, above the 2010 total revenue forecast.

The Utility plans to request that the CPUC adopt new flexible cost recovery mechanisms by establishing balancing accounts for several categories of costs that are subject to a high degree of volatility based on economic conditions and other uncontrollable factors, including costs incurred to establish new customer connections, uncollectible accounts, and employee healthcare costs.

The Utility also has indicated that it will seek a ratemaking mechanism for 2012 and 2013 designed to increase the Utility's authorized revenues in years between GRCs to reflect increases in rate base due to capital investments in infrastructure, and increases in wages and expenses. The proposed mechanism also would require revenue requirements to be adjusted to reflect changes in franchise, payroll, income, or property tax rates, as well as new taxes or fees imposed by governmental agencies. The Utility estimates that this mechanism would result in a revenue requirement increase of \$244 million in 2012 and an additional increase of \$326 million in 2013. The Utility would advise the CPUC of the actual amount of these proposed increases in October 2011 and October 2012 for years 2012 and 2013, respectively.

After the DRA reviews and accepts the draft GRC application, the Utility must wait 60 days to file the formal GRC application. After hearings are held, a proposed decision would be issued. A final CPUC decision is expected by the end of 2010.

PG&E Corporation and the Utility are unable to predict what amount of revenue requirements the CPUC will authorize for the period from 2011 through 2013, when a final decision in this proceeding will be received, or how the final decision will impact their financial condition or results of operations.

Electric Transmission Owner Rate Cases

On June 18, 2009, the FERC approved a settlement that sets the Utility's annual retail transmission base revenue requirement at \$776 million effective March 1, 2009. (For purposes of determining wholesale transmission rates, this retail revenue requirement is adjusted to \$763.5 million.) As part of the settlement, the Utility will refund any over-collected amounts to customers, with interest, through an adjustment to rates in 2011.

On July 30, 2009, the Utility filed an application with the FERC requesting an annual retail transmission revenue requirement of \$946 million, effective October 1, 2009. (For purposes of determining wholesale transmission rates, this retail revenue requirement request has been adjusted to \$932 million.) In accordance with past practice, the Utility expects that the FERC will suspend the requested increase for an

additional five months which would result in a March 1, 2010 effective date. The proposed rates represent an increase of \$170 million over current authorized revenue requirements.

PG&E Corporation and the Utility are unable to predict the outcome of this proceeding.

Energy Efficiency Programs and Incentive Ratemaking

The CPUC previously established an incentive ratemaking mechanism applicable to the California investor-owned utilities' implementation of their energy efficiency programs funded for the 2006-2008 and 2009-2011 program cycles. On December 18, 2008, based on their first interim claims, the CPUC awarded interim incentive earnings to the utilities for their 2006-2007 program performance. In the fourth quarter of 2008, the Utility recognized a CPUC award of \$41.5 million for the Utility's energy efficiency program performance in 2006-2007. Under the existing incentive ratemaking mechanism, the maximum amount of revenue that the Utility could earn and the maximum amount that the Utility could be required to reimburse customers over the 2006-2008 program cycle is \$180 million.

On January 29, 2009, the CPUC established a new rulemaking proceeding to modify the existing incentive ratemaking mechanism for programs beginning in 2009 and future years, to adopt a new framework to review the utilities' 2008 program performance, and to conduct a final review of the utilities' performance over the 2006-2008 program period. On May 21, 2009, the Utility, San Diego Gas & Electric Company, Southern California Gas Company, and the Natural Resources Defense Council, jointly requested that the CPUC approve a proposed settlement to resolve the utilities' interim claims for 2008 program performance and their final 2006-2008 true-up incentive claims. On July 10, 2009, the Utility submitted calculations, based on the methodology included in the proposed settlement, indicating that the Utility would be entitled to earn the remaining amount of the maximum incentives that could be earned for the 2006-2008 period. Based on the holdback amount proposed in the settlement, the Utility would be entitled to receive \$76.6 million in incentive earnings and an additional \$61.9 million would be held back and subject to verification in the final 2006-2008 true-up process to be completed in 2010.

The assigned administrative law judge has ruled that there will be no hearings on the settlement proposal. Nevertheless, in accordance with the current incentive claim process, the judge will permit the CPUC's Energy Division to issue its second verification report analyzing the utilities' 2008 energy efficiency program performance. The draft verification report is expected to be issued shortly and the parties will then be allowed to provide comments on the draft. It is uncertain what effect, if any, the issuance of the verification report will have on the likelihood of the proposed settlement becoming effective. The CPUC is expected to issue a final decision to resolve the 2006-2008 incentive claims before the end of 2009. Whether the proposed settlement will be approved and the amounts of any interim and final claims that may be awarded to the Utility are uncertain at this time.

On July 2, 2009, the Utility filed a supplement to its amended application for authorization of its 2009-2011 energy efficiency programs to incorporate certain policies adopted by the CPUC in a May 21, 2009 policy decision. As part of the Utility's supplement, it requested that the CPUC modify the 2009-2011 energy efficiency savings goals to reflect a variety of factors including: recent studies assessing the energy saving "potential" that exists in the market; changing energy savings assumptions, and the economic downturn. The CPUC is expected to issue a final decision authorizing the 2009-2011 programs before the end of 2009.

Spent Nuclear Fuel

As part of the Nuclear Waste Policy Act of 1982, Congress authorized the U.S. Department of Energy ("DOE") and electric utilities with commercial nuclear power plants to enter into contracts under which the DOE would be required to dispose of the utilities' spent nuclear fuel and high-level radioactive waste no later than January 31, 1998, in exchange for fees paid by the utilities. In 1983, the DOE entered into a contract with the Utility to dispose of nuclear waste from the Utility's two nuclear generating units at Diablo Canyon and its retired nuclear facility at Humboldt Bay. The DOE failed to develop a permanent storage site by January 31, 1998.

The Utility believes that the existing spent fuel pools at Diablo Canyon, which include newly constructed temporary storage racks, have sufficient capacity to enable the Utility to operate Diablo Canyon until approximately 2010 for Unit 1 and 2011 for Unit 2. Because the DOE failed to develop a permanent storage site, the Utility obtained a permit from the Nuclear Regulatory Commission ("NRC") to build an on-site dry cask storage facility to store spent fuel through at least 2024. The construction of the dry cask storage facility is complete and the initial movement of spent nuclear fuel to dry cask storage began in June 2009.

After various parties appealed the NRC's issuance of the permit, the U.S. Court of Appeals for the Ninth Circuit ("Ninth Circuit") issued a decision in 2006 requiring the NRC to issue a supplemental environmental assessment report on the potential environmental consequences in the event of terrorist attack at Diablo Canyon, as well as to review other contentions raised by the appealing parties related to potential terrorism threats. In August 2007, the NRC staff issued a final supplemental environmental assessment report concluding that there would be no significant environmental impacts from potential terrorist acts directed at the Diablo Canyon storage facility.

In October 2008, the NRC rejected the final contention that had been made during the appeal. The appellant has filed a petition for review of the NRC's order in the Ninth Circuit. On December 31, 2008, the appellate court granted the Utility's request to intervene in the proceeding. The Utility's brief on appeal was filed on April 8, 2009. No date has been set for oral argument.

As a result of the DOE's failure to build a national repository for nuclear waste, the Utility and other nuclear power plant owners sued the DOE to recover costs that they incurred to build on-site spent nuclear fuel storage facilities. The Utility seeks to recover approximately \$92 million of costs that it incurred through 2004. The DOE disputes the calculation of the recoverable amount conceding only that the Utility is entitled to recover approximately \$82 million of costs incurred through 2004. The U.S. Court of Federal Claims has ordered the trial for the remainder of the Utility's claim to begin on October 15, 2009.

PG&E Corporation and the Utility are unable to predict the amount that the Utility may ultimately receive for costs incurred through 2004. The Utility will also seek to recover costs incurred after 2004. Amounts recovered from the DOE will be credited to customers through rates.

Application to Recover Hydroelectric Facility Divestiture Costs

On April 16, 2009, the CPUC approved a decision to authorize the Utility to recover \$47 million, including \$12 million of interest, of costs that the Utility incurred in connection with its efforts to determine the market value of its hydroelectric generation facilities in 2000 and 2001. The Utility filed the application on April 14, 2008. These efforts were undertaken as required by the CPUC in connection with the proposed divestiture of the facilities to further the development of a competitive generation market in California. The CPUC subsequently withdrew this requirement. The Utility continues to own its hydroelectric generation assets. The Utility expects that the rate adjustments necessary to recover these authorized costs will be combined with other rate adjustments in the Utility's annual electric rate true-up proceeding. These rate changes are expected to become effective in January 2010.

Retirement Plan Contribution Application

On July 31, 2009, the Utility, the DRA, and the Coalition of California Utility Employees jointly requested the CPUC to approve an all-party settlement to resolve the Utility's March 2, 2009 application to annually adjust gas and electric revenue requirements, beginning in 2011, to allow the Utility to recover amounts necessary for the Utility's pension plan trust to attain fully funded status. The Utility proposed that the CPUC establish an annual adjustment mechanism to ensure the Utility's timely recovery of contributions necessary to meet funding obligations, including those caused by recent declining investment returns on trust assets and changes in federal requirements to adequately fund pension plans. Under the proposed settlement, in lieu of an annual adjustment mechanism, the Utility's authorized pension-related revenue requirements would be \$140.5 million, \$177.2 million, and \$215.7 million, in 2011, 2012, and 2013, respectively, to fund pension contributions to help restore the pension trust's fully funded status. In addition, the proposed settlement would allow the Utility to request an increase in revenue requirements if the ratio of trust assets to trust obligations falls below 85%.

