

PG&E CORP

FORM 10-Q (Quarterly Report)

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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 March 31, 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
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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) has 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

* The registrant has not yet been phased into the interactive data requirements

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 May 1, 2009:

PG&E Corporation	368,363,541
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 MARCH 31, 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	
	March 31,	
	2009	2008
Operating Revenues		
Electric	\$ 2,426	\$ 2,514
Natural gas	1,005	1,219
Total operating revenues	3,431	3,733
Operating Expenses		
Cost of electricity	883	1,027
Cost of natural gas	557	775
Operating and maintenance	1,059	1,036
Depreciation, amortization, and decommissioning	419	402
Total operating expenses	2,918	3,240
Operating Income	513	493
Interest income	9	26
Interest expense	(181)	(187)
Other income, net	18	5
Income Before Income Taxes	359	337
Income tax provision	115	110
Net Income	244	227
Preferred dividend requirement of subsidiary	3	3
Income Available for Common Shareholders	\$ 241	\$ 224
Weighted Average Common Shares Outstanding, Basic	364	355
Weighted Average Common Shares Outstanding, Diluted	366	356
Net Earnings Per Common Share, Basic	\$ 0.65	\$ 0.62
Net Earnings Per Common Share, Diluted	\$ 0.65	\$ 0.62
Dividends Declared Per Common Share	\$ 0.42	\$ 0.39

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions)	(Unaudited)	
	Balance At	
	March 31, 2009	December 31, 2008
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 271	\$ 219
Restricted cash	1,284	1,290
Accounts receivable:		
Customers (net of allowance for doubtful accounts of \$87 million in 2009 and \$76 million in 2008)	1,490	1,751
Accrued unbilled revenue	645	685
Regulatory balancing accounts	1,372	1,197
Inventories:		
Gas stored underground and fuel oil	62	232
Materials and supplies	195	191
Income taxes receivable	45	120
Prepaid expenses and other	833	718
Total current assets	6,197	6,403
Property, Plant, and Equipment		
Electric	28,730	27,638
Gas	10,241	10,155
Construction work in progress	1,644	2,023
Other	17	17
Total property, plant, and equipment	40,632	39,833
Accumulated depreciation	(13,709)	(13,572)
Net property, plant, and equipment	26,923	26,261
Other Noncurrent Assets		
Regulatory assets	6,087	5,996
Nuclear decommissioning funds	1,634	1,718
Other	494	482
Total other noncurrent assets	8,215	8,196
TOTAL ASSETS	\$ 41,335	\$ 40,860

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited)	
	Balance At	
	March 31,	December
(in millions, except share amounts)	2009	31, 2008
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term borrowings	\$ 385	\$ 287
Long-term debt, classified as current	-	600
Energy recovery bonds, classified as current	374	370
Accounts payable:		
Trade creditors	839	1,096
Disputed claims and customer refunds	1,552	1,580
Regulatory balancing accounts	727	730
Other	408	343
Interest payable	778	802
Income taxes payable	134	-
Deferred income taxes	389	251
Other	1,364	1,567
Total current liabilities	6,950	7,626
Noncurrent Liabilities		
Long-term debt	10,185	9,321
Energy recovery bonds	1,120	1,213
Regulatory liabilities	3,770	3,657
Pension and other postretirement benefits	2,133	2,088
Asset retirement obligations	1,530	1,684
Income taxes payable	36	35
Deferred income taxes	3,496	3,397
Deferred tax credits	92	94
Other	2,161	2,116
Total noncurrent liabilities	24,523	23,605
Commitments and Contingencies		
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 366,336,769 common and 683,656 restricted shares in 2009 and issued 361,059,116 common and 1,287,569 restricted shares in 2008	6,123	5,984
Reinvested earnings	3,701	3,614
Accumulated other comprehensive loss	(214)	(221)
Total shareholders' equity	9,610	9,377
Noncontrolling Interest – Preferred Stock of Subsidiary	252	252
Total equity	9,862	9,629
TOTAL LIABILITIES AND EQUITY	\$ 41,335	\$ 40,860

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)	(Unaudited)	
	Three Months Ended	
	March 31,	
	2009	2008
Cash Flows from Operating Activities		
Net income	\$ 244	\$ 227
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	463	437
Allowance for equity funds used during construction	(25)	(20)
Deferred income taxes and tax credits, net	235	167
Other changes in noncurrent assets and liabilities	(51)	111
Effect of changes in operating assets and liabilities:		
Accounts receivable	301	89
Inventories	166	107
Accounts payable	(116)	144
Income taxes receivable/payable	209	(37)
Regulatory balancing accounts, net	(180)	(356)
Other current assets	32	103
Other current liabilities	(390)	68
Other	2	(2)
Net cash provided by operating activities	890	1,038
Cash Flows from Investing Activities		
Capital expenditures	(1,079)	(853)
Proceeds from sale of assets	2	6
Decrease in restricted cash	11	2
Proceeds from nuclear decommissioning trust sales	387	164
Purchases of nuclear decommissioning trust investments	(412)	(117)
Other	5	-
Net cash used in investing activities	(1,086)	(798)
Cash Flows from Financing Activities		
Net repayments under revolving credit facility	-	(250)
Net issuance (repayments) of commercial paper, net of discount of \$2 million in 2009 and \$1 million in 2008	96	(198)
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)	(300)
Energy recovery bonds matured	(89)	(83)
Common stock issued	96	39
Common stock dividends paid	(138)	(129)
Other	(1)	(9)
Net cash provided by (used in) financing activities	248	(332)
Net change in cash and cash equivalents	52	(92)
Cash and cash equivalents at January 1	219	345
Cash and cash equivalents at March 31	\$ 271	\$ 253
Supplemental disclosures of cash flow information		
Cash (paid) received for:		
Interest, net of amounts capitalized	\$ (190)	\$ (189)
Income taxes, net	294	-
Supplemental disclosures of noncash investing and financing activities		
Common stock dividends declared but not yet paid	\$ 154	\$ 139
Capital expenditures financed through accounts payable	235	242
Noncash common stock issuances	33	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	
	March 31,	
	2009	2008
Operating Revenues		
Electric	\$ 2,426	\$ 2,514
Natural gas	1,005	1,219
Total operating revenues	3,431	3,733
Operating Expenses		
Cost of electricity	883	1,027
Cost of natural gas	557	775
Operating and maintenance	1,059	1,036
Depreciation, amortization, and decommissioning	419	402
Total operating expenses	2,918	3,240
Operating Income	513	493
Interest income	9	24
Interest expense	(173)	(180)
Other income, net	21	19
Income Before Income Taxes	370	356
Income tax provision	131	120
Net Income	239	236
Preferred dividend requirement	3	3
Income Available for Common Shareholders	\$ 236	\$ 233

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited)	
	Balance At	
	March 31,	December
(in millions)	2009	31, 2008
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 54	\$ 52
Restricted cash	1,284	1,290
Accounts receivable:		
Customers (net of allowance for doubtful accounts of \$87 million in 2009 and \$76 million in 2008)	1,490	1,751
Accrued unbilled revenue	645	685
Related parties	5	2
Regulatory balancing accounts	1,372	1,197
Inventories:		
Gas stored underground and fuel oil	62	232
Materials and supplies	195	191
Income taxes receivable	21	25
Prepaid expenses and other	823	705
Total current assets	5,951	6,130
Property, Plant, and Equipment		
Electric	28,730	27,638
Gas	10,241	10,155
Construction work in progress	1,644	2,023
Total property, plant, and equipment	40,615	39,816
Accumulated depreciation	(13,693)	(13,557)
Net property, plant, and equipment	26,922	26,259
Other Noncurrent Assets		
Regulatory assets	6,087	5,996
Nuclear decommissioning funds	1,634	1,718
Related parties receivable	26	27
Other	423	407
Total other noncurrent assets	8,170	8,148
TOTAL ASSETS	\$ 41,043	\$ 40,537

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)	(Unaudited)	
	Balance At	
	March 31, 2009	December 31, 2008
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	\$ 385	\$ 287
Long-term debt, classified as current	-	600
Energy recovery bonds, classified as current	374	370
Accounts payable:		
Trade creditors	839	1,096
Disputed claims and customer refunds	1,552	1,580
Related parties	19	25
Regulatory balancing accounts	727	730
Other	405	325
Interest payable	771	802
Income tax payable	144	53
Deferred income taxes	396	257
Other	1,169	1,371
Total current liabilities	6,781	7,496
Noncurrent Liabilities		
Long-term debt	9,585	9,041
Energy recovery bonds	1,120	1,213
Regulatory liabilities	3,770	3,657
Pension and other postretirement benefits	2,084	2,040
Asset retirement obligations	1,530	1,684
Income taxes payable	12	12
Deferred income taxes	3,546	3,449
Deferred tax credits	92	94
Other	2,119	2,064
Total noncurrent liabilities	23,858	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	2,861	2,331
Reinvested earnings	6,172	6,092
Accumulated other comprehensive loss	(209)	(216)
Total shareholders' equity	10,404	9,787
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	\$ 41,043	\$ 40,537

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	(Unaudited)	
	Three Months Ended March 31,	
	2009	2008
(in millions)		
Cash Flows from Operating Activities		
Net income	\$ 239	\$ 236
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	456	437
Allowance for equity funds used during construction	(25)	(20)
Deferred income taxes and tax credits, net	234	160
Other changes in noncurrent assets and liabilities	(48)	106
Effect of changes in operating assets and liabilities:		
Accounts receivable	298	88
Inventories	166	107
Accounts payable	(107)	149
Income taxes receivable/payable	95	(20)
Regulatory balancing accounts, net	(180)	(356)
Other current assets	34	104
Other current liabilities	(386)	65
Other	1	(2)
Net cash provided by operating activities	777	1,054
Cash Flows from Investing Activities		
Capital expenditures	(1,079)	(853)
Proceeds from sale of assets	2	6
Decrease in restricted cash	11	2
Proceeds from nuclear decommissioning trust sales	387	164
Purchases of nuclear decommissioning trust investments	(412)	(117)
Net cash used in investing activities	(1,091)	(798)
Cash Flows from Financing Activities		
Net repayments under revolving credit facility	-	(250)
Net issuance (repayments) of commercial paper, net of discount of \$2 million in 2009 and \$1 million in 2008	96	(198)
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)	(300)
Energy recovery bonds matured	(89)	(83)
Preferred stock dividends paid	(3)	(3)
Common stock dividends paid	(156)	(142)
Equity contribution	528	50
Other	2	(7)
Net cash provided by (used in) financing activities	316	(335)
Net change in cash and cash equivalents	2	(79)
Cash and cash equivalents at January 1	52	141
Cash and cash equivalents at March 31	\$ 54	\$ 62
Supplemental disclosures of cash flow information		
Cash (paid) received for:		
Interest, net of amounts capitalized	\$ (190)	\$ (189)
Income taxes, net	163	-
Supplemental disclosures of noncash investing and financing activities		
Capital expenditures financed through accounts payable	\$ 235	\$ 242

See accompanying Notes to the Condensed Consolidated Financial Statements.