The differences between pension benefit costs recognized in accordance with GAAP and amounts recognized for ratemaking purposes are recorded as a regulatory asset or liability as amounts are probable of recovery from customers. (See Note 3 of the Notes to the Condensed Consolidated Financial Statements.) Therefore, a settlement is not expected to impact net income in future periods. PG&E Corporation and the Utility cannot predict whether the CPUC will approve the proposed settlement.

RISK MANAGEMENT ACTIVITIES

The Utility and PG&E Corporation, mainly through its ownership of the Utility, are exposed to market risk, which is the risk that changes in market conditions will adversely affect net income or cash flows. PG&E Corporation and the Utility categorize market risks as price risk and interest rate risk. The Utility is also exposed to credit risk, which is the risk that counterparties fail to perform their contractual obligations. For a comprehensive discussion of PG&E Corporation's market risk, see the section entitled "Risk Management Activities" in the 2008 Annual Report.

Price Risk

Electricity Procurement

On April 1, 2009, the CAISO's Market Redesign and Technology Upgrade ("MRTU") became operative after having been delayed several times. Among other features, the MRTU established new day-ahead, hour-ahead, and real-time wholesale electricity markets subject to bid caps that increase over time. The Utility expects to continue to rely primarily on electricity from a diverse mix of resources including third-party contracts, amounts allocated under DWR contracts, and its own electricity generation facilities to meet customer demand. A relatively small proportion of the Utility's total customer demand must be met through purchases in the MRTU markets. As a result, exposure to price volatility in the new MRTU markets is minimal. The CAISO must implement additional FERC-ordered changes over the next several years. Market risks, if any, associated with these changes will be assessed as the design and timelines are finalized during the 2009-2010 period.

Natural Gas Transportation and Storage

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

The Utility's value-at-risk calculated under the methodology described above was \$14 million at June 30, 2009. The Utility's high, low, and average values-at-risk at June 30, 2009 were \$34 million, \$9 million, and \$21 million, respectively.

Interest Rate Risk

Interest rate risk sensitivity analysis is used to measure interest rate risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. At June 30, 2009, if interest rates changed by 1% for all current PG&E Corporation and the Utility variable rate and short-term debt and investments, the change would affect net income by approximately \$4 million, based on net variable rate debt and other interest rate-sensitive instruments outstanding.

Credit Risk

The Utility manages credit risk associated with its wholesale customers and counterparties by assigning credit limits based on evaluations of their financial conditions, net worth, credit ratings, and other credit criteria as deemed appropriate. Credit limits and credit quality are monitored periodically and a detailed credit analysis is performed at least annually. The Utility executes many energy contracts that require security (referred to as "credit collateral") in the form of cash, letters of credit, corporate guarantees of acceptable credit quality, or eligible securities if current net receivables and replacement cost exposure exceed contractually specified limits.

The following table summarizes the Utility's net credit risk exposure to its wholesale customers and counterparties, as well as the Utility's credit risk exposure to its wholesale customers or counterparties with a greater than 10% net credit exposure, at June 30, 2009 and December 31, 2008:

	Gross Credit Exposure Before Credit Collateral		Net Credit Exposure	Number of Wholesale Customers or Counterparties >10%	Net Exposure to Wholesale Customers or Counterparties >10%
(in millions)	(1)	Credit Collateral	(2)		
June 30, 2009	\$ 204	\$ 32	\$ 172	3	\$ 142
December 31, 2008	\$ 240	\$ 84	\$ 156	2	\$ 107

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

(2) Net credit exposure is the gross credit exposure minus credit collateral (cash deposits and letters of credit). For

purposes of this table, parental guarantees are not included as part of the calculation.

CRITICAL ACCOUNTING POLICIES

The preparation of Condensed Consolidated Financial Statements in accordance with accounting principles generally accepted in the United States of America involves the use of estimates and assumptions that affect the recorded amounts of assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The accounting policies described below are considered to be critical accounting policies, due, in part, to their complexity and because their application is relevant and material to the financial position and results of operations of PG&E Corporation and the Utility, and because these policies require the use of material judgments and estimates. Actual results may differ substantially from these estimates. These policies and their key characteristics are discussed in detail in the 2008 Annual Report. They include:

- regulatory assets and liabilities;
- environmental remediation liabilities;
- asset retirement obligations;
- accounting for income taxes; and
- pension and other postretirement plans.

For the period ended June 30, 2009, there were no changes in the methodology for computing critical accounting estimates, no additional accounting estimates met the standards for critical accounting policies, and there were no material changes to the important assumptions underlying the critical accounting estimates.

NEW ACCOUNTING POLICIES

Disclosures about Derivative Instruments and Hedging Activities - an amendment of FASB Statement No. 133

On January 1, 2009, PG&E Corporation and the Utility adopted Statement of Financial Accounting Standards (“SFAS”) No. 161, “Disclosures about Derivative Instruments and Hedging Activities - an amendment of FASB Statement No. 133” (“SFAS No. 161”). SFAS No. 161 amends and expands the disclosure requirements of SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities” (“SFAS No. 133”). SFAS No. 161 requires an entity to provide qualitative disclosures about its objectives and strategies for using derivative instruments and quantitative disclosures that detail the fair value amounts of, and gains and losses on, derivative instruments. SFAS No. 161 also requires disclosures about credit risk-related contingent features of derivative instruments. (See Note 7 of the Notes to the Condensed Consolidated Financial Statements.)

Noncontrolling Interests in Consolidated Financial Statements - an amendment of ARB No. 51

On January 1, 2009, PG&E Corporation and the Utility adopted SFAS No. 160, “Noncontrolling Interests in Consolidated Financial Statements - an amendment of ARB No. 51” (“SFAS No. 160”). SFAS No. 160 amends Accounting Research Bulletin No. 51, “Consolidated Financial Statements”, to establish accounting and reporting standards for a noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS No. 160 defines a “noncontrolling interest,” previously called a “minority interest,” as the portion of equity in a subsidiary not attributable, directly or indirectly, to a parent. Among other items, this standard requires that an entity include a noncontrolling interest in its consolidated statement of financial position within equity separate from the parent’s equity, report amounts inclusive of both the parent’s and noncontrolling interest’s shares in consolidated net income, and separately report the amounts of consolidated net income attributable to the parent and noncontrolling interest on the consolidated statement of operations. If a subsidiary is deconsolidated, any retained noncontrolling equity investment in the former subsidiary must be measured at fair value, and a gain or loss must be recognized in net income based on such fair value.

PG&E Corporation has reclassified its noncontrolling interest in the Utility from Preferred Stock of Subsidiaries to equity in PG&E Corporation’s Condensed Consolidated Financial Statements in accordance with SFAS No. 160 for all periods presented. The Utility had no material noncontrolling interests in consolidated subsidiaries as of June 30, 2009 and December 31, 2008.

The presentation and disclosure requirements of SFAS No. 160 were applied retrospectively. Other than the change in presentation of noncontrolling interests, adoption of SFAS No. 160 did not have a material impact on PG&E Corporation’s or the Utility’s Condensed Consolidated Financial Statements.

Issuer’s Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement

On January 1, 2009, PG&E Corporation and the Utility adopted Emerging Issues Task Force (“EITF”) 08-5, “Issuer’s Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement” (“EITF 08-5”). EITF 08-5 clarifies the unit of account in determining the fair value of a liability under SFAS No. 107, “Disclosures about Fair Value of Financial Instruments” (“SFAS No. 107”), or SFAS No. 133. Specifically, it requires an entity to exclude any third-party credit enhancements that are issued with, and are inseparable from, a debt instrument from the fair value measurement of that debt instrument. Adoption of EITF 08-5 did not have a material impact on PG&E Corporation’s or the Utility’s Condensed Consolidated Financial Statements.

Equity Method Investment Accounting

On January 1, 2009, PG&E Corporation and the Utility adopted EITF 08-6, “Equity Method Investment Accounting Considerations” (“EITF 08-6”). EITF 08-6 applies to investments accounted for under the equity method and requires an entity to measure its equity investment initially at cost. Generally, contingent consideration associated with an equity method investment should only be included in the initial measurement of that investment if it is required to be recognized by specific authoritative guidance other than SFAS No. 141 (revised 2007), “Business Combinations.” However, the investor in an equity method investment could be required to recognize a liability for the related contingent consideration features if the fair value of the investor’s share of the investee’s net assets exceeds the investor’s initial costs. An equity method investor is required to recognize other-than-temporary impairments of an equity method investment and shall account for a share issuance by an investee as if the investor had sold a proportionate share of its investment. Any gain or loss to the investor resulting from an investee’s share issuance shall be recognized in earnings. Adoption of EITF 08-6 did not have a material impact on PG&E Corporation’s or the Utility’s Condensed Consolidated Financial Statements.

Subsequent Events

On June 30, 2009, PG&E Corporation and the Utility adopted SFAS No. 165, “Subsequent Events” (“SFAS No. 165”). SFAS No. 165 does not significantly change the prior accounting practice for subsequent events except for the requirement to disclose the date through which an entity has evaluated subsequent events and the basis for that date. PG&E Corporation and the Utility have evaluated material subsequent events through August 5, 2009, the issue date of PG&E Corporation’s and the Utility’s Condensed Consolidated Financial Statements. Other than this disclosure, adoption of SFAS No. 165 did not have a material impact on PG&E Corporation’s or the Utility’s Condensed Consolidated Financial Statements.

Interim Disclosures about Fair Value of Financial Instruments

On June 30, 2009, PG&E Corporation and the Utility adopted Financial Accounting Standards Board (“FASB”) Staff Position (“FSP”) SFAS 107-1 and APB 28-1, “Interim Disclosures about Fair Value of Financial Instruments.” This FSP amends SFAS No. 107 and Accounting Principles Board Opinion No. 28, “Interim Financial Reporting,” to require disclosures about the fair value of financial instruments for interim reporting periods that were previously only required for annual reporting periods. An entity is required to disclose the fair value of financial assets and liabilities together with the related carrying amount and where the carrying amount is classified in the Condensed Consolidated Balance Sheets. (See Note 8 of the Notes to the Condensed Consolidated Financial Statements.)

Recognition and Presentation of Other-Than-Temporary Impairments

On June 30, 2009, PG&E Corporation and the Utility adopted FSP SFAS 115-2 and SFAS 124-2, “Recognition and Presentation of Other-Than-Temporary Impairments” (“FSP SFAS 115-2 and SFAS 124-2”). Under this FSP, to assess whether an other-than-temporary impairment exists for a debt security, an entity must (1) evaluate the likelihood of liquidating the debt security prior to recovering its cost basis and (2) determine if any impairment of the debt security is related to credit losses. In addition, this FSP requires enhanced disclosures of other-than-temporary impairments on debt and equity securities in the financial statements. Recognition and measurement guidance for other-than-temporary impairments of equity securities is not amended by this FSP. Adoption of FSP SFAS 115-2 and SFAS 124-2 did not have a material impact on PG&E Corporation’s or the Utility’s Condensed Consolidated Financial Statements.

Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly

On June 30, 2009, PG&E Corporation and the Utility adopted FSP SFAS 157-4, “Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly” (“FSP SFAS 157-4”). This FSP amends SFAS No. 157, “Fair Value Measurements” (“SFAS No. 157”), to provide guidance on estimating fair value when the volume or the level of activity for an asset or a liability has significantly decreased or when transactions are not orderly, when compared with normal market conditions. In particular, this FSP calls for adjustments to quoted prices or historical transaction data when estimating fair value in such circumstances. Guidance to identify such circumstances is also provided. Furthermore, this FSP requires fair value measurement disclosures made pursuant to SFAS No. 157 to be categorized by major security type, i.e., based on the nature and risks of the security. (See Note 8 of the Notes to the Condensed Consolidated Financial Statements.) Other than this change, adoption of FSP SFAS 157-4 did not have a material impact on PG&E Corporation’s or the Utility’s Condensed Consolidated Financial Statements.

ACCOUNTING PRONOUNCEMENTS ISSUED BUT NOT YET ADOPTED

Employers’ Disclosures about Postretirement Benefit Plan Assets

In December 2008, the FASB issued FSP SFAS 132(R)-1, “Employers’ Disclosures about Postretirement Benefit Plan Assets” (“FSP SFAS 132(R)-1”). FSP SFAS 132(R)-1 amends and expands the disclosure requirements of SFAS No. 132 (revised 2003), “Employers’ Disclosures about Pensions and Other Postretirement Benefits - an amendment of FASB Statements No. 87, 88, and 106.” An entity is required to provide qualitative disclosures about how investment allocation decisions are made, the inputs and valuation techniques used to measure the fair value of plan assets, and the concentration of risk within plan assets. Additionally, quantitative disclosures are required showing the fair value of each major category of plan assets, the levels in which each asset is classified within the fair value hierarchy, and a reconciliation for the period of plan assets that are measured using significant unobservable inputs. FSP SFAS 132(R)-1 is effective prospectively for PG&E Corporation and the Utility for the annual period ending December 31, 2009 and for subsequent annual periods. PG&E Corporation and the Utility will include the expanded disclosures described above in PG&E Corporation’s and the Utility’s Consolidated Financial Statements for such annual periods.

Accounting for Transfers of Financial Assets - an amendment of FASB Statement No. 140

In June 2009, the FASB issued SFAS No. 166, “Accounting for Transfers of Financial Assets - an amendment of FASB Statement No. 140” (“SFAS No. 166”). SFAS No. 166 eliminates the concept of a qualifying special-purpose entity and clarifies the requirements for derecognizing a financial asset and for applying sale accounting to a transfer of a financial asset. In addition, SFAS No. 166 requires an entity to disclose more information about transfers of financial assets, the entity’s continuing involvement, if any, with transferred financial assets, and the entity’s continuing risks, if any, from transferred financial assets. SFAS No. 166 is effective for PG&E Corporation and the Utility beginning on January 1, 2010. PG&E Corporation and the Utility are currently evaluating the impact of SFAS No. 166.

Amendments to FASB Interpretation No. 46(R)

In June 2009, the FASB issued SFAS No. 167, “Amendments to FASB Interpretation No. 46(R)” (“SFAS No. 167”). SFAS No. 167 amends FASB Interpretation No. 46 (revised December 2003), “Consolidation of Variable Interest Entities” (“FIN 46R”), regarding when and how to determine, or re-determine, whether an entity is a variable interest entity (“VIE”). In addition, SFAS No. 167 replaces FIN 46R’s quantitative approach for determining who has a controlling financial interest in a VIE with a qualitative approach. Furthermore, SFAS No. 167 requires ongoing assessments of whether an entity is the primary beneficiary of a VIE. SFAS No. 167 is effective prospectively for PG&E Corporation and the Utility beginning on January 1, 2010. PG&E Corporation and the Utility are currently evaluating the impact of SFAS No. 167.

The FASB Accounting Standards CodificationTM and the Hierarchy of Generally Accepted Accounting Principles - a replacement of FASB Statement No. 162

In June 2009, the FASB issued SFAS No. 168, “The FASB Accounting Standards CodificationTM and the Hierarchy of Generally Accepted Accounting Principles - a replacement of FASB Statement No. 162” (“SFAS No. 168”). SFAS No. 168 nullifies SFAS No. 162, “The Hierarchy of Generally Accepted Accounting Principles,” and defines authoritative GAAP for nongovernmental entities to be only comprised of the FASB Accounting Standards CodificationTM (“Codification”) and, for SEC registrants, guidance issued by the SEC. The Codification is a reorganization and compilation of all then-existing authoritative GAAP for nongovernmental entities, except for guidance issued by the SEC. PG&E Corporation and the Utility anticipate that adopting SFAS No. 168 will only change the referencing convention of GAAP in PG&E Corporation’s and the Utility’s Notes to the Condensed Consolidated Financial Statements. SFAS No. 168 is effective prospectively for PG&E

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 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 "Risk Management Activities" above under 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 June 30, 2009, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures are effective to ensure that information required to be disclosed by PG&E Corporation and the Utility in reports that the companies file or submit under the Securities Exchange Act of 1934 ("1934 Act") is recorded, processed, summarized, and reported within the time periods specified in the SEC rules and forms. In addition, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures were effective in ensuring that information required to be disclosed by PG&E Corporation and the Utility in the reports that PG&E Corporation and the Utility file or submit under the 1934 Act is accumulated and communicated to PG&E Corporation's and the Utility's management, including PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

There were no changes in internal control over financial reporting that occurred during the quarter ended June 30, 2009 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

Complaints Filed by the California Attorney General and the City and County of San Francisco

The complaint filed by the California Attorney General against PG&E Corporation and several of its present and former directors was dismissed on March 10, 2009 and the similar complaint filed by the City and County of San Francisco was dismissed on April 23, 2009. For more information regarding the resolution of these matters, see “Part I. Item 3. Legal Proceedings” in the 2008 Annual Report and “Part II, Item 1. Legal Proceedings” in PG&E Corporation’s and the Utility’s combined Quarterly Report on Form 10-Q for the quarter ended March 31, 2009.

ITEM 1A. RISK FACTORS

A discussion of the significant risks associated with investments in the securities of PG&E Corporation and the Utility is set forth under the heading “Management’s Discussion and Analysis of Financial Condition and Results of Operations - Risk Factors” in the 2008 Annual Report. The discussion of the potential impact of climate change appearing in the 2008 Annual Report under the heading “Management’s Discussion and Analysis of Financial Condition and Results of Operations - Risk Factors” under the following caption “*The Utility’s future operations may be impacted by climate change that may have a material impact on the Utility’s financial condition and results of operations*” is updated as follows to reflect new scientific evidence regarding climate change:

A report issued on June 16, 2009 by the U.S. Global Change Research Program (an interagency effort led by the National Oceanic and Atmospheric Administration) states that climate changes caused by rising emissions of carbon dioxide and other heat-trapping gases have already been observed in the United States, including increased frequency and severity of hot weather, reduced runoff from snow pack, and increased sea levels. The impact of events or conditions caused by climate change could range widely, from highly localized to worldwide, and the extent to which the Utility’s operations may be affected is uncertain. For example, if reduced snowpack decreases the Utility’s hydroelectric generation capacity, there will be a need for additional generation capacity from other sources. Under certain conditions, the events or conditions caused by climate change could result in a full or partial disruption of the ability of the Utility, or one or more entities on which it relies, to generate, transmit, transport or distribute electricity or natural gas. The Utility has been studying the potential effects of climate change on the Utility’s operations and is developing contingency plans to adapt to those events and conditions that the Utility believes are most likely to occur. Events or conditions caused by climate change could have a greater impact on the Utility’s operations than has been forecast and could result in lower revenues or increased expenses, or both. If the CPUC fails to adjust the Utility’s rates to reflect the impact of events or conditions caused by climate change, PG&E Corporation’s and the Utility’s financial condition, results of operations, and cash flows could be materially adversely affected.