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 primarily regulated 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.”

Except for the new and significant accounting policies described in Note 2 below, 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.

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

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

In March 2008, the Financial Accounting Standards Board (“FASB”) issued 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. SFAS No. 161 is effective prospectively for fiscal years beginning after November 15, 2008. (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.

As of March 31, 2009 and December 31, 2008, PG&E Corporation’s \$252 million preferred stock of subsidiary represents a noncontrolling interest in the Utility. PG&E Corporation has reclassified the noncontrolling interest 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 March 31, 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, the adoption of SFAS No. 160 had no material impact on PG&E Corporation’s and the Utility’s Condensed Consolidated Financial Statements.

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

In September 2008, the FASB issued 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. EITF 08-5 is effective prospectively for fiscal years beginning on or after December 15, 2008 and interim periods within those fiscal years. EITF 08-5 did not have a material impact on PG&E Corporation’s and the Utility’s Condensed Consolidated Financial Statements.

Equity Method Investment Accounting Consideration — an amendment to Accounting Principles Board No. 18

In November 2008, the FASB issued 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(R), “Business Combinations.” However, the investor of 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. EITF 08-6 is effective prospectively for fiscal years beginning on or after December 15, 2008 and interim periods within those fiscal years. Adoption of EITF 08-6 did not have a material impact on PG&E Corporation’s or the Utility’s Condensed Consolidated Financial Statements.

Consolidation of Variable Interest Entities

FASB Interpretation No. 46 (revised December 2003), “Consolidation of Variable Interest Entities” (“FIN 46R”), provides that an entity is a variable interest entity (“VIE”) if it does not have sufficient equity investment at risk or if the holders of the entity’s equity instruments lack the essential characteristics of a controlling financial interest. FIN 46R requires that the holder subject to the majority of the risk of loss from a VIE’s activities must consolidate the VIE. However, if no holder has the majority of the risk of loss, then a holder entitled to receive a majority of the entity’s residual returns would consolidate the entity.

The majority of the Utility’s involvement with VIEs is through power purchase agreements. The Utility could have a significant variable interest in a power purchase agreement counterparty if that entity is a VIE owning one or more plants that sell substantially all of their output to the Utility. The Utility performs a qualitative assessment of power purchase agreements under FIN 46R, comparing the term of the contract to the remaining useful life of the plant to determine its absorption of the expected risks and rewards of the project, including production risk, commodity price risk, credit risk, and tax attributes.

At December 31, 2008, the Utility held a significant variable interest in one VIE. (See Note 2 of the Notes to the Consolidated Financial Statements in the 2008 Annual Report.) Additionally, during February 2009, the CPUC approved an agreement for the Utility to purchase as-available electric generation output from an approximately 250 megawatt (“MW”) solar photovoltaic facility for 25 years, beginning from the date of commercial operation. The 250 MW solar photovoltaic facility is a subsidiary of a publicly held company, and its activities are financed primarily through equity from investors and proceeds from non-recourse project-specific debt financing. The solar photovoltaic facility is a VIE and the Utility holds a significant variable interest through the power purchase agreement. Activities of the VIE consist of renewable energy production from a single facility for sale to third parties, and the facility is expected to become operational in 2012. The Utility is not considered the primary beneficiary of the VIE, as it will not absorb the majority of the VIE’s expected losses or residual returns. Accordingly, the Utility has not consolidated this VIE in its Condensed Consolidated Financial Statements. No payments for energy have been made to either VIE as of March 31, 2009.

These power purchase agreements do not expose the Utility to amounts in excess of the payments for as-available electricity. Future payments to these facilities are made based on the energy produced and are expected to be recoverable through customer rates. Additionally, no financial or other support was provided by the Utility to these VIEs as of March 31, 2009.

Share-Based Compensation

The following table provides a summary of total compensation expense for PG&E Corporation and the Utility for share-based incentive awards for the three months ended March 31, 2009 and 2008:

(in millions)	PG&E Corporation		Utility	
	Three Months Ended		Three Months Ended	
	March 31,		March 31,	
	2009	2008	2009	2008
Stock options	\$ -	\$ 1	\$ -	\$ 1
Restricted stock	2	9	2	5
Restricted stock units ⁽¹⁾	6	-	3	-
Performance shares	16	(4)	10	(3)
Total compensation expense (pre-tax)	\$ 24	\$ 6	\$ 15	\$ 3
Total compensation expense (after-tax)	\$ 14	\$ 4	\$ 9	\$ 2

⁽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, and the remaining 40% will vest 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 months ended March 31, 2009 and 2008 are as follows:

(in millions)	Pension Benefits		Other Benefits	
	Three Months Ended		Three Months Ended	
	March 31,		March 31,	
	2009	2008	2009	2008
Service cost for benefits earned	\$ 66	\$ 59	\$ 8	\$ 7
Interest cost	155	144	21	20
Expected return on plan assets	(145)	(175)	(17)	(24)
Amortization of transition obligation ⁽¹⁾	-	-	6	7
Amortization of prior service cost ⁽¹⁾	11	12	4	4
Amortization of unrecognized (gain) loss ⁽¹⁾	25	-	1	(4)
Net periodic benefit cost	\$ 112	\$ 40	\$ 23	\$ 10
Less: transfer to regulatory account ⁽²⁾	(71)	1	-	-
Total	\$ 41	\$ 41	\$ 23	\$ 10

⁽¹⁾ In 2009 and 2008, under SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)," PG&E Corporation and the Utility recorded amounts related to pension and other benefits in other comprehensive income, net of related deferred taxes, except for a portion recorded as a regulatory asset in 2009 and regulatory liability in 2008 in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," as amended ("SFAS No. 71").

⁽²⁾ Under SFAS No. 71, the Utility recorded approximately \$71 million in 2009 as an addition to the existing pension regulatory asset and approximately \$1 million in 2008 as an addition to the existing pension regulatory liability to reflect the difference between pension expense or income for accounting purposes and pension expense or income for ratemaking, 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 months ended March 31, 2009.

Accounting Pronouncements Issued But Not Yet Adopted

Disclosures about Employers' Postretirement Benefit Plan Assets — an amendment to FASB Statement No. 132(R)

In December 2008, the FASB issued FASB Staff Position ("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, "Employers' Disclosures about Pensions and Other Postretirement Benefits." 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 fiscal years ending after December 15, 2009. PG&E Corporation and the Utility are currently evaluating the impact of FSP SFAS 132(R)-1.

Interim Disclosures about Fair Value of Financial Instruments

In April 2009, the FASB issued FSP SFAS 107-1 and APB No. 28-1, "Interim Disclosures about Fair Value of Financial Instruments" ("FSP SFAS 107-1 and APB No. 28-1"). This FSP amends SFAS No. 107 and APB 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. FSP SFAS 107-1 and APB No. 28-1 is effective prospectively for interim reporting periods after June 15, 2009. PG&E Corporation and the Utility are currently evaluating the impact of FSP SFAS 107-1 and APB No. 28-1.

Recognition and Presentation of Other-Than-Temporary Impairments

In April 2009, the FASB issued FSP SFAS 115-2 and SFAS 124-2, "Recognition and Presentation of Other-Than-Temporary Impairments" ("FSP SFAS 115-2 and SFAS 124-2"). This FSP amends existing guidance related to other-than-temporary impairments to improve disclosure of other-than-temporary impairments on debt and equity securities in the financial statements. Recognition and measurement guidance is not amended by this FSP. FSP SFAS 115-2 and SFAS 124-2 is effective prospectively for interim reporting periods after June 15, 2009. PG&E Corporation and the Utility are currently evaluating the impact of FSP SFAS 115-2 and SFAS 124-2.

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

In April 2009, the FASB issued 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 volume or level of activity for an asset or liability has significantly decreased when compared with normal market conditions. Guidance to identify circumstances when a transaction is not orderly, or is distressed or forced, is also provided. FSP SFAS 157-4 is effective prospectively for interim reporting periods after June 15, 2009. PG&E Corporation and the Utility are currently evaluating the impact of FSP SFAS 157-4.

NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

The Utility accounts for the financial effects of regulation in accordance with SFAS No. 71. SFAS No. 71 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.

Regulatory Assets

Long-Term Regulatory Assets

Long-term regulatory assets are composed of the following:

(in millions)	Balance At	
	March 31, 2009	December 31, 2008
Pension benefits	\$ 1,660	\$ 1,624
Energy recovery bonds	1,406	1,487
Deferred income tax	880	847
Utility retained generation	780	799
Price risk management	511	362
Environmental compliance costs	375	385
Unamortized loss, net of gain, on reacquired debt	219	225
Regulatory assets associated with plan of reorganization	90	99
Contract termination costs	78	82
Other	88	86
Total regulatory assets	\$ 6,087	\$ 5,996

See Note 3 of the Notes to the Consolidated Financial Statements in the 2008 Annual Report for further discussion of the long-term regulatory assets.

Current Regulatory Assets

At March 31, 2009 and December 31, 2008, the Utility had current regulatory assets of approximately \$612 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. 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	
	March 31, 2009	December 31, 2008
Cost of removal obligation	\$ 2,805	\$ 2,735
Public purpose programs	307	259
Recoveries in excess of asset retirement obligation	271	226
California Solar Initiative	180	183
Price risk management	82	81
Gateway Generating Station	66	67
Environmental remediation insurance recoveries	41	52
Other	18	54
Total regulatory liabilities	\$ 3,770	\$ 3,657

See Note 3 of the Notes to the Consolidated Financial Statements in the 2008 Annual Report for further discussion of the long-term regulatory liabilities.

Current Regulatory Liabilities

As of March 31, 2009 and December 31, 2008, the Utility had current regulatory liabilities of approximately \$263 million and \$313 million, respectively, primarily consisting of 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 revenue 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 cost 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 Utility's current regulatory balancing accounts accumulate balances until they are 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. The CPUC does not allow the Utility to offset regulatory balancing account assets against regulatory balancing account liabilities.

Current Regulatory Balancing Accounts

(in millions)	Receivable (Payable) Balance At	
	March 31, 2009	December 31, 2008
Utility generation	\$ 444	\$ 164
Modified transition cost	227	214
Energy resource recovery	200	384
Distribution revenue adjustment mechanism	185	40
Transmission revenue	170	173
Gas purchase and distribution	(126)	(8)
Public purpose programs	(231)	(263)
Energy recovery bonds	(219)	(231)
Other	(5)	(6)
Total regulatory balancing accounts, net	\$ 645	\$ 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. Because the Utility's recovery of these revenue requirements is independent, or "decoupled," from the volume of sales, 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. During the summer months, the under-collection generally decreases as the volume of electricity sales increases with warmer weather.