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

During the quarter ended June 30, 2009, PG&E Corporation made equity contributions totaling \$125 million to the Utility in order to maintain the 52% common equity target authorized by the CPUC and to ensure that the Utility has adequate capital to fund its capital expenditures.

During the quarter ended June 30, 2009, PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. During the second quarter of 2009, the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

PG&E Corporation:

On May 13, 2009, PG&E Corporation held its annual meeting of shareholders. At the meeting, the shareholders voted as indicated below on the following matters:

1. Election of the following directors to serve until the next annual meeting of shareholders or until their successors are elected and qualified (included as Item 1 in the proxy statement):

	For	Against	Abstain
David R. Andrews	260,180,247	4,381,437	1,169,522
C. Lee Cox	259,858,613	4,731,971	1,140,622
Peter A. Darbee	259,218,162	5,489,392	1,023,652
Maryellen C. Herring	259,558,816	5,008,503	1,163,887
Roger H. Kimmel	261,024,544	3,486,603	1,220,059
Richard A. Meserve	252,048,376	12,532,659	1,150,171
Forrest E. Miller	261,197,670	3,397,224	1,136,312
Barbara L. Rambo	258,823,414	5,858,981	1,048,811
Barry Lawson Williams	251,196,096	13,431,653	1,103,457

Each director nominee was elected a director of PG&E Corporation. Each director nominee received affirmative votes from a majority of the shares represented and voting (excluding abstentions) with respect to the nominee's election, which shares voting affirmatively also constituted a majority of the required quorum.

2. Ratification of the appointment of Deloitte & Touche LLP as independent registered public accounting firm for 2009 (included as Item 2 in the proxy statement):

For:	261,716,319
Against:	3,349,443
Abstain:	665,444

This proposal was approved by a majority of the shares represented and voting (excluding abstentions) with respect to this proposal, which shares voting affirmatively also constituted a majority of the required quorum.

3. Consideration of a shareholder proposal regarding shareholder say on executive pay (included as Item 3 in the proxy statement):

For:	85,730,957
Against:	129,649,130
Abstain:	12,438,735
Broker Non-Vote ¹ :	37,912,384

This shareholder proposal was not approved, as the number of shares voting affirmatively on the proposal constituted less than a majority of the shares represented and voting (excluding abstentions and broker non-votes) with respect to the proposal.

¹ A non-vote occurs when brokers or nominees have voted on some of the matters to be acted on at a meeting, but do not vote on certain other matters because, under the rules of the New York Stock Exchange, they are not allowed to vote on those other matters without instructions from the beneficial owner of the shares. Broker non-votes are counted when determining whether the necessary quorum of shareholders is present or represented at each annual meeting.

4. Consideration of a shareholder proposal regarding shareholder reincorporation in North Dakota (included as Item 4 in the proxy statement):

For:	5,331,955
Against:	219,966,095
Abstain:	2,520,772
Broker Non- Vote ² :	37,912,384

This shareholder proposal was not approved, as the number of shares voting affirmatively on the proposal constituted less than a majority of the shares represented and voting (excluding abstentions and broker non-votes) with respect to the proposal.

Pacific Gas and Electric Company:

On May 13, 2009, the Utility held its annual meeting of shareholders. Shares of capital stock of the Utility consist of shares of common stock and shares of first preferred stock. PG&E Corporation owns all of the outstanding shares of common stock, approximately 96% of the combined voting power of the outstanding capital stock of the Utility. PG&E Corporation voted all of its shares of common stock for the nominees named in the 2009 joint proxy statement and for the ratification of the appointment of Deloitte & Touche LLP as independent registered public accounting firm for 2009. The balances of the votes shown below were cast by holders of shares of first preferred stock. At the annual meeting, the shareholders voted as indicated below on the following matters:

1. Election of the following directors to serve until the next annual meeting of shareholders or until their successors are elected and qualified (included as Item 1 in the proxy statement):

	For	Against	Abstain
David R. Andrews	271,967,457	158,076	46,770
C. Lee Cox	271,971,629	153,907	46,767
Peter A. Darbee	271,983,262	143,123	45,918
Maryellen C. Herringer	271,974,291	160,751	37,261
Roger H. Kimmel	271,986,056	146,337	39,910
Richard A. Meserve	271,979,187	143,461	49,655
Forrest E. Miller	271,984,004	140,631	47,668
Barbara L. Rambo	271,977,891	141,702	52,710
Barry Lawson Williams	271,944,498	178,715	49,090

Each director nominee was elected a director of Pacific Gas and Electric Company. Each director nominee received affirmative votes from a majority of the shares represented and voting (excluding abstentions) with respect to the nominee's election, which shares voting affirmatively also constituted a majority of the required quorum.

2. Ratification of the appointment of Deloitte & Touche LLP as independent registered public accounting firm for 2009 (included as Item 2 in the proxy statement):

For:	272,027,596
Against:	64,071
Abstain:	80,636

This proposal was approved by a majority of the shares represented and voting (excluding abstentions) with respect to this proposal, which shares voting affirmatively also constituted a majority of the required quorum.

² A non-vote occurs when brokers or nominees have voted on some of the matters to be acted on at a meeting, but do not vote on certain other matters because, under the rules of the New York Stock Exchange, they are not allowed to vote on those other matters without instructions from the beneficial owner of the shares. Broker non-votes are counted when determining whether the necessary quorum of shareholders is present or represented at each annual meeting.

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 six months ended June 30, 2009 was 3.15. The Utility's earnings to combined fixed charges and preferred stock dividends ratio for the six months ended June 30, 2009 was 3.09. The statement of the foregoing ratios, together with the statements of the computation of the foregoing ratios filed as Exhibits 12.1 and 12.2 hereto, are included herein for the purpose of incorporating such information and Exhibits into the Utility's Registration Statement Nos. 33-62488 and 333-149361 relating to various series of the Utility's first preferred stock and its senior notes, respectively.

PG&E Corporation's earnings to fixed charges ratio for the six months ended June 30, 2009 was 2.96. 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. 333-149360 relating to its senior notes.

ITEM 6. EXHIBITS

- 4.1 Seventh Supplemental Indenture, dated as of June 11, 2009 relating to the issuance of \$500,000,000 aggregate principal amount of Pacific Gas and Electric Company's Floating Rate Senior Notes due June 10, 2010 (incorporated by reference to Pacific Gas and Electric Company's Current Report on Form 8-K dated June 11, 2009 (File No. 1-2348), Exhibit 4.1)
- 10.1 Amendment and Limited Consent Agreement, dated as of April 27, 2009, by which Lehman Brothers Bank, FSB has been removed as a lender under the Amended and Restated Unsecured Revolving Credit Agreement entered into among PG&E Corporation, BNP Paribas, as administrative agent and a lender, Deutsche Bank Securities Inc., as syndication agent, ABN AMRO Bank, N.V., Bank of America, N.A., and Barclays Bank Plc, as documentation agents and lenders, and other lenders, dated February 26, 2007. (The Amended and Restated Unsecured Revolving Credit Agreement has previously been filed as Exhibit 10.1 to PG&E Corporation and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2007 (File No. 1-12609 and File No. 1-2348).)
- 10.2 Amendment and Limited Consent Agreement, dated as of April 27, 2009, by which Lehman Brothers Bank, FSB has been removed as a lender under the Amended and Restated Unsecured Revolving Credit Agreement entered into among Pacific Gas and Electric Company, Citicorp North America, Inc., as administrative agent and a lender, JPMorgan Securities Inc., as syndication agent, Barclays Bank Plc and BNP Paribas, as documentation agents and lenders, Deutsche Bank Securities Inc., as documentation agent, and other lenders, dated February 26, 2007. (The Amended and Restated Unsecured Revolving Credit Agreement has previously been filed as Exhibit 10.2 to PG&E Corporation's and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2007 (File No. 1-12609 and File No. 1-2348).)
- 11 Computation of Earnings Per Share
- 12.1 Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company
- 12.2 Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company
- 12.3 Computation of Ratios of Earnings to Fixed Charges for PG&E Corporation
- 31.1 Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002
- 31.2 Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002
- 32.1** Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002
- 32.2** Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002

**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

BARBARA L. BARCON

Barbara L. Barcon
Vice President, Finance and Chief Financial Officer
(duly authorized officer and principal financial officer)

Dated: August 5, 2009

EXHIBIT INDEX

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- 12.3 Computation of Ratios of Earnings to Fixed Charges for PG&E Corporation
- 31.1 Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002
- 31.2 Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002
- 32.1** Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002
- 32.2** Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002

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

AMENDMENT AND LIMITED CONSENT AGREEMENT

This AMENDMENT AND LIMITED CONSENT AGREEMENT (this “Agreement”), dated as of April 27, 2009, is entered into by and among PG&E CORPORATION, a California corporation (the “Borrower”), the several banks and other financial institutions or entities from time to time parties to the below-described Credit Agreement (the “Lenders”), each of the Issuing Lenders (as defined in the below-described Credit Agreement), and BNP PARIBAS, as administrative agent (the “Administrative Agent”), with respect to the following:

A. The Borrower, the Lenders, the Issuing Lenders and the Administrative Agent have previously entered into that certain Amended and Restated Credit Agreement, dated as of February 26, 2007 (the “Credit Agreement”). Capitalized terms are used in this Agreement as defined in the Credit Agreement, unless otherwise defined herein.