The modified transition cost balancing account is used to track the recovery of ongoing competition transition charge ("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 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 and recoveries of 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 distribution revenue adjustment mechanism account is used to record and recover the authorized electric distribution revenue requirements and certain other electric distribution-related authorized costs. Because the Utility's recovery of these revenue requirements is independent, or "decoupled," from the volume of sales, 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. During the summer months, the under-collection generally decreases as the volume of electricity sales increases with warmer weather.

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 gas purchase and distribution balancing accounts track actual gas costs and recoveries, as well as the difference between the authorized and recovered gas base revenue requirement, which is intended to recover the portions of operation and maintenance expenses, depreciation, taxes, and return on invested capital that are associated with small commercial and residential (or "core") customers.

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 approximately \$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 ("ERBs") 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 March 31, 2009 and December 31, 2008, "Other" consisted of various miscellaneous balancing accounts.

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 March 31, 2009, PG&E Corporation had a \$200 million revolving credit facility, which included a commitment from Lehman Brothers Bank, FSB (“Lehman Bank”) that represented approximately \$13 million, or 7%, of the total borrowing capacity under the revolving credit facility. On April 27, 2009, PG&E Corporation amended the revolving credit facility and removed Lehman Bank as a lender. As a result, total borrowing capacity under PG&E Corporation’s revolving credit facility is now \$187 million.

Utility

Senior Notes

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

Credit Facility and Short-Term Borrowings

At March 31, 2009, the Utility had approximately \$295 million of letters of credit outstanding under the Utility’s \$2.0 billion revolving credit facility. The commitment from Lehman Bank represented approximately \$60 million, or 3%, of the total borrowing capacity under the revolving credit facility. On April 27, 2009, the Utility amended the revolving credit facility and removed Lehman Bank as a lender. As a result, total borrowing capacity under the Utility’s revolving credit facility is now \$1.94 billion.

In addition, the revolving credit facility provides liquidity support for commercial paper offerings. At March 31, 2009, the Utility had \$385 million of commercial paper outstanding at an average yield of approximately 1.15%.

Energy 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 \$1.5 billion at March 31, 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 three months ended March 31, 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	244	239
Common stock issued	129	-
Share-based compensation amortization	8	-
Common stock dividends declared and paid	-	(156)
Common stock dividends declared but not yet paid	(154)	-
Preferred dividend requirement	-	(3)
Preferred dividend requirement of subsidiary	(3)	-
Tax benefit from employee stock plans	2	2
Other comprehensive income	7	7
Equity contribution	-	528
Balance at March 31, 2009	\$ 9,862	\$ 10,404

For the three months ended March 31, 2009, PG&E Corporation contributed equity of \$528 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 three months ended March 31, 2009, the Utility paid common stock dividends totaling \$156 million to PG&E Corporation.

During the three months ended March 31, 2009, PG&E Corporation paid common stock dividends totaling \$143 million. On February 18, 2009, the Board of Directors of PG&E Corporation declared a dividend of \$0.42 per share, totaling \$154 million, which was paid on April 15, 2009 to shareholders of record on March 31, 2009.

During the three months ended March 31, 2009, the Utility paid cash dividends to holders of its outstanding series of preferred stock totaling \$3 million. On February 18, 2009, the Board of Directors of the Utility declared a cash dividend, totaling \$3 million, on its outstanding series of preferred stock, payable on May 15, 2009 to shareholders of record on April 30, 2009.

NOTE 6: EARNINGS PER COMMON 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 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 March 31,	
	2009	2008
Income Available for Common Shareholders	\$ 241	\$ 224
Less: distributed earnings to common shareholders	154	139
Undistributed earnings	<u>\$ 87</u>	<u>\$ 85</u>
Common shareholders earnings		
<i>Basic</i>		
Distributed earnings to common shareholders	\$ 154	\$ 139
Undistributed earnings allocated to common shareholders	83	81
Total common shareholders earnings, basic	<u>\$ 237</u>	<u>\$ 220</u>
<i>Diluted</i>		
Distributed earnings to common shareholders	\$ 154	\$ 139
Undistributed earnings allocated to common shareholders	83	81
Total common shareholders earnings, diluted	<u>\$ 237</u>	<u>\$ 220</u>
Weighted average common shares outstanding, basic	364	355
9.50% Convertible Subordinated Notes	17	19
Weighted average common shares outstanding and participating securities, basic	<u>381</u>	<u>374</u>
Weighted average common shares outstanding, basic	364	355
Employee share-based compensation	2	1
Weighted average common shares outstanding, diluted	366	356
9.50% Convertible Subordinated Notes	17	19
Weighted average common shares outstanding and participating securities, diluted	<u>383</u>	<u>375</u>
Net earnings per common share, basic		
Distributed earnings, basic ⁽¹⁾	\$ 0.42	\$ 0.39
Undistributed earnings, basic	0.23	0.23
Total	<u>\$ 0.65</u>	<u>\$ 0.62</u>
Net earnings per common share, diluted		
Distributed earnings, diluted	\$ 0.42	\$ 0.39
Undistributed earnings, diluted	0.23	0.23
Total	<u>\$ 0.65</u>	<u>\$ 0.62</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 26,592 and 7,285 shares of PG&E Corporation common stock were excluded from the computation of diluted EPS for the three months ended March 31, 2009 and 2008, respectively, because the exercise prices of these options were greater than the average market price of PG&E Corporation common stock during these periods.

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.

Additionally, in order to fund its business operations, PG&E Corporation issued 9.50% Convertible Subordinated Notes with an outstanding value of approximately \$252 million at March 31, 2009. The notes are scheduled to mature on June 30, 2010. These Convertible Subordinated Notes may be converted (at the option of the holder) at any time prior to maturity into 16,702,194 shares of PG&E Corporation common stock, at a conversion price of \$15.09 per share. The conversion price is subject to adjustment for significant changes in the number of outstanding shares of PG&E Corporation's common stock. In addition, holders of the PG&E Corporation Convertible Subordinated Notes have the right 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 price. In accordance with SFAS No. 133, the dividend participation rights of 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.

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 commodity-related price risk-related derivative instruments 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 both physical and financial risk associated with transmission congestion.

Under FERC rules, the CAISO was required to make long-term firm transmission rights ("FTRs") available by auction to the California investor-owned utilities and other load-serving entities to allow these entities to hedge both the physical transmission risk by providing scheduling priority on the transmission lines and the financial risk associated with CAISO-imposed congestion charges. The use of FTRs was discontinued on April 1, 2009 when the CAISO implemented its new day-ahead wholesale electricity market as part of its Market Redesign and Technology Update ("MRTU"). In lieu of FTRs, 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). The Utility acquired CRRs in 2008 (via allocation and auction) in anticipation of the effectiveness of the MRTU. In the first quarter of 2009, the Utility acquired additional CRRs through both allocation and auction. Also, in the first quarter of 2009, the Utility acquired additional FTRs through auction in order to hedge its physical and financial risk until the MRTU became effective on April 1, 2009.

CRRs and FTRs are considered derivative instruments and are recorded at fair value within the Condensed Consolidated Balance Sheets. FTRs are recorded at zero value on the Condensed Consolidated Balance Sheets, reflecting the nullification of FTRs on March 31, 2009.

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 (Core Customers)

The Utility enters into physical natural gas commodity contracts to fulfill the needs of its retail 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 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

The dividend participation rights of the Convertible Subordinated Notes are considered embedded derivative instruments in accordance with the provisions of SFAS No. 133. Therefore, these rights are bifurcated from the Convertible Subordinated Notes and are recorded at fair value in PG&E Corporation's Condensed Consolidated Financial Statements. Changes in the fair value are recognized in PG&E Corporation's Condensed Consolidated Statements of Income as a non-operating expense or income (in Other income, net). Since January 1, 2009, PG&E Corporation has paid pass-through dividends totaling approximately \$14 million, including \$7 million paid on April 15, 2009.

Volume of Derivative Activity

As of March 31, 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	336,621,564	161,031,167	20,600,000	-
	Options	156,232,065	138,070,000	20,600,000	-
Electricity (Megawatt-hours)	Forwards, Futures, and Swaps	6,882,548	7,358,609	5,996,652	6,666,744
	Options	19,392	10,408	10,464	11,200
	Congestion Revenue Rights	65,020,816	59,670,412	59,604,520	124,349,006
PG&E Corporation Equity Shares	Dividend Participation Rights	16,702,194	16,702,904	-	-

⁽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 FASB Staff Position on FASB Interpretation 39, "Amendment of FASB Interpretation No. 39" ("FIN 39-1"), which was adopted January 1, 2008, the net balances include outstanding cash collateral associated with derivative positions.

As of March 31, 2009, PG&E Corporation's and the Utility's outstanding derivative balances were as follows:

(in millions)	Gross Balances ⁽¹⁾					Cash Collateral ⁽³⁾	Total Derivative Balances on the Condensed Consolidated Balance Sheets
	Derivatives Designated as Cash Flow Hedges ⁽²⁾	Derivatives Not Designated as Hedges	Total	Netting ⁽³⁾			
	Commodity Risk (Corporation and Utility)						
Current Assets – Prepaid expenses and other	\$ -	\$ 62	\$ 62	\$ (10)	\$ 83	\$ 135	
Other Noncurrent Assets – Other	-	107	107	(25)	81	163	
Current Liabilities – Other	(138)	(299)	(437)	10	278	(149)	
Noncurrent Liabilities – Other	(229)	(306)	(535)	25	150	(360)	
Total Commodity Risk	\$ (367)	\$ (436)	\$ (803)	\$ -	\$ 592	\$ (211)	
Other Risk Instruments ⁽⁴⁾ (PG&E Corporation Only)							
Current Liabilities –Other	\$ -	\$ (26)	\$ (26)	\$ -	\$ -	\$ (26)	
Noncurrent Liabilities – Other	-	(7)	(7)	-	-	(7)	
Total Other Risk Instruments	\$ -	\$ (33)	\$ (33)	\$ -	\$ -	\$ (33)	
Total Derivatives	\$ (367)	\$ (469)	\$ (836)	\$ -	\$ 592	\$ (244)	

⁽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 March 31, 2009, PG&E Corporation and the Utility had cash flow hedges with expiration dates through December 2012 for energy contract-related derivative instruments.

⁽³⁾ Netting in accordance with FIN 39 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 three-month period ended March 31, 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)			
Regulatory assets and liabilities ⁽²⁾	\$ 16	\$ (323)	\$ (307)
Cost of electricity ⁽³⁾	23	179	202
Cost of natural gas ⁽³⁾	23	-	23
Total Commodity Risk	\$ 62	\$ (144)	\$ (82)
Other Risk Instruments (PG&E Corporation Only)			
Other income, net	\$ -	\$ 2	\$ 2
Total Other Risk	\$ -	\$ 2	\$ 2

⁽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 Condensed Consolidated Income Statement. 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.

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.

As of March 31, 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)	As of March 31, 2009
Derivatives in a Liability Position with Credit-Risk-Related Contingencies That Are Not Fully Collateralized	\$ (652)
Related Derivatives in an Asset Position	5
Collateral Posting in the Normal Course of Business Related to These Derivatives	161
Net Position of Derivative Contracts/Additional Collateral Posting Requirements ⁽¹⁾	\$ (486)

⁽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 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 as of March 31, 2009. The instruments are classified based on the lowest level of input that is significant to the fair value measurement. 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 as of March 31, 2009				
(in millions)	Level 1	Level 2	Level 3	Total
Assets:				
Money market investments (held by PG&E Corporation)	\$ 211	\$ -	\$ 8	\$ 219
Nuclear decommissioning trusts ⁽¹⁾	1,455	249	4	1,708
Rabbi trusts	59	-	-	59
Long-term disability trust	86	-	71	157
Assets Total	\$ 1,811	\$ 249	\$ 83	\$ 2,143
Liabilities:				
Dividend participation rights	\$ -	\$ -	\$ 33	\$ 33
Price risk management instruments ⁽²⁾	(51)	86	176	211
Other	-	-	1	1
Liabilities Total	\$ (51)	\$ 86	\$ 210	\$ 245

⁽¹⁾ Excludes taxes on appreciation of investment value.

⁽²⁾ Balances include the impact of netting adjustments in accordance with the requirements of FIN 39-1 of \$229 million to Level 1, \$123 million to Level 2, and \$240 million to Level 3.

Utility				
Fair Value Measurements as of March 31, 2009				
(in millions)	Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trusts ⁽¹⁾	\$ 1,455	\$ 249	\$ 4	\$ 1,708
Long-term disability trust	86	-	71	157
Assets Total	\$ 1,541	\$ 249	\$ 75	\$ 1,865
Liabilities:				
Price risk management instruments ⁽²⁾	\$ (51)	\$ 86	\$ 176	\$ 211
Other	-	-	1	1
Liabilities Total	\$ (51)	\$ 86	\$ 177	\$ 212

⁽¹⁾ Excludes taxes on appreciation of investment value.

⁽²⁾ Balances include the impact of netting adjustments in accordance with the requirements of FIN 39-1 of \$229 million to Level 1, \$123 million to Level 2, and \$240 million to Level 3.

PG&E Corporation's and the Utility's fair value measurements incorporate various factors required under SFAS No. 157, such as nonperformance and credit risk adjustments. As of March 31, 2009, the nonperformance and credit risk adjustment represented approximately 3% of the net price risk management value. As permitted under SFAS No. 157, 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 as of March 31, 2009 and December 31, 2008.
- The fair values of the Utility's fixed rate senior notes, fixed rate pollution control bond loan agreements, and the ERBs issued by PERF were based on quoted market prices obtained from the Bloomberg financial information system at March 31, 2009.
- The fair value of PG&E Corporation's 9.50% Convertible Subordinated Notes was determined by considering the prices of securities displayed as of the close of business on March 31, 2009 by a proprietary bond trading system that tracks and marks a broad universe of convertible securities, including the securities being assessed.

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 fair values that approximate their carrying values, as these instruments are presented at their carrying value in the Condensed Consolidated Balance Sheets):

(in millions)	At March 31, 2009		At December 31, 2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Debt (Note 4):				
PG&E Corporation	\$ 602	\$ 1,002	\$ 280	\$ 739
Utility	8,690	8,820	8,740	9,134
Energy recovery bonds (Note 4)	1,494	1,526	1,583	1,564

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 three-month period ended March 31, 2009:

(in millions)	PG&E Corporation Only		PG&E Corporation and the Utility				
	Money Market Instruments	Dividend Participation Rights	Price Risk Management Instruments	Nuclear Decommissioning Trusts ⁽¹⁾	Long- term Disability	Other	Total
Asset (liability)							
Balance as of							
January 1, 2009	\$ 12	\$ (42)	\$ (156)	\$ 5	\$ 78	\$ (2)	\$ (105)
Realized and unrealized gains (losses):							
Included in earnings	-	2	-	-	(7)	-	(5)
Included in regulatory assets and liabilities or balancing accounts	-	-	(20)	(1)	-	1	(20)
Purchases, issuances, and settlements	(4)	7	-	-	-	-	3
Transfers in to Level 3	-	-	-	-	-	-	-
Asset (liability)							
Balance as of							
March 31, 2009	\$ 8	\$ (33)	\$ (176)	\$ 4	\$ 71	\$ (1)	\$ (127)

⁽¹⁾ Excludes taxes on appreciation of investment value.

Earnings for the period were impacted by a \$5 million unrealized loss relating to assets or liabilities still held at March 31, 2009.

PG&E Corporation and the Utility did not have any nonrecurring financial measurements that are within the scope of SFAS No. 157 as

of March 31, 2009.

NOTE 9: RELATED PARTY AGREEMENTS AND TRANSACTIONS

In accordance with various agreements, the Utility and other subsidiaries provide and receive various services to and from their parent, PG&E Corporation, and among themselves. The Utility and PG&E Corporation exchange administrative and professional services in support of operations. Services provided directly to PG&E Corporation by the Utility are priced at the higher of fully loaded cost (i.e., direct cost of good or service and allocation of overhead costs) or fair market value, depending on the nature of the services. Services provided directly to the Utility by PG&E Corporation are 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)	Three Months Ended	
	March 31,	
	2009	2008
Utility revenues from:		
Administrative services provided to PG&E Corporation	\$ 1	\$ 1
Utility employee benefit due from PG&E Corporation	-	-
Utility expenses from:		
Administrative services received from PG&E Corporation	\$ 19	\$ 24
Utility employee benefit due to PG&E Corporation	6	7

At March 31, 2009 and December 31, 2008, the Utility had a receivable of approximately \$31 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 approximately \$19 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 of the U.S. Bankruptcy Code ("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 March 31, 2009:

(in millions)	
Balance at December 31, 2008	\$ 1,750
Interest accrued	20
Less: Settlements	(33)
Balance at March 31, 2009	\$ 1,737

As of March 31, 2009, the Utility's net disputed claims liability was approximately \$1,737 million, consisting of approximately \$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 \$679 million (classified on the Condensed Consolidated Balance Sheets within Interest payable) offset by accounts receivable from the CAISO and PX of approximately \$494 million (classified on the Condensed Consolidated Balance Sheets within Accounts receivable – Customers).

In connection with the Utility's proceedings under Chapter 11, the Utility established an escrow account for the payment of the disputed claims, which is included within Restricted cash on the Condensed Consolidated Balance Sheets. As of March 31, 2009, the Utility held \$1,213 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 has agreed to transfer \$700 million to the PX from the Utility's escrow established for disputed claims to enable the PX to fund future settlements, pay refund claims or amounts owed in CAISO or PX markets as may be authorized by the FERC or a court of competent jurisdiction. The proposed agreement is subject to approval by the FERC and by the bankruptcy courts that have jurisdiction over the Chapter 11 proceedings of the PX and the Utility. The Utility's payment would reduce its liability for the remaining net disputed claims. To protect the Utility against the imposition of double liability, the proposed 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 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 electric energy and capacity and makes payments under existing power purchase agreements. The price of purchased power may be fixed or variable. Variable pricing is generally based on either the current market price of gas or of electricity at the date of purchase. Forward prices as of March 31, 2009 are used to determine the undiscounted future expected payments for contracts with variable pricing terms. At March 31, 2009, the undiscounted future expected power purchase agreement payments were as follows:

(in millions)	
2009	\$ 1,576
2010	2,137
2011	2,249
2012	2,205
2013	2,098
Thereafter	21,784
Total	\$ 32,049

Payments made by the Utility under power purchase agreements amounted to approximately \$663 million and \$1,028 million for the three months ended March 31, 2009 and March 31, 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	\$ 43
2010	50
2011	50
2012	50
2013	50
Thereafter	206
Total fixed capacity payments	\$ 449
Less: Amount representing interest	105
Present value of fixed capacity payments	\$ 344

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, which allow QFs to recover investment costs, 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 March 31, 2009, the Utility's undiscounted obligations for natural gas purchases and gas transportation services were as follows:

(in millions)		
2009	\$	486
2010		300
2011		118
2012		49
2013		42
Thereafter		157
Total	\$	1,152

Payments for natural gas purchases and gas transportation services amounted to approximately \$456 million and \$797 million for the three months ended March 31, 2009 and March 31, 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 NEG-T subsidiary company. PG&E Corporation's sole remaining exposure relates to any potential environmental obligations that were known to NEG-T 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 is expected to begin 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. Although the appellant did not seek to obtain an order prohibiting the Utility from loading spent fuel, the petition stated that they may seek a stay of fuel loading at the facility. 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.

If the Utility is unable to begin loading spent nuclear fuel by October 2010 for Unit 1 or May 2011 for Unit 2 and if the Utility is otherwise unable to increase its on-site storage capacity, the Utility would have to curtail or halt operations until such time as additional safe storage for spent fuel is made available.

On August 7, 2008, the U.S. Court of Appeals for the Federal Circuit issued an appellate order in the litigation pending against the DOE in which the Utility and other nuclear power plant owners seek to recover costs that they incurred to build on-site spent nuclear fuel storage facilities due to the DOE's delay in constructing a national repository for nuclear waste. In October 2006, the U.S. Court of Federal Claims found that the DOE had breached its contract with the Utility but awarded the Utility approximately \$43 million of the \$92 million incurred by the Utility through 2004. In ruling on the Utility's appeal, the U.S. Court of Appeals for the Federal Circuit reversed the lower court on issues relating to the calculation of damages and ordered the lower court to re-calculate the award. Although various motions by the DOE for reconsideration are still pending, the judge in the lower court conducted a status conference on January 15, 2009 and has scheduled another conference for July 9, 2009. The Utility expects that the final award will be approximately \$91 million for costs incurred through 2004 and that the Utility will recover all of its costs incurred after 2004 to build on-site storage facilities. Amounts recovered from the DOE will be credited to customers through rates.

PG&E Corporation and the Utility are unable to predict the outcome of any rehearing petition.

Application to Recover Hydroelectric Facility Divestiture Costs

On April 16, 2009, the CPUC approved a decision to authorize the Utility to recover approximately \$47 million, including approximately \$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.

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. 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 December 18, 2008, based on their first interim claims, the CPUC awarded interim incentive earnings to the utilities for their 2006–2007 program performance, subject to a holdback until completion of final measurement studies and a final verification report for the entire three-year program cycle. The CPUC awarded the Utility \$41.5 million in shareholder incentive revenues, representing 35% of \$119 million estimated shareholder incentive revenues for the Utility's energy efficiency program performance in 2006–2007.