B. Lehman Brothers Bank, FSB (“Lehman”) has requested that the Borrower, the Lenders, the Issuing Lenders and the Administrative Agent consent and agree to the termination of Lehman Bank’s Commitment (it being understood that the termination of Lehman Bank’s Commitment shall not result in an increase in the amount of any Lender’s Commitment).

C. The Borrower, the Lenders, the Issuing Lenders and the Administrative Agent are willing to grant such request and to amend the Credit Agreement in certain respects on the terms and subject to the conditions set forth in this Agreement.

For good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto hereby agree as follows:

1. **Effectiveness**. The effectiveness of the provisions of Section 2, Section 3, Section 5 and Section 6 of this Agreement is subject to the satisfaction of the condition precedent described in Section 4 of this Agreement.

2. **Consent and Agreement**. On the terms and subject to the conditions of this Agreement, and notwithstanding anything to the contrary in the Credit Agreement (including Section 2.14 thereof), the Borrower, each Lender, each Issuing Lender and the Administrative Agent hereby consent and agree to the termination of Lehman Bank’s Commitment.

3. **Amendments to Credit Agreement**. On the terms and subject to the conditions of this Agreement, effective as of the Effective Date, Section 1.1 of the Credit Agreement is hereby amended to restate the definition of “L/C Commitment” to read in its entirety as follows:

“L/C Commitment”: \$87,235,282.08.

4. **Condition Precedent to the Effectiveness of this Agreement**. This Agreement shall become effective upon the Administrative Agent’s receipt of counterparts of this Agreement executed by the Borrower, the Lenders, the Issuing Lenders and the Administrative Agent (the first date on which the foregoing condition has been satisfied being

referred to herein as the “Effective Date”). The Administrative Agent shall promptly notify in writing the Borrower, the Lenders and the Issuing Lenders upon the satisfaction of the condition precedent to the Effective Date.

5. **Effect of this Agreement** . Upon the occurrence of the Effective Date:

(a) Lehman Bank’s Commitment shall terminate (thereby terminating Lehman Bank’s risk participations in all Letters of Credit issued on or prior to the Effective Date (each, an “Issued Letter of Credit”)), and each Lender’s Percentage after giving effect to the termination of Lehman Bank’s Commitment shall be as set forth on Schedule 1 to this Agreement (with respect to each Lender, such Percentage after giving effect to the termination of Lehman Bank’s Commitment being referred to herein as such Lender’s “Post-Consent Percentage”);

(b) the amount of each L/C Participant’s risk participation interest in each Issued Letter of Credit shall be automatically adjusted to equal such L/C Participant’s Post-Consent Percentage thereof; and

(c) Lehman Bank shall have no further rights or obligations under the Credit Agreement, other than those rights and obligations which, by their terms, survive the termination of any of the Commitments and/or the repayment in full of the Obligations.

For the avoidance of doubt, nothing contained in this Agreement shall have the effect of increasing the amount of any Lender’s Commitment.

6. **Payment of Fees to Lehman Bank** . This Agreement shall in no way be deemed to waive, alter or otherwise modify the pro rata sharing provisions of Section 2.14 of the Credit Agreement with respect to the fees payable to Lehman Bank under Section 2.6(a), Section 2.6(b) or Section 3.3 of the Credit Agreement. In that regard, any fees under Section 2.6(a), Section 2.6(b) or Section 3.3 of the Credit Agreement owing to Lehman Bank with respect to its Commitment through the Effective Date shall be paid on the next date on which such fees and other amounts are paid to the other Lenders pursuant to the Credit Agreement. Thereafter, the Borrower shall not be required to pay for the account of Lehman Bank, and Lehman Bank shall not be entitled to receive, any fees under Section 2.6(a), Section 2.6(b) or Section 3.3 of the Credit Agreement.

7. **Representations and Warranties** . In order to induce the Issuing Lenders, the Lenders and the Administrative Agent to enter into this Agreement, the Borrower represents and warrants to each Lender, each Issuing Lender and the Administrative Agent that, as of the date hereof, (a) no Event of Default has occurred and is continuing or, after giving effect to the consent set forth in Section 2, would result from the effectiveness of this Agreement; and (b) the representations and warranties of the Borrower contained in Section 4 of the Credit Agreement are true and correct in all material respects as of the Effective Date with the same effect as though such representations and warranties had been made on and as of the Effective Date (except for such representations and warranties made as of a specified date, which shall be true and correct in all material respects as of such specified date).

8. **Miscellaneous**.

(a) Reference to and Effect on the Credit Agreement and the other Loan Documents.

(i) Except as specifically modified by this Agreement, the Credit Agreement and the other Loan Documents shall remain in full force and effect and are hereby ratified and confirmed by the Borrower in all respects.

(ii) The execution and delivery of this Agreement shall not, except as expressly provided herein, constitute a waiver of any provision of, or operate as a waiver of any right, power or remedy of the Lenders, the Issuing Lenders or the Administrative Agent under, the Credit Agreement or any of the other Loan Documents.

(iii) Upon the occurrence of the Effective Date, this Agreement shall be construed as one with the Credit Agreement, and the Credit Agreement shall, where the context requires, be read and construed throughout so as to incorporate this Agreement.

(iv) If there is any conflict between the terms and provisions of this Agreement and the terms and provisions of the Credit Agreement or any other Loan Document, the terms and provisions of this Agreement shall govern.

(b) Headings. Section and subsection headings in this Agreement are included for convenience of reference only and shall not constitute a part of this Agreement for any other purpose or be given any substantive effect.

(c) Counterparts. This Agreement may be executed by one or more of the parties to this Agreement in any number of separate counterparts, and all of said counterparts taken together shall be deemed to constitute one and the same instrument. Delivery of an executed signature page of this Agreement by facsimile transmission shall be effective as delivery of a manually executed counterpart hereof. A set of the copies of this Agreement signed by all parties shall be lodged with the Borrower and the Administrative Agent.

(d) **GOVERNING LAW**. **THIS AGREEMENT AND THE RIGHTS AND OBLIGATIONS OF THE PARTIES UNDER THIS AGREEMENT SHALL BE GOVERNED BY, AND CONSTRUED AND INTERPRETED IN ACCORDANCE WITH, THE LAWS OF THE STATE OF NEW YORK.**

9. **Loan Documents**. This Agreement is a Loan Document as defined in the Credit Agreement, and the provisions of the Credit Agreement generally applicable to Loan Documents are applicable hereto and incorporated herein by this reference.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be duly executed as of the date first above written.

PG&E CORPORATION

By: NICHOLAS BIJUR
Name: NICHOLAS BIJUR
Title: Assistant Treasurer

-Signature Page-
Amendment and Limited Consent Agreement
PG&E Corporation

BNP PARIBAS, as Administrative Agent, Issuing Lender and as a Lender

By: FRANCES J. DELANEY
Name: FRANCES J. DELANEY
Title: Managing Director

By: MANOJ KHATRI
Name: MANOJ KHATRI
Title: Director

-Signature Page-
Amendment and Limited Consent Agreement
PG&E Corporation

JPMORGAN CHASE BANK, N.A.,
as a Lender

By: JUAN JAVELLANA
Name: JUAN JAVELLANA
Title: Vice President

-Signature Page-
Amendment and Limited Consent Agreement
PG&E Corporation

DEUTSCHE BANK AG, New York Branch,
as a Lender

By: MARCUS TARKINGTON
Name: MARCUS TARKINGTON
Title: Director

By: RAINER MEIER
Name: RAINER MEIER
Title: Director

-Signature Page-
Amendment and Limited Consent Agreement
PG&E Corporation

CITICORP NORTH AMERICA, INC.,
as a Lender

By: NIETZSCHE RODRICKS
Name: NIETZSCHE RODRICKS
Title: Vice President

-Signature Page-
Amendment and Limited Consent Agreement
PG&E Corporation

BARCLAYS BANK Plc,
as a Lender

By: DAVID BARTON
Name: DAVID BARTON
Title: Director

-Signature Page-
Amendment and Limited Consent Agreement
PG&E Corporation

BANK OF AMERICA, N.A.,
as a Lender

By: PATRICK MARTIN
Name: PATRICK MARTIN
Title: Vice President

-Signature Page-
Amendment and Limited Consent Agreement
PG&E Corporation

UBS LOAN FINANCE LLC,
as a Lender

By: MARIE HADDAD
Name: MARIE HADDAD
Title: Associate Director

By: MARY E. EVANS
Name: MARY E. EVANS
Title: Associate Director

-Signature Page-
Amendment and Limited Consent Agreement
PG&E Corporation

THE BANK OF NEW YORK MELLON,
as a Lender

By: MARK W. ROGERS
Name: MARK W. ROGERS
Title: Vice President

-Signature Page-
Amendment and Limited Consent Agreement
PG&E Corporation

WILLIAM STREET COMMITMENT CORPORATION
(Recourse only to the assets of William Street Commitment
Corporation),
as a Lender