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 April 14, 2009, the CPUC issued a ruling setting forth the scope and schedule for the new rulemaking proceeding. The CPUC ordered the parties to participate in a settlement conference to begin on May 6, 2009 to resolve the utilities' interim claims for 2008 performance and the utilities' final claims for the entire 2006–2008 program period. If a settlement is not reached, the CPUC schedule calls for hearings to begin in June 2009.

Whether or not the Utility will receive any of the remaining \$77 million in incentives for the 2006 and 2007 program years, whether the Utility will receive any additional incentives or incur a reimbursement obligation in 2009 based on the second interim claim for 2008 performance, and whether the final true-up in 2010 will result in a positive or negative adjustment remain uncertain.

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 approximately \$587 million at March 31, 2009, and approximately \$568 million at December 31, 2008. The \$587 million accrued at March 31, 2009 consists of:

- approximately \$48 million for remediation at the Utility's natural gas compressor site located near Hinkley, California;
- approximately \$162 million for remediation at the Utility's natural gas compressor site located in Topock, Arizona, near the California border;
- approximately \$82 million related to remediation at divested generation facilities;
- approximately \$240 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
- approximately \$55 million related to remediation costs for fossil decommissioning sites.

Of the approximately \$587 million environmental remediation liability, approximately \$137 million has been included in prior rate setting proceedings. The Utility expects that an additional amount of approximately \$363 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 approximately \$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. In response to the EPA regulations, the California State Water Resources Control Board ("Water Board") issued a proposed policy to address once-through cooling. The Water Board's current proposal would require the installation of cooling towers at nuclear facilities by January 1, 2021, unless the installation of cooling towers would conflict with a nuclear safety requirement.

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. 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

In accordance with FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes," PG&E Corporation and the Utility do not expect the total amount of unrecognized tax benefits to change significantly within the next 12 months.

On January 30, 2009, PG&E Corporation reached a tentative agreement with the Internal Revenue Service ("IRS") to resolve refund claims related to the 1998 and 1999 tax years that, if approved by the U.S. Congress' Joint Committee on Taxation ("Joint Committee"), would result in a cash refund of approximately \$200 million plus interest. The refund would result in net income of approximately \$50 million. Because the agreement is subject to Joint Committee approval, PG&E Corporation has not recognized any benefit associated with the potential refund.

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

Currently, PG&E Corporation has approximately \$60 million of federal capital loss carry forwards based on tax returns as filed and after the resolution of 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 2008, PG&E Corporation began participating in the IRS's Compliance Assurance Process ("CAP"), 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.

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 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 approximately \$64 million at March 31, 2009 and approximately \$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 result of operations.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

PG&E Corporation, incorporated in California in 1995, is a holding company 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 approximately 5.1 million electricity distribution customers and approximately 4.3 million natural gas distribution customers at March 31, 2009. The Utility had approximately \$41 billion in assets at March 31, 2009 and generated revenues of approximately \$3.4 billion in the three months ended March 31, 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 Months Ended March 31, 2009

PG&E Corporation's diluted earnings per common share ("EPS") for the three months ended March 31, 2009 was \$0.65 per share, compared to \$0.62 per share for the same period in 2008. For the three months ended March 31, 2009, PG&E Corporation's income available for common shareholders increased by approximately \$17 million, or 8%, to \$241 million, compared to \$224 million for the same period in 2008.

The increase in EPS and income available for common shareholders is primarily due to the Utility's return on equity ("ROE") on higher authorized capital investments (representing a \$26 million increase in income available for common shareholders as compared to the same period in 2009). In addition, results for the three months ended March 31, 2009 reflected a benefit of approximately \$25 million because the Utility incurred lower storm- and outage-related expenses in the three months ended March 31, 2009 as compared to the same period in 2008.

This increase in diluted EPS and income available for common shareholders was partially offset by approximately \$26 million, as compared to the same period in 2008, attributable to higher uncollectible expenses due to the economic conditions in the Utility's service territory, increased employee severance costs, and an increase in the liability for non-pension employee benefits reflecting recent stock market performance and lower assumed rates of return. Additionally, during the three months ended March 31, 2009, the Utility incurred higher expenses, to perform accelerated system-wide gas integrity surveys and associated remedial work which decreased income available from common shareholders by approximately \$5 million, as compared to the same period in 2008.

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, timely recover its authorized costs, 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. 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). 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, including the CPUC's customer energy efficiency shareholder incentive mechanism. (See Note 11 of the Notes to the Condensed Consolidated Financial Statements.) 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 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 only be changed before 2011 if the annual automatic adjustment mechanism established by the CPUC is triggered. If the 12-month October-through-September average yield for the Moody's Investors Service utility bond index increases or decreases by more than 1% as compared to the applicable benchmark, the Utility can 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 net income available for 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 offset these expenses or earn an ROE until the 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, some of which include 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, PG&E Corporation will be required to contribute equity to the Utility. The timing and amount of these 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. (See "Liquidity and Financial Resources" below.)

In addition to the key factors discussed above, PG&E Corporation's and the Utility's future results of operations and financial condition are subject to the risk factors. (See "Risk Factors" in the 2008 Annual Report.)

FORWARD-LOOKING STATEMENTS

This combined quarterly report on Form 10-Q, including MD&A, 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, fires, floods, disease, other natural disasters, explosions, 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 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 new rules of 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, especially given the recent deteriorating conditions in the economy and financial markets;
- 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. 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 months ended March 31, 2009 and 2008:

(in millions)	Three Months ended March 31,	
	2009	2008
Utility		
Electric operating revenues	\$ 2,426	\$ 2,514
Natural gas operating revenues	1,005	1,219
Total operating revenues	3,431	3,733
Cost of electricity	883	1,027
Cost of natural gas	557	775
Operating and maintenance	1,059	1,036
Depreciation, amortization, and decommissioning	419	402
Total operating expenses	2,918	3,240
Operating income	513	493
Interest income	9	24
Interest expense	(173)	(180)
Other income, net	21	19
Income before income taxes	370	356
Income tax provision	131	120
Net Income	239	236
Preferred dividend requirement	3	3
Income available for common shareholders	\$ 236	\$ 233
PG&E Corporation, Eliminations, and Other ⁽¹⁾		
Operating revenues	\$ -	\$ -
Operating expenses	-	-
Operating loss	-	-
Interest income	-	2
Interest expense	(8)	(7)
Other expense, net	(3)	(14)
Loss before income taxes	(11)	(19)
Income tax benefit	(16)	(10)
Net gain (loss)	\$ 5	\$ (9)
Consolidated Total		
Operating revenues	\$ 3,431	\$ 3,733
Operating expenses	2,918	3,240
Operating income	513	493
Interest income	9	26
Interest expense	(181)	(187)
Other income, net	18	5
Income before income taxes	359	337
Income tax provision	115	110
Net Income	244	227
Preferred dividend requirement of subsidiary	3	3
Income available for common shareholders	\$ 241	\$ 224

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

Utility

The following presents the Utility's operating results for the three months ended March 31, 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 March 31,	
	2009	2008
Electric operating revenues	\$ 2,821	\$ 2,841
DWR pass-through revenues ⁽¹⁾	(395)	(327)
Utility electric operating revenues	\$ 2,426	\$ 2,514

⁽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 electric operating revenues decreased in the three months ended March 31, 2009 by approximately \$88 million, or approximately 4%, compared to the same period in 2008 mainly due to the following factors:

- Electricity procurement costs passed through to customers decreased by approximately \$147 million. (See "Cost of Electricity" below.)
- Public purpose program costs passed through to customers decreased by approximately \$29 million, as 2009 marks the beginning of a new program cycle that will run through 2011. Revenues and expenses increase as programs become more established and enrollment increases. The public purpose programs primarily consist of the electric energy efficiency programs; low-income energy efficiency programs; research, development, and demonstration programs; and renewable energy programs. (See "Operating and Maintenance" below.)

These decreases were partially offset by the following:

- Base revenues increased by approximately \$26 million as a result of attrition adjustments as authorized in the 2007 GRC.
- Revenues associated with separately funded projects placed in service, including Gateway Generating Station and the new steam generators at Diablo Canyon, increased by approximately \$46 million.
- Other miscellaneous increases in electric operating revenues of approximately \$16 million.

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. Additionally, on April 16, 2009, the CPUC approved a decision authorizing the Utility to recover approximately \$47 million, including approximately \$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. (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 impacted 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 electricity purchase costs, the cost of fuel used by 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 March 31,	
	2009	2008
Cost of purchased power	\$ 870	\$ 1,038
Proceeds from surplus sales allocated to the Utility	(31)	(46)
Fuel used in owned generation	44	35
Total cost of electricity	\$ 883	\$ 1,027
Average cost of purchased power per kWh ⁽¹⁾	\$ 0.079	\$ 0.088
Total purchased power (in millions of kWh)	10,987	11,757

⁽¹⁾ Kilowatt-hour

The Utility's total cost of electricity decreased in the three months ended March 31, 2009 by approximately \$144 million, or 14%, compared to the same period in 2008. This decrease was primarily due to a 10% decrease in the average cost of purchased power, as well as a 7% decrease in the total volume of purchased power. The decrease in the average cost of purchased power was primarily driven by lower market prices for electricity and gas. Decreases in industrial and residential demand as well as milder weather in the first quarter of 2009 contributed to decreases in the volume of purchased power.

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. Volatility in natural gas prices will also impact the Utility's cost of electricity.

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 California 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 March 31,	
	2009	2008
Bundled natural gas revenues	\$ 923	\$ 1,142
Transportation service-only revenues	82	77
Total natural gas operating revenues	\$ 1,005	\$ 1,219
Average bundled revenue per Mcf ⁽¹⁾ of natural gas sold	\$ 9.14	\$ 10.11
Total bundled natural gas sales (in millions of Mcf)	101	113

⁽¹⁾ One thousand cubic feet

The Utility's natural gas operating revenues decreased in the three months ended March 31, 2009 by approximately \$214 million, or 18%, compared to the same period in 2008. This decrease was primarily due to a decrease in bundled natural gas revenues of approximately \$219 million, or 19%, as a result of decreases in the cost of natural gas, which are passed through to customers. (See "Cost of Natural Gas" below). This decrease was partially offset by increased base revenue requirements as a result of attrition adjustments as authorized in the 2007 GRC.

Future natural gas operating revenues will be impacted 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 overall modest 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 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 March 31,	
	2009	2008
Cost of natural gas sold	\$ 515	\$ 754
Transportation cost of natural gas sold	42	21
Total cost of natural gas	\$ 557	\$ 775
Average cost per Mcf of natural gas sold	\$ 5.10	\$ 6.67
Total natural gas sold (in millions of Mcf)	101	113

The Utility's total cost of natural gas decreased in the three months ended March 31, 2009 by approximately \$218 million, or 28%, compared to the same period in 2008, primarily due to a decrease in the average market price of natural gas and a decrease in the volume of natural gas sold.