By: MARK WALTON
Name: MARK WALTON
Title: Assistant Vice President

-Signature Page-
Amendment and Limited Consent Agreement
PG&E Corporation

UNION BANK OF CALIFORNIA, N.A.,
as a Lender

By: DENNIS G. BLANK
Name: DENNIS G. BLANK
Title: Vice President

-Signature Page-
Amendment and Limited Consent Agreement
PG&E Corporation

ABN AMRO BANK N.V.,
as a Lender

By: R. SCOTT DONALDSON
Name: R. SCOTT DONALDSON
Title: Director

By: TODD VAUBEL
Name: TODD VAUBEL
Title: Vice President

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-Signature Page-
Amendment and Limited Consent Agreement
PG&E Corporation

MORGAN STANLEY BANK,
as a Lender

By: MELISSA JAMES
Name: MELISSA JAMES
Title: Authorized Signatory

-Signature Page-
Amendment and Limited Consent Agreement
PG&E Corporation

MIZUHO CORPORATE BANK, LTD.,
as a Lender

By: RAYMOND VENTURA
Name: RAYMOND VENTURA
Title: Deputy General Manager

-Signature Page-
Amendment and Limited Consent Agreement
PG&E Corporation

LEHMAN BROTHERS BANK, FSB,
as a Lender

By: THEODORE JANULIS
Name: THEODORE JANULIS
Title: Chairman

-Signature Page-
Amendment and Limited Consent Agreement
PG&E Corporation

U.S. BANK NATIONAL ASSOCIATION,
as a Lender

By: RAYMOND J. PALMER
Name: RAYMOND J. PALMER
Title: Senior Vice President

-Signature Page-
Amendment and Limited Consent Agreement
PG&E Corporation

Schedule 1 to Amendment and Limited Consent Agreement

Post-Consent Percentages

JPMorgan Chase Bank, N.A.	11.36245778%
Citicorp North America, Inc.	11.36245778%
BNP Paribas	9.139902688%
Deutsche Bank AG, NY Branch	9.139902688%
Barclays Bank PLC	9.139902688%
Bank of America, N.A.	9.139902688%
The Bank of New York, Mellon	6.817474665%
UBS Loan Finance LLC	6.817474665%
ABN AMRO Bank N.V.	5.113105999%
Morgan Stanley Bank	5.113105999%
Union Bank of California, N.A.	5.113105999%
Williams Street Commitment Corporation	5.113105999%
Mizuho Corporate Bank, Ltd.	4.734357404%
US Bank National Association	1.893742964%
<i>TOTAL</i>	100.000000000%

AMENDMENT AND LIMITED CONSENT AGREEMENT

This AMENDMENT AND LIMITED CONSENT AGREEMENT (this “Agreement”), dated as of April 27, 2009, is entered into by and among PACIFIC GAS AND ELECTRIC COMPANY, a California corporation (the “Borrower”), the several banks and other financial institutions or entities from time to time parties to the below-described Credit Agreement (the “Lenders”), each of the Issuing Lenders (as defined in the below-described Credit Agreement), and CITICORP NORTH AMERICA, INC., as administrative agent (the “Administrative Agent”), with respect to the following:

A. The Borrower, the Lenders, the Issuing Lenders and the Administrative Agent have previously entered into that certain Amended and Restated Credit Agreement, dated as of February 26, 2007 (the “Credit Agreement”). Capitalized terms are used in this Agreement as defined in the Credit Agreement, unless otherwise defined herein.

B. On March 2, 2009, the Borrower, through the Administrative Agent, made a request for borrowing of Revolving Loans to the Lenders in an amount equal to \$309,324,256.18 (the “Specified Borrowing Amount”), the proceeds of which would be made available to the Borrower on March 3, 2009 (the “Specified Borrowing Date”). Lehman Brothers Bank, FSB (“Lehman”) failed to make available to the Administrative Agent for the account of the Borrower Lehman Bank’s pro rata share of the Specified Borrowing Amount on the Specified Borrowing Date.

C. Lehman Bank has requested that the Borrower, the Lenders, the Issuing Lenders and the Administrative Agent consent and agree to the termination of Lehman Bank’s Commitment (it being understood that the termination of Lehman Bank’s Commitment shall not result in an increase in the amount of any Lender’s Commitment).

D. The Borrower, the Lenders, the Issuing Lenders and the Administrative Agent are willing to grant such request and to amend the Credit Agreement in certain respects on the terms and subject to the conditions set forth in this Agreement.

For good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto hereby agree as follows:

1. **Effectiveness**. The effectiveness of the provisions of Section 2, Section 3, Section 5 and Section 6 of this Agreement is subject to the satisfaction of the condition precedent described in Section 4 of this Agreement.

2. **Consent and Agreement**. On the terms and subject to the conditions of this Agreement, and notwithstanding anything to the contrary in the Credit Agreement (including Section 2.14 thereof), the Borrower, each Lender, each Issuing Lender and the Administrative Agent hereby consent and agree to the termination of Lehman Bank’s Commitment.

3. **Amendments to Credit Agreement**. On the terms and subject to the conditions of this Agreement, effective as of the Effective Date:

(a) Section 1.1 of the Credit Agreement is hereby amended to restate the definition of “L/C Commitment” to read in its entirety as follows:

“L/C Commitment”: \$921,363,243.60.

(b) Section 2.2 of the Credit Agreement is hereby amended to delete the first sentence thereof in its entirety and substitute the following therefor:

“The Borrower may borrow under the Commitments during the Commitment Period on any Business Day, provided that the Borrower shall give the Administrative Agent irrevocable notice (which notice must be received by the Administrative Agent: (a) prior to 12:00 Noon, New York City time, three Business Days prior to the requested Borrowing Date, in the case of Eurodollar Loans, or (b) prior to 11:00 A.M., New York City time, on the requested Borrowing Date, in the case of ABR Loans) specifying (i) the amount and Type of Revolving Loans to be borrowed, (ii) the requested Borrowing Date and (iii) in the case of Eurodollar Loans, the respective amounts of each such Type of Loan and the respective lengths of the initial Interest Period therefor.”

4. **Condition Precedent to the Effectiveness of this Agreement**. This Agreement shall become effective upon the Administrative Agent’s receipt of counterparts of this Agreement executed by the Borrower, the Lenders, the Issuing Lenders and the Administrative Agent (the first date on which the foregoing condition has been satisfied being referred to herein as the “Effective Date”). The Administrative Agent shall promptly notify in writing the Borrower, the Lenders and the Issuing Lenders upon the satisfaction of the condition precedent to the Effective Date.

5. **Effect of this Agreement**. Upon the occurrence of the Effective Date:

(a) Lehman Bank’s Commitment shall terminate (thereby terminating Lehman Bank’s risk participations in all Letters of Credit issued on or prior to the Effective Date (each, an “Issued Letter of Credit”)), and each Lender’s Percentage after giving effect to the termination of Lehman Bank’s Commitment shall be as set forth on Schedule 1 to this Agreement (with respect to each Lender, such Percentage after giving effect to the termination of Lehman Bank’s Commitment being referred to herein as such Lender’s “Post-Consent Percentage”);

(b) the amount of each L/C Participant’s risk participation interest in each Issued Letter of Credit shall be automatically adjusted to equal such L/C Participant’s Post-Consent Percentage thereof;

(c) the Non-Procurement Facility Limit shall be automatically reduced to \$1,018,348,848.20 and the Procurement L/C Facility Limit shall be automatically reduced to \$921,363,243.60; and

(d) Lehman Bank shall have no further rights or obligations under the Credit Agreement, other than those rights and obligations which, by their terms, survive the termination of any of the Commitments and/or the repayment in full of the Obligations.

For the avoidance of doubt, nothing contained in this Agreement shall have the effect of increasing the amount of any Lender's Commitment.

6. **Payment of Fees to Lehman Bank** . This Agreement shall in no way be deemed to waive, alter or otherwise modify the pro rata sharing provisions of Section 2.14 of the Credit Agreement with respect to the fees payable to Lehman Bank under Section 2.6(a), Section 2.6(b) or Section 3.3 of the Credit Agreement. In that regard, any fees under Section 2.6(a), Section 2.6(b) or Section 3.3 of the Credit Agreement owing to Lehman Bank with respect to its Commitment through the Effective Date shall be paid on the next date on which such fees and other amounts are paid to the other Lenders pursuant to the Credit Agreement. Thereafter, the Borrower shall not be required to pay for the account of Lehman Bank, and Lehman Bank shall not be entitled to receive, any fees under Section 2.6(a), Section 2.6(b) or Section 3.3 of the Credit Agreement.

7. **Representations and Warranties** . In order to induce the Issuing Lenders, the Lenders and the Administrative Agent to enter into this Agreement, the Borrower represents and warrants to each Lender, each Issuing Lender and the Administrative Agent that, as of the date hereof, (a) no Event of Default has occurred and is continuing or, after giving effect to the consent set forth in Section 2, would result from the effectiveness of this Agreement; and (b) the representations and warranties of the Borrower contained in Section 4 of the Credit Agreement are true and correct in all material respects as of the Effective Date with the same effect as though such representations and warranties had been made on and as of the Effective Date (except for such representations and warranties made as of a specified date, which shall be true and correct in all material respects as of such specified date).

8. **Miscellaneous** .

(a) **Reference to and Effect on the Credit Agreement and the other Loan Documents** .

(i) Except as specifically modified by this Agreement, the Credit Agreement and the other Loan Documents shall remain in full force and effect and are hereby ratified and confirmed by the Borrower in all respects.

(ii) The execution and delivery of this Agreement shall not, except as expressly provided herein, constitute a waiver of any provision of, or operate as a waiver of any right, power or remedy of the Lenders, the Issuing Lenders or the Administrative Agent under, the Credit Agreement or any of the other Loan Documents.

(iii) Upon the occurrence of the Effective Date, this Agreement shall be construed as one with the Credit Agreement, and the Credit Agreement shall, where the context requires, be read and construed throughout so as to incorporate this Agreement.

(iv) If there is any conflict between the terms and provisions of this Agreement and the terms and provisions of the Credit Agreement or any other Loan Document, the terms and provisions of this Agreement shall govern.

(b) Headings. Section and subsection headings in this Agreement are included for convenience of reference only and shall not constitute a part of this Agreement for any other purpose or be given any substantive effect.

(c) Counterparts. This Agreement may be executed by one or more of the parties to this Agreement in any number of separate counterparts, and all of said counterparts taken together shall be deemed to constitute one and the same instrument. Delivery of an executed signature page of this Agreement by facsimile transmission shall be effective as delivery of a manually executed counterpart hereof. A set of the copies of this Agreement signed by all parties shall be lodged with the Borrower and the Administrative Agent.

(d) **GOVERNING LAW. THIS AGREEMENT AND THE RIGHTS AND OBLIGATIONS OF THE PARTIES UNDER THIS AGREEMENT SHALL BE GOVERNED BY, AND CONSTRUED AND INTERPRETED IN ACCORDANCE WITH, THE LAWS OF THE STATE OF NEW YORK.**

9. **Loan Documents.** This Agreement is a Loan Document as defined in the Credit Agreement, and the provisions of the Credit Agreement generally applicable to Loan Documents are applicable hereto and incorporated herein by this reference.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be duly executed as of the date first above written.

PACIFIC GAS AND ELECTRIC COMPANY

By:	<u>NICHOLAS BIJUR</u>
Name:	<u>NICHOLAS BIJUR</u>
Title:	<u>Assistant Treasurer</u>

-Signature Page-
Amendment and Limited Consent Agreement
Pacific Gas and Electric Company

CITICORP NORTH AMERICA, INC.,
as Administrative Agent and as a Lender

By: MAUREEN MARONEY
Name: MAUREEN MARONEY
Title: Authorized Signatory

-Signature Page-
Amendment and Limited Consent Agreement
Pacific Gas and Electric Company

JPMORGAN CHASE BANK, N.A.,
as a Lender

By: JUAN JAVELLANA
Name: JUAN JAVELLANA
Title: Vice President

-Signature Page-
Amendment and Limited Consent Agreement
Pacific Gas and Electric Company

DEUTSCHE BANK AG, New York Branch,
as a Lender

By: MARCUS TARKINGTON
Name: MARCUS TARKINGTON
Title: Director

By: RAINER MEIER
Name: RAINER MEIER
Title: Director

-Signature Page-
Amendment and Limited Consent Agreement
Pacific Gas and Electric Company

BNP PARIBAS, as a Lender

By: FRANCES J. DELANEY
Name: FRANCES J. DELANEY
Title: Managing Director

By: MANOJ KHATRI
Name: MANOJ KHATRI
Title: Director

-Signature Page-
Amendment and Limited Consent Agreement
Pacific Gas and Electric Company

BARCLAYS BANK PLC,
as a Lender

By: ALICIA BORYS
Name: ALICIA BORYS
Title: Assistant Vice President

-Signature Page-
Amendment and Limited Consent Agreement
Pacific Gas and Electric Company

BANK OF AMERICA, N.A.,
as a Lender

By: PATRICK MARTIN
Name: PATRICK MARTIN
Title: Vice President

-Signature Page-
Amendment and Limited Consent Agreement
Pacific Gas and Electric Company

UBS LOAN FINANCE LLC,
as a Lender

By: MARIE HADDAD
Name: MARIE HADDAD
Title: Associate Director

By: MARY E. EVANS
Name: MARY E. EVANS
Title: Associate Director

-Signature Page-
Amendment and Limited Consent Agreement
Pacific Gas and Electric Company

THE BANK OF NEW YORK MELLON,
as a Lender

By: MARK W. ROGERS
Name: MARK W. ROGERS
Title: Vice President

-Signature Page-
Amendment and Limited Consent Agreement
Pacific Gas and Electric Company

WILLIAM STREET COMMITMENT CORPORATION
(Recourse only to the assets of William Street Commitment
Corporation),
as a Lender

By: MARK WALTON
Name: MARK WALTON
Title: Assistant Vice President

-Signature Page-
Amendment and Limited Consent Agreement
Pacific Gas and Electric Company

UNION BANK OF CALIFORNIA, N.A.,
as a Lender

By: DENNIS G. BLANK
Name: DENNIS G. BLANK
Title: Vice President

-Signature Page-
Amendment and Limited Consent Agreement
Pacific Gas and Electric Company

ABN AMRO BANK N.V.,
as a Lender

By: R. SCOTT DONALDSON
Name: R. SCOTT DONALDSON
Title: Director

By: TODD VAUBEL
Name: TODD VAUBEL
Title: Vice President

-Signature Page-
Amendment and Limited Consent Agreement
Pacific Gas and Electric Company

MORGAN STANLEY BANK, N.A.
as a Lender

By: MELISSA JAMES
Name: MELISSA JAMES
Title: Authorized Signatory

-Signature Page-
Amendment and Limited Consent Agreement
Pacific Gas and Electric Company

MIZUHO CORPORATE BANK, LTD.,
as a Lender

By: RAYMOND VENTURA
Name: RAYMOND VENTURA
Title: Deputy General Manager

-Signature Page-
Amendment and Limited Consent Agreement
Pacific Gas and Electric Company

SUMITOMO MITSUI BANKING CORPORATION,
as a Lender

By: MASAKAZU HASEGAWA
Name: MASAKAZU HASEGAWA
Title: General Manager

-Signature Page-
Amendment and Limited Consent Agreement
Pacific Gas and Electric Company

LEHMAN BROTHERS BANK, FSB,
as a Lender

By: THEODORE JANULIS
Name: THEODORE JANULIS
Title: Chairman

-Signature Page-
Amendment and Limited Consent Agreement
Pacific Gas and Electric Company

U.S. BANK NATIONAL ASSOCIATION,
as a Lender

By: RAYMOND J. PALMER
Name: RAYMOND J. PALMER
Title: Senior Vice President

-Signature Page-
Amendment and Limited Consent Agreement
Pacific Gas and Electric Company

COMMERZBANK AG, New York Branch and Grand Cayman
Branches, as a Lender

By: ANDREW CAMPBELL
Name: ANDREW CAMPBELL
Title: Senior Vice President

By: ELI DAVIS
Name: ELI DAVIS
Title: Assistant Vice President

-Signature Page-
Amendment and Limited Consent Agreement
Pacific Gas and Electric Company

Schedule 1 to Amendment and Limited Consent Agreement

Post-Consent Percentages

JPMorgan Chase Bank, N.A.	10.967880217%
Citicorp North America, Inc.	9.679029150%
Deutsche Bank AG, NY Branch	8.822506526%
BNP Paribas	8.822506526%
Barclays Bank PLC	8.822506526%
Bank of America, N.A.	8.822506526%
UBS Loan Finance LLC	6.580728130%
The Bank of New York, Mellon	6.580728130%
Williams Street Commitment Corporation	4.935546097%
Union Bank of California, N.A.	4.935546097%
ABN AMRO Bank N.V.	4.935546097%
Morgan Stanley Bank	4.935546097%
Mizuho Corporate Bank, Ltd.	4.569950091%
Sumitomo Mitsui Banking Corporation	3.472642683%
US Bank National Association	1.827980036%
Commerzbank, AG, NY Branch	1.288851068%
<i>TOTAL</i>	100.000000000%

PACIFIC GAS AND ELECTRIC COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Three Months Ended June 30,	Six Months Ended June 30,	Year Ended December 31,				
	2009	2009	2008	2007	2006	2005	2004
Earnings:							
Income from continuing operations	\$ 391	\$ 630	\$ 1,199	\$ 1,024	\$ 985	\$ 934	\$ 3,982
Income taxes provision	132	263	488	571	602	574	2,561
Net fixed charges	203	415	860	889	801	589	695
Total Earnings	\$ 726	1,308	\$ 2,547	\$ 2,484	\$ 2,388	\$ 2,097	\$ 7,238
Fixed Charges:							
Interest and amortization of premiums, discounts and capitalized expenses related to short-term borrowings and long-term debt, net	\$ 188	\$ 383	\$ 794	\$ 834	\$ 770	\$ 573	\$ 682
Interest on capital leases	5	10	22	23	11	1	1
AFUDC debt	10	22	44	32	20	15	12
Total Fixed Charges	\$ 203	\$ 415	\$ 860	\$ 889	\$ 801	\$ 589	\$ 695
Ratios of Earnings to Fixed Charges	3.58	3.15	2.96	2.79	2.98	3.56	10.41

Note:

For the purpose of computing Pacific Gas and Electric Company's ratios of earnings to fixed charges, "earnings" represent income from continuing operations adjusted for income taxes and fixed charges (excluding capitalized interest). "Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, and AFUDC debt. Fixed charges exclude interest on tax liabilities in accordance with FASB Interpretation No. 48 (Accounting for Uncertainty in Income Taxes).