The Utility's future cost of natural gas will be impacted by the market price of natural gas, and changes in customer demand. In addition, the Utility's future cost of gas also 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 approximately \$23 million, or 2%, in the three months ended March 31, 2009 compared to the same period in 2008. Operating and maintenance expenses grew mainly due to a \$39 million increase in wage and benefit-related costs, a \$18 million increase in uncollectible customer accounts as a result of declining economic conditions and rising unemployment in the Utility's service territory, severance costs of \$8 million incurred in connection with the consolidation of some regional facilities, and increased labor and other costs of \$8 million related to accelerated natural gas leak surveys. In addition, operating and maintenance expenses for the three months ended March 31, 2008 reflected a decrease of approximately \$29 million in the Utility's accrual for employee vacation pay, contributing to the comparative increase in operating and maintenance expenses for the three months ended March 31, 2009. These increases were partially offset by decreases in public purpose program expenses of \$38 million, and decreases in labor costs of \$38 million compared to those incurred in 2008 as a result of the January 2008 winter storm. Additionally, other miscellaneous operating and maintenance expenses decreased by approximately \$3 million, as compared to the same period in 2008.

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 gas leak surveys and targets completing this work in a little more than a year. The Utility forecasts that it will spend up to \$100 million in 2009 to perform the accelerated gas leak surveys and associated remedial work. The Utility also expects that it will incur higher expenses in future periods to obtain 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

In the three months ended March 31, 2009, the Utility's depreciation, amortization, and decommissioning expenses increased by approximately \$17 million, or 4%, as compared to the same period in 2008. There was a \$26 million increase to depreciation expense primarily due to capital additions and depreciation rate changes as authorized in the 2007 GRC and the current TO rate case. This increase was partially offset by decreases of approximately \$9 million in decommissioning expense and amortization expense related to the energy recovery bonds ("ERBs").

The Utility's depreciation, amortization, and decommissioning expenses in subsequent years 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 and future TO rate cases.

Interest Income

In the three months ended March 31, 2009, the Utility's interest income decreased by approximately \$15 million, or 63%, as compared to the same period in 2008 primarily due to lower interest rates earned on restricted cash held related to Chapter 11 disputed claims. (See Note 10 of the Notes to the Condensed Consolidated Financial Statements.)

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 months ended March 31, 2009, the Utility's interest expense decreased by approximately \$7 million, or 4%, as compared to the same period in 2008. Interest expense decreased primarily due to the following factors:

- Interest expense decreased by approximately \$14 million primarily due to lower FERC interest rates accrued on the liability for disputed claims.
- Interest expense on pollution control bonds decreased by approximately \$7 million 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 approximately \$4 million primarily due to lower interest rates affecting various balancing accounts.
- Interest expense decreased by approximately \$4 million due to the reduction of the outstanding balance of ERBs.

These decreases were partially offset by additional interest expense of approximately \$22 million 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

In the three months ended March 31, 2009, the Utility's income tax expense increased by approximately \$11 million, or 9%, as compared to the same period in 2008. The effective tax rates for the three months ended March 31, 2009 and 2008 were 35.3% and 33.6%, respectively. The lower effective tax rate in 2008 was primarily the result of an Internal Revenue Service ("IRS") audit settlement included in the three months ended March 31, 2008. No similar amount was recorded in the same period in 2009.

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 months ended March 31, 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 relies on short-term debt to fund temporary financing needs.

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 access to the capital markets.

Credit Facilities and Short-Term Borrowings

At March 31, 2009, 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 approximately \$13 million, or 7%, and approximately \$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 has a \$1.75 billion commercial paper program, the borrowings from which are used primarily to cover fluctuations in cash flow requirements. Liquidity support for these borrowings is provided by available capacity under the revolving credit facility. At March 31, 2009, the Utility had \$385 million of commercial paper outstanding at an average yield of approximately 1.15%.

The following table summarizes PG&E Corporation's and the Utility's short-term borrowings and outstanding credit facilities at March 31, 2009:

(in millions)			At March 31, 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	\$ 200 ⁽¹⁾	\$ -	\$ -	\$ -	\$ 200
Utility	Revolving credit facility	February 2012	2,000 ⁽²⁾	295	-	385	1,320
Total credit facilities			<u>\$ 2,200</u>	<u>\$ 295</u>	<u>\$ -</u>	<u>\$ 385</u>	<u>\$ 1,520</u>

⁽¹⁾ Includes a \$50 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 \$950 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 March 31, 2009, PG&E Corporation and the Utility met all of these requirements.

2009 Financings

Access to the capital markets is essential to the continuation of the Utility's capital expenditure program. Notwithstanding the recent disruption in the capital markets, PG&E Corporation and the Utility were able to issue \$350 million and \$550 million, respectively, of senior unsecured notes in March 2009. Proceeds from the senior notes offerings were used to finance capital expenditures, for general working capital purposes, and to repay outstanding commercial paper, which the Utility had issued to pay off \$600 million of senior notes that matured on March 1, 2009.

In addition, PG&E Corporation issued 4,700,796 shares of common stock upon exercise of employee stock options and under its 401(k) plan and Dividend Reinvestment and Stock Purchase Plan, generating approximately \$96 million of cash through March 31, 2009. Also, in the first quarter of 2009, PG&E Corporation contributed \$528 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 three months ended March 31, 2009, the Utility paid common stock dividends totaling \$156 million to PG&E Corporation.

During the three months ended March 31, 2009, PG&E Corporation paid common stock dividends totaling \$143 million. On February 18, 2009, the Board of Directors of PG&E Corporation declared a dividend of \$0.42 per share, totaling \$154 million, which was paid on April 15, 2009 to shareholders of record on March 31, 2009.

During the three months ended March 31, 2009, the Utility paid cash dividends to holders of its outstanding series of preferred stock totaling \$3 million. On February 18, 2009, the Board of Directors of the Utility declared a cash dividend totaling \$3 million on its outstanding series of preferred stock, payable on May 15, 2009 to shareholders of record on April 30, 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 three months ended March 31, 2009 and 2008 were as follows:

(in millions)	Three Months Ended March 31,	
	2009	2008
Net income	\$ 239	\$ 236
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	456	437
Allowance for equity funds used during construction	(25)	(20)
Deferred income taxes and tax credits, net	234	160
Other changes in noncurrent assets and liabilities	(48)	106
Effect of changes in operating assets and liabilities:		
Accounts receivable	298	88
Inventories	166	107
Accounts payable	(107)	149
Income taxes receivable/payable	95	(20)
Regulatory balancing accounts, net	(180)	(356)
Other current assets	34	104
Other current liabilities	(386)	65
Other	1	(2)
Net cash provided by operating activities	\$ 777	\$ 1,054

In the three months ended March 31, 2009, net cash provided by operating activities decreased approximately \$277 million compared to the same period in 2008. This decrease was primarily due to an increase in net collateral paid of approximately \$457 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 tax refunds of approximately \$163 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.

Future operating cash flow 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 January 30, 2009, PG&E Corporation reached a tentative agreement with the IRS to resolve refund claims related to the 1998 and 1999 tax years that, if approved by the U.S. Congress's Joint Committee on Taxation ("Joint Committee"), would result in a cash refund of approximately \$200 million, plus interest. The Joint Committee's decision is currently expected in the second quarter of 2009, and if approved, PG&E Corporation expects to receive the refund by the end 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 flow 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, 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 three months ended March 31, 2009 and 2008 were as follows:

(in millions)	Three Months Ended March 31,	
	2009	2008
Capital expenditures	\$ (1,079)	\$ (853)
Proceeds from sale of assets	2	6
Decrease in restricted cash	11	2
Proceeds from nuclear decommissioning trust sales	387	164
Purchases of nuclear decommissioning trust investments	(412)	(117)
Net cash used in investing activities	\$ (1,091)	\$ (798)

Net cash used in investing activities increased by approximately \$293 million in the three months ended March 31, 2009 compared to the same period in 2008. This increase was primarily due to an increase of approximately \$226 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 three months ended March 31, 2009 and 2008 were as follows:

(in millions)	Three Months Ended March 31,	
	2009	2008
Net repayments under revolving credit facility	\$ -	\$ (250)
Net issuance (repayments) of commercial paper, net of discount of \$2 million in 2009 and \$1 million in 2008	96	(198)
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)	(300)
Energy recovery bonds matured	(89)	(83)
Preferred stock dividends paid	(3)	(3)
Common stock dividends paid	(156)	(142)
Equity contribution	528	50
Other	2	(7)
Net cash provided by (used in) financing activities	\$ 316	\$ (335)

In the three months ended March 31, 2009, net cash provided by financing activities increased by approximately \$651 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 relies on short-term debt to fund temporary financing needs.

PG&E Corporation

With the exception of dividend payments, interest, 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 three months ended March 31, 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 March 31, 2009 include \$350 million of 5.75% Senior Notes issued by PG&E Corporation due April 1, 2014, and \$550 million of 6.25% Senior Notes issued by the Utility due March 1, 2039. (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. 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 approximately \$1.99 billion, a decrease from the original forecast of \$2.3 billion, and proposed operating and maintenance expenses totaling approximately \$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 approximately \$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 March 31, 2009, the Utility has spent an aggregate of \$824 million, including capital costs of \$670 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 March 31, 2009, the Utility has incurred approximately \$661 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.

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.

Application to Recover Hydroelectric Facility Divestiture Costs

On April 16, 2009, the CPUC approved a decision to authorize the Utility to recover approximately \$47 million, including approximately \$12 million of interest, of costs 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

Due to the ongoing upheaval in the economy, there have been negative impacts on the investment returns on assets held in trust to satisfy the Utility's obligations to secure payment of employee benefits under pension and other postretirement benefit plans. The Utility's recorded liabilities and, in some cases, its funding obligations, may increase as a result of declining investment returns on trust assets and lower assumed rates of return. However, the Utility believes that it is probable that any increase in funding obligations would be recoverable through rates. On March 2, 2009, the Utility filed an application requesting that the CPUC approve a mechanism for annually adjusting gas and electric revenue requirements beginning in 2011 to cover contributions to the Utility's retirement plan outside of the GRC, which would ensure timely recovery of any additional contributions.

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

Electric Transmission Owner Rate Cases

On April 20, 2009, the Utility requested that the FERC approve an uncontested settlement in the Utility's TO rate case that was filed on July 30, 2008. The settlement proposes to set an annual retail base revenue requirement of \$776 million effective March 1, 2009. The Utility has been reserving the difference between expected revenues based on rates requested by the Utility in its TO rate application and expected revenues based on rates proposed in the settlement. As a result, the settlement, if approved, will not impact the Utility's results of operations or financial condition. If the settlement is approved by the FERC, the Utility will refund any over-collected amounts to customers, with interest, through an adjustment to rates in 2011.