PACIFIC GAS AND ELECTRIC COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO COMBINED
FIXED CHARGES AND PREFERRED STOCK DIVIDENDS

	Three Month Ended June 30, 2009	Six Months Ended June 30, 2009	2008	2007	Year Ended December 31,			2004
	2009	2009			2006	2005		
Earnings:								
Income from continuing operations	\$ 391	\$ 630	\$ 1,199	\$ 1,024	\$ 985	\$ 934	\$	3,982
Income taxes provision	132	263	488	571	602	574		2,561
Net fixed charges	203	415	860	889	801	589		695
Total Earnings	\$ 726	\$ 1,308	\$ 2,547	\$ 2,484	\$ 2,388	\$ 2,097		\$ 7,238
Fixed Charges:								
Interest and amortization of premiums, discounts and capitalized expenses related to short-term borrowings and long-term debt, net	\$ 188	\$ 383	\$ 794	\$ 834	\$ 770	\$ 573	\$	682
Interest on capital leases	5	10	22	23	11	1		1
AFUDC debt	10	22	44	32	20	15		12
Total Fixed Charges	\$ 203	\$ 415	\$ 860	\$ 889	\$ 801	\$ 589		\$ 695
Preferred Stock Dividends:								
Tax deductible dividends	2	4	9	9	12	9		9
Pre-tax earnings required to cover non-tax deductible preferred stock dividend requirements	3	4	7	8	3	12		20
Total Preferred Stock Dividends	5	8	16	17	15	21		29
Total Combined Fixed Charges and Preferred Stock Dividends	\$ 208	\$ 423	\$ 876	\$ 906	\$ 816	\$ 610		\$ 724
Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends								
	3.49	3.09	2.91	2.74	2.93	3.44		10.00

Note:

For the purpose of computing Pacific Gas and Electric Company's ratios of earnings to combined fixed charges and preferred stock dividends, "earnings" represent income adjusted for income taxes and fixed charges (excluding capitalized interest). "Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and

expense, interest on capital leases, and AFUDC debt. "Preferred stock dividends" represent tax deductible dividends and pre-tax earnings that are required to pay the dividends on the outstanding series of preferred stock. Fixed charges exclude interest on tax liabilities in accordance with FASB Interpretation No. 48 (Accounting for Uncertainty in Income Taxes).

PG&E CORPORATION
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Three Months Ended June 30,	Six Months Ended June 30,	Year Ended December 31,				
	2009	2009	2008	2007	2006	2005	2004
Earnings:							
Income from continuing operations	\$ 392	\$ 636	\$ 1,198	\$ 1,020	\$ 1,005	\$ 920	\$ 3,841
Income taxes provision	125	240	425	539	554	544	2,466
Net fixed charges	220	443	907	937	845	639	855
Pre-tax earnings required to cover the preferred stock dividend of consolidated subsidiaries	(5)	(8)	(16)	(17)	(15)	(20)	(29)
Total Earnings	\$ 732	\$ 1,311	\$ 2,514	\$ 2,479	\$ 2,389	\$ 2,083	\$ 7,133
Fixed Charges:							
Interest and amortization of premiums, discounts and capitalized expenses related to short-term borrowings and long-term debt, net	\$ 200	\$ 403	\$ 825	\$ 865	\$ 799	\$ 603	\$ 813
Interest on capital leases	5	10	22	23	11	1	1
AFUDC debt	10	22	44	32	20	15	12
Pre-tax earnings required to cover the preferred stock dividend of consolidated subsidiaries	5	8	16	17	15	20	29
Total Fixed Charges	\$ 220	\$ 443	\$ 907	\$ 937	\$ 845	\$ 639	\$ 855
Ratios of Earnings to Fixed Charges	3.33	2.96	2.77	2.65	2.83	3.26	8.34

Note:

For the purpose of computing PG&E Corporation's ratios of earnings to fixed charges, "earnings" represent income from continuing operations adjusted for income taxes, fixed charges (excluding capitalized interest), and pre-tax earnings required to cover the preferred stock dividend of consolidated subsidiaries. "Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, AFUDC debt, and earnings required to cover preferred stock dividends of consolidated subsidiaries. Fixed charges exclude interest on tax liabilities in accordance with FASB Interpretation No. 48 (Accounting for Uncertainty in Income Taxes).

PG&E CORPORATION
COMPUTATION OF EARNINGS PER SHARE

(in millions, except per share amounts)	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Income Available for Common Shareholders	\$ 388	\$ 293	\$ 629	\$ 517
Less: distributed earnings to common shareholders	155	139	309	278
Undistributed earnings	<u>\$ 233</u>	<u>\$ 154</u>	<u>\$ 320</u>	<u>\$ 239</u>
Common shareholders earnings				
Basic				
Distributed earnings to common shareholders	\$ 155	\$ 139	\$ 309	\$ 278
Undistributed earnings allocated to common shareholders	223	146	306	227
Total common shareholders earnings, basic	<u>\$ 378</u>	<u>\$ 285</u>	<u>\$ 615</u>	<u>\$ 505</u>
Diluted				
Distributed earnings to common shareholders	\$ 155	\$ 139	\$ 309	\$ 278
Undistributed earnings allocated to common shareholders	223	146	306	227
Total common shareholders earnings, diluted	<u>\$ 378</u>	<u>\$ 285</u>	<u>\$ 615</u>	<u>\$ 505</u>
Weighted average common shares outstanding, basic	368	356	366	355
9.50% Convertible Subordinated Notes	17	19	17	19
Weighted average common shares outstanding and participating securities, basic	<u>385</u>	<u>375</u>	<u>383</u>	<u>374</u>
Weighted average common shares outstanding, basic	368	356	366	355
Employee share-based compensation	1	1	1	1
Weighted average common shares outstanding, diluted	369	357	367	356
9.50% Convertible Subordinated Notes	17	19	17	19
Weighted average common shares outstanding and participating securities, diluted	<u>386</u>	<u>376</u>	<u>384</u>	<u>375</u>
Net earnings per common share, basic				
Distributed earnings, basic ⁽¹⁾	\$ 0.42	\$ 0.39	\$ 0.84	\$ 0.78
Undistributed earnings, basic	0.61	0.41	0.84	0.64
Total	<u>\$ 1.03</u>	<u>\$ 0.80</u>	<u>\$ 1.68</u>	<u>\$ 1.42</u>
Net earnings per common share, diluted				
Distributed earnings, diluted	\$ 0.42	\$ 0.39	\$ 0.84	\$ 0.78
Undistributed earnings, diluted	0.60	0.41	0.83	0.64
Total	<u>\$ 1.02</u>	<u>\$ 0.80</u>	<u>\$ 1.67</u>	<u>\$ 1.42</u>

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

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Peter A. Darbee, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarter ended June 30, 2009 of PG&E Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
 - a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 5, 2009

PETER A. DARBEE

Peter A. Darbee

Chairman, Chief Executive Officer, and President

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Kent M. Harvey, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarter ended June 30, 2009 of PG&E Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
 - a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 5, 2009

KENT M. HARVEY

Kent M. Harvey

Senior Vice President and Chief Financial Officer

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Christopher P. Johns, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarter ended June 30, 2009 of Pacific Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
 - a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 5, 2009

CHRISTOPHER P. JOHNS

Christopher P. Johns
President

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Barbara L. Barcon, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarter ended June 30, 2009 of Pacific Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
 - a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 5, 2009

BARBARA L. BARCON

Barbara L. Barcon

Vice President, Finance and Chief Financial Officer

**CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Quarterly Report on Form 10-Q of PG&E Corporation for the quarter ended June 30, 2009 ("Form 10-Q"), I, Peter A. Darbee, Chairman, Chief Executive Officer, and President of PG&E Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

- (1) the Form 10-Q fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) the information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

PETER A. DARBEE

PETER A. DARBEE

Chairman, Chief Executive Officer, and President

August 5, 2009

**CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Quarterly Report on Form 10-Q of PG&E Corporation for the quarter ended June 30, 2009 ("Form 10-Q"), I, Kent M. Harvey, Senior Vice President and Chief Financial Officer of PG&E Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

- (1) the Form 10-Q fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) the information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

KENT. M. HARVEY

KENT M. HARVEY

Senior Vice President and Chief Financial Officer

August 5, 2009

**CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Quarterly Report on Form 10-Q of Pacific Gas and Electric Company for the quarter ended June 30, 2009 ("Form 10-Q"), I, Christopher P. Johns, President of Pacific Gas and Electric Company, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

- (1) the Form 10-Q fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) the information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

CHRISTOPHER P. JOHNS

CHRISTOPHER P. JOHNS
President

August 5, 2009

**CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Quarterly Report on Form 10-Q of Pacific Gas and Electric Company for the quarter ended June 30, 2009 ("Form 10-Q"), I, Barbara L. Barcon, Vice President, Finance and Chief Financial Officer of Pacific Gas and Electric Company, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

- (1) the Form 10-Q fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) the information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

BARBARA L. BARCON

BARBARA L. BARCON

Vice President, Finance and Chief Financial Officer

August 5, 2009