RISK MANAGEMENT ACTIVITIES

The Utility and PG&E Corporation, mainly through its ownership of the Utility, are exposed to market risk, which is the risk that changes in market conditions will adversely affect net income or cash flows. PG&E Corporation and the Utility face market risk associated with their operations, financing arrangements, the marketplace for electricity, natural gas, electricity transmission, natural gas transportation and

storage, other goods and services, and other aspects of their businesses. PG&E Corporation and the Utility categorize market risks as price risk and interest rate risk. The Utility is also exposed to credit risk: the risk that counterparties fail to perform their contractual obligations. 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. Therefore, 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 reduced. The CAISO must implement several FERC-ordered changes to MRTU, some of which must be implemented by March 31, 2010. Market risks, if any, associated with these changes will be assessed as the design and timelines are finalized during 2009.

Electric Transmission Congestion Revenue Rights

In the CAISO's new day-ahead market, the CAISO imposes electric transmission congestion costs and credits that are determined by reference points along transmissions paths at which power is delivered or withdrawn. The CAISO allows market participants, including load serving entities such as the Utility, to acquire congestion revenue rights ("CRRs") to hedge the financial risk of CAISO-imposed congestion charges. The CAISO releases CRRs through an annual and monthly process, each of which includes both an allocation phase (in which load serving entities receive CRRs at no cost based on the customer demand or "load" they serve) and an auction phase (priced at market and available to all market participants). The Utility acquired CRRs in 2008 (via allocation and auction) in anticipation of the effectiveness of the MRTU. In the first quarter of 2009 the Utility acquired additional CRRs. CRRs are considered derivative instruments and are recorded at fair value within the Condensed Consolidated Balance Sheets.

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

The Utility's value-at-risk calculated under the methodology described above was approximately \$10 million at March 31, 2009. The Utility's high, low, and average values-at-risk during the three months ended March 31, 2009 were approximately \$34 million, \$9 million, and \$22 million, respectively.

Convertible Subordinated Notes

At March 31, 2009, PG&E Corporation had outstanding approximately \$252 million of 9.50% Convertible Subordinated Notes that are scheduled to mature on June 30, 2010. These Convertible Subordinated Notes may be converted (at the option of the holder) at any time prior to maturity into 16,702,194 shares of PG&E Corporation common stock, at a conversion price of \$15.09 per share. In addition, 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 price. Since January 1, 2009, PG&E Corporation has paid pass-through dividends totaling approximately \$14 million, including \$7 million paid on April 15, 2009.

In accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS No. 133"), the dividend participation rights of 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. (See Notes 7 and 8 of the Notes to the Condensed Consolidated Financial Statements.)

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 March 31, 2009, if interest rates changed by 1% for all current variable rate debt issued by PG&E Corporation and the Utility, the change would affect net income for the three months ended March 31, 2009 by approximately \$0.9 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 ties many energy contracts to master agreements 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 March 31, 2009 and December 31, 2008:

(in millions)	Gross Credit Exposure Before Credit Collateral ⁽¹⁾	Credit Collateral	Net Credit Exposure ⁽²⁾	Number of Wholesale Customers or Counterparties >10%	Net Exposure to Wholesale Customers or Counterparties >10%
March 31, 2009	\$ 315	\$ 63	\$ 252	3	\$ 192
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 March 31, 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

In March 2008, the Financial Accounting Standards Board (“FASB”) issued 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. 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. SFAS No. 161 is effective prospectively for fiscal years beginning after November 15, 2008. (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.

As of March 31, 2009 and December 31, 2008, PG&E Corporation’s \$252 million preferred stock of subsidiary represents a noncontrolling interest in the Utility. PG&E Corporation has reclassified the noncontrolling interest 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 March 31, 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, the adoption of SFAS No. 160 had no material impact on PG&E Corporation’s and the Utility’s Condensed Consolidated Financial Statements.

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

In September 2008, the FASB issued 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. EITF 08-5 is effective prospectively for fiscal years beginning on or after December 15, 2008 and interim periods within those fiscal years. EITF 08-5 did not have a material impact on PG&E Corporation’s and the Utility’s Condensed Consolidated Financial Statements.

Equity Method Investment Accounting Consideration — an amendment to Accounting Principles Board No. 18

In November 2008, the FASB issued 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(R), “Business Combinations.” However, the investor of 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. EITF 08-6 is effective prospectively for fiscal years beginning on or after December 15, 2008 and interim periods within those fiscal years. Adoption of EITF 08-6 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

Disclosures about Employers' Postretirement Benefit Plan Assets — an amendment to FASB Statement No. 132(R)

In December 2008, the FASB issued FASB Staff Position ("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, "Employers' Disclosures about Pensions and Other Postretirement Benefits." 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 fiscal years ending after December 15, 2009. PG&E Corporation and the Utility are currently evaluating the impact of FSP SFAS 132(R)-1.

Interim Disclosures about Fair Value of Financial Instruments

In April 2009, the FASB issued FSP SFAS 107-1 and APB No. 28-1, "Interim Disclosures about Fair Value of Financial Instruments" ("FSP SFAS 107-1 and APB No. 28-1"). This FSP amends SFAS No. 107 and APB 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. FSP SFAS 107-1 and APB No. 28-1 is effective prospectively for interim reporting periods after June 15, 2009. PG&E Corporation and the Utility are currently evaluating the impact of FSP SFAS 107-1 and APB No. 28-1.

Recognition and Presentation of Other-Than-Temporary Impairments

In April 2009, the FASB issued FSP SFAS 115-2 and SFAS 124-2, "Recognition and Presentation of Other-Than-Temporary Impairments" ("FSP SFAS 115-2 and SFAS 124-2"). This FSP amends existing guidance related to other-than-temporary impairments to improve disclosure of other-than-temporary impairments on debt and equity securities in the financial statements. Recognition and measurement guidance is not amended by this FSP. FSP SFAS 115-2 and SFAS 124-2 is effective prospectively for interim reporting periods after June 15, 2009. PG&E Corporation and the Utility are currently evaluating the impact of FSP SFAS 115-2 and SFAS 124-2.

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

In April 2009, the FASB issued 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," to provide guidance on estimating fair value when the volume or level of activity for an asset or liability has significantly decreased when compared with normal market conditions. Guidance to identify circumstances when a transaction is not orderly, or is distressed or forced, is also provided. FSP SFAS 157-4 is effective prospectively for interim reporting periods after June 15, 2009. PG&E Corporation and the Utility are currently evaluating the impact of FSP SFAS 157-4.

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 March 31, 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 March 31, 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

On March 10, 2009, the San Francisco Superior Court dismissed the California Attorney General's lawsuit filed in 2002 against PG&E Corporation and several of its present and former directors. The Attorney General alleged that the defendants had engaged in unfair or fraudulent business acts or practices in violation of Section 17200 of the California Business and Professions Code. Among other allegations, the Attorney General alleged that past transfers of funds from the Utility to PG&E Corporation during the period from 1997 through 2000 (primarily in the form of dividends and stock repurchases), and allegedly from PG&E Corporation to other affiliates of PG&E Corporation, violated various conditions established by the CPUC. Following a neutral evaluation of the Attorney General's claims by a former California Supreme Court justice, the Attorney General and the defendants jointly requested that the complaint be dismissed. The dismissal is with prejudice, meaning that the Attorney General cannot re-file the complaint. On April 23, 2009, the City and County of San Francisco dismissed its similar lawsuit against PG&E Corporation. For more information about these matters, see PG&E Corporation's and Pacific Gas and Electric Company's joint Annual Report on Form 10-K for the year ended December 31, 2008.

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. There have been no material changes in the risks related to an investment in PG&E Corporation's or the Utility's securities that have been disclosed in the 2008 Annual Report. In addition, the section of this report entitled "Forward-Looking Statements" appearing in Part I, Item 2: Management's Discussion and Analysis of Financial Condition and Results of Operations, lists some of the factors that could affect PG&E Corporation's and the Utility's future results of operations and financial condition. Although PG&E Corporation and the Utility are not able to predict all the factors that may affect future results, the listed factors and the risks discussed in the 2008 Annual Report could cause actual results to differ materially from the results expected or anticipated by management as expressed or implied by the forward-looking statements made in the 2008 Annual Report and in this report.

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

During the quarter ended March 31, 2009, PG&E Corporation made equity contributions totaling \$528 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 March 31, 2009, PG&E Corporation issued 1,855,865 shares of common stock at a conversion price of \$15.09 per share in an unregistered offering upon conversion of \$28 million principal amount of PG&E Corporation 9.50% Convertible Subordinated Notes originally issued in an unregistered offering in 2002.

Issuer Purchases of Equity Securities

PG&E Corporation common stock:

Period	Total Number of Shares Purchased	Average Price Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs
January 1 through January 31, 2009	36,672 ⁽¹⁾	\$ 38.81	-	\$ -
February 1 through February 28, 2009	-	-	-	-
March 1 through March 31, 2009	-	-	-	-
Total	36,672	\$ 38.81	-	\$ -

⁽¹⁾ Shares tendered to satisfy tax withholding obligations arising upon the vesting of PG&E Corporation restricted stock.

During the first quarter of 2009, the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.

ITEM 5. OTHER INFORMATION

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

The Utility's earnings to fixed charges ratio for the three months ended March 31, 2009 was 2.71. The Utility's earnings to combined fixed charges and preferred stock dividends ratio for the three months ended March 31, 2009 was 2.66. 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 three months ended March 31, 2009 was 2.60 . 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

- 3.1 Bylaws of PG&E Corporation amended as of January 1, 2009 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 3.3)
- 3.2 Bylaws of Pacific Gas and Electric Company amended as of January 1, 2009 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 3.5)
- 4.1 Sixth Supplemental Indenture, dated as of March 6, 2009 relating to the issuance of \$550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 6.25% Senior Notes due March 1, 2039 (incorporated by reference to Pacific Gas and Electric Company's Current Report on Form 8-K dated March 6, 2009 (File No. 1-2348), Exhibit 4.1)
- 4.2 First Supplemental Indenture, dated as of March 12, 2009 relating to the issuance of \$350,000,000 aggregate principal amount of PG&E Corporation's 5.75% Senior Notes due April 1, 2014 (incorporated by reference to PG&E Corporation's Current Report on Form 8-K dated March 10, 2009 (File No. 1-12609), Exhibit 4.1)
- 10.1* Restricted Stock Unit Agreement between Peter A. Darbee and PG&E Corporation dated January 2, 2009 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.12)
- 10.2* Form of Restricted Stock Unit Agreement for 2009 grants under the PG&E Corporation 2006 Long-Term Incentive Plan
- 10.3* Form of Performance Share Agreement for 2009 grants under the PG&E Corporation 2006 Long-Term Incentive Plan
- 11 Computation of Earnings Per Common 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

* Management contract or compensatory agreement

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

SIGNATURES

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

PG&E CORPORATION

CHRISTOPHER P. JOHNS

Christopher P. Johns
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: May 6, 2009

EXHIBIT INDEX

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* Management contract or compensatory agreement

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

**PG&E CORPORATION
2006 LONG-TERM INCENTIVE PLAN
RESTRICTED STOCK UNIT GRANT**

PG&E CORPORATION, a California corporation, hereby grants Restricted Stock Units to the Recipient named below. The Restricted Stock Units have been granted under the PG&E Corporation 2006 Long-Term Incentive Plan, as amended (the "LTIP"). The terms and conditions of the Restricted Stock Units are set forth in this cover sheet and in the attached Restricted Stock Unit Agreement (the "Agreement").

Date of Grant: March 9, 2009

Name of Recipient: _____.

Last Four Digits of Recipient's Social Security Number: _____

Number of Restricted Stock Units: _____.

By signing this cover sheet, you agree to all of the terms and conditions described in the attached Agreement. You and PG&E Corporation agree to execute such further instruments and to take such further action as may reasonably be necessary to carry out the intent of the attached Agreement. You are also acknowledging receipt of this Grant, the attached Agreement, and a copy of the prospectus describing the LTIP and the Restricted Stock Units dated March 1, 2009.

Recipient: _____
(Signature)

Attachment

Please sign and return to PG&E Corporation, Human Resources,
One Market, Spear Tower, Suite 400, San Francisco, California 94105.

PG&E CORPORATION

2006 LONG-TERM INCENTIVE PLAN

RESTRICTED STOCK UNIT AGREEMENT

The LTIP and Other Agreements

This Agreement constitutes the entire understanding between you and PG&E Corporation regarding the Restricted Stock Units, subject to the terms of the LTIP. Any prior agreements, commitments, or negotiations are superseded. In the event of any conflict or inconsistency between the provisions of this Agreement and the LTIP, the LTIP shall govern. Capitalized terms that are not defined in this Agreement are defined in the LTIP. In the event of any conflict between the provisions of this Agreement and the PG&E Corporation Officer Severance Policy, this Agreement shall govern. For purposes of this Agreement, employment with PG&E Corporation shall mean employment with any member of the Participating Company Group.

Grant of Restricted Stock Units

PG&E Corporation grants you the number of Restricted Stock Units shown on the cover sheet of this Agreement. The Restricted Stock Units are subject to the terms and conditions of this Agreement and the LTIP.

Vesting of Restricted Stock Units

As long as you remain employed with PG&E Corporation, 20 percent of the total number of Restricted Stock Units originally subject to this Agreement, as shown above on the cover sheet, will vest on the first business day of March of each of the first, second and third years following the Date of Grant, and the additional 40 percent of the total number of shares of Restricted Stock Units will vest on the on the first business day of March of the fourth year following the Date of Grant (collectively, the "Normal Vesting Schedule"). The amounts payable upon each vesting date are hereby designated separate payments for purposes of Code Section 409A. Except as described below, all Restricted Stock Units subject to this Agreement which have not vested upon termination of your employment shall then be automatically cancelled. As set forth below, the Restricted Stock Units may vest earlier upon the occurrence of certain events.

Dividends

Restricted Stock Units will accrue Dividend Equivalents in the event cash dividends are paid with respect to PG&E Corporation common stock having a record date prior to the date on which the Restricted Stock Units are settled. Such Dividend Equivalents will be converted into cash and paid, if at all, upon settlement of the underlying Restricted Stock Units.

Settlement

Vested Restricted Stock Units will be settled in an equal number of shares of PG&E Corporation common stock. PG&E Corporation shall issue such shares as soon as practicable after the Restricted Stock Units vest in accordance with the Normal Vesting Schedule (but not later than sixty (60) days after the applicable vesting date); provided, however, that such issuance shall, if earlier, be made with respect to all of your outstanding vested Restricted Stock Units (after giving effect to the vesting provisions described below) as soon as practicable after (but not later than sixty (60) days after) the earliest to occur of your (1) Disability (as defined under Code Section 409A), (2) death or (3) "separation from service," within the meaning of Code Section 409A within 2 years following a Change in Control.

Voluntary Termination

In the event of your voluntary termination (other than Retirement), all unvested Restricted Stock Units will be cancelled on the date of termination and any associated Dividend Equivalents that have not yet been converted shall be forfeited on the date of termination.

Retirement

In the event of your Retirement, unvested Restricted Stock Units will continue to vest and be settled pursuant to the Normal Vesting Schedule (without regard to the requirement that you be employed), subject to the earlier settlement provisions of this Agreement; provided, however that in the event of your Retirement within 2 years following a Change in Control, all of your Restricted Stock Units shall vest and be settled as soon as practicable after (but not later than sixty (60) days after) the date of such event. Your voluntary termination of employment will be considered to be a Retirement if you are both age 55 or older on the date of termination and if you were employed by PG&E Corporation for at least five consecutive years ending on the date of termination of your employment.

Termination for Cause	If your employment with PG&E Corporation is terminated at any time by PG&E Corporation for cause, all unvested Restricted Stock Units will be cancelled on the date of termination. In general, termination for “cause” means termination of employment because of dishonesty, a criminal offense or violation of a work rule, and will be determined by and in the sole discretion of PG&E Corporation.
Termination other than for Cause	If your employment with PG&E Corporation is terminated by PG&E Corporation other than for cause and you are an officer in Bands 1-5, any unvested Restricted Stock Units that would have vested during the period of the “Severance Multiple” under the Officer Severance Policy will continue to vest and be settled pursuant to the Normal Vesting Schedule (without regard to the requirement that you be employed), subject to the earlier settlement provisions of this Agreement. In the event of your involuntary termination other than for cause, if you are not an officer in Bands 1-5, any unvested Restricted Stock Units that would have vested within the 12 months following such termination had your employment continued will continue to vest and be settled pursuant to the Normal Vesting Schedule (without regard to the requirement that you be employed), subject to the earlier settlement provisions of this Agreement. All other unvested Restricted Stock Units will be cancelled on the date of termination.
Death/Disability	In the event of your death or Disability while you are employed, all of your Restricted Stock Units shall vest and be settled as soon as practicable after (but not later than sixty (60) days after) the date of such event. If your death or Disability occurs following the termination of your employment and your Restricted Stock Units are then outstanding under the terms hereof, then all of your vested Restricted Stock Units plus any Restricted Stock Units that would have otherwise vested during any continued vesting period hereunder shall be settled as soon as practicable after (but not later than sixty (60) days after) the date of your death or Disability.
Termination Due to Disposition of Subsidiary	(1) If your employment is terminated (other than termination for cause, your voluntary termination, or your Retirement) by reason of a divestiture or change in control of a subsidiary of PG&E Corporation, which divestiture or change in control results in such subsidiary no longer qualifying as a subsidiary corporation under Section 424(f) of the Internal Revenue Code of 1986, as amended (the “Code”), or (2) if your employment is terminated (other than termination for cause, your voluntary termination, or your Retirement) coincident with the sale of all or substantially all of the assets of a subsidiary of PG&E Corporation, the Restricted Stock Units shall vest and be settled in the same manner as for a “Termination other than for Cause” described above.
Change in Control	In the event of a Change in Control, the surviving, continuing, successor, or purchasing corporation or other business entity or parent thereof, as the case may be (the “Acquiror ”), may, without your consent, either assume or continue PG&E Corporation’s rights and obligations under this Agreement or provide a substantially equivalent award in substitution for the Restricted Stock Units subject to this Agreement. If the Restricted Stock Units are neither assumed nor continued by the Acquiror or if the Acquiror does not provide a substantially equivalent award in substitution for the Restricted Stock Units, all of your unvested Restricted Stock Units shall automatically vest immediately preceding and contingent on, the Change in Control and be settled in accordance with the Normal Vesting Schedule, subject to the earlier settlement provisions of this Agreement.
Termination In Connection with a Change in Control	If you separate from service (other than termination for cause, your voluntary termination, or your Retirement) in connection with a Change in Control within three months before the Change in Control occurs or within two years following the Change in Control, all of your outstanding Restricted Stock Units (to the extent they did not previously vest upon, for example, failure of the Acquiror to assume or continue this Award) shall automatically vest on the date of the Change in Control or the date of such separation, whichever is later. In the event of such a separation in connection with a Change in Control within two years following the Change in Control, your Restricted Stock Units will be settled as soon as practicable after (but not later than sixty (60) days after) the date of such separation. In the event of such a separation in connection with a Change in Control within three months before the Change in Control occurs, your Restricted Stock Units will be settled in accordance with the Normal Vesting Schedule (without regard to the requirement that you be employed) subject to the earlier settlement provisions of this Agreement. PG&E Corporation shall have the sole discretion to determine whether termination of your employment was made in connection with a Change in Control.

Delay

PG&E Corporation shall delay the issuance of any shares of common stock to the extent it is necessary to comply with Section 409A(a)(2)(B)(i) of the Code (relating to payments made to certain “key employees” of certain publicly-traded companies); in such event, any shares of common stock to which you would otherwise be entitled during the six (6) month period following the date of your “separation from service” under Section 409A (or shorter period ending on the date of your death following such separation) will instead be issued on the first business day following the expiration of the applicable delay period.

Withholding Taxes

Prior to any event in connection with the Restricted Stock Units (e.g., vesting) that PG&E Corporation determines may result in any tax withholding obligation, whether United States federal, state, local, or non-U.S., including any social insurance, employment tax, payment on account, or other tax-related obligation (the “Tax Withholding Obligation”), you must arrange for the satisfaction of the amount of such Tax Withholding Obligation in a manner acceptable to PG&E Corporation.

PG&E Corporation may, at its discretion, provide you with one or more of the following methods to satisfy your Tax Withholding Obligation:

- Sell shares of PG&E Corporation common stock issuable to you and use the sales proceeds to pay the amount due. (PG&E Corporation may be able to assist you in selling your shares through a broker so that you can use the sales proceeds to satisfy applicable taxes.)
- Pay the amount due by cash or check.
- Instruct PG&E Corporation to withhold from the shares of PG&E Corporation common stock issuable to you a number of whole shares of Stock having a Fair Market Value, as determined by PG&E Corporation, equal to all or any part of the amount due, up to the amount of your Tax Withholding Obligation calculated using the applicable minimum statutory withholding rates. If the withheld shares were not sufficient to satisfy your minimum Tax Withholding Obligation, you would be required to pay, as soon as practicable, including through additional payroll withholding, any amount of the Tax Withholding Obligation that is not satisfied by the withholding of shares described above.

Leaves of Absence

For purposes of this Agreement, if you are on an approved leave of absence from PG&E Corporation, or a recipient of PG&E Corporation sponsored disability benefits, you will continue to be considered as employed. If you do not return to active employment upon the expiration of your leave of absence or the expiration of your PG&E Corporation sponsored disability benefits, you will be considered to have voluntarily terminated your employment. See above under “Voluntary Termination.”

Notwithstanding the foregoing, if the leave of absence exceeds six (6) months, and a return to service upon expiration of such leave is not guaranteed by statute or contract, then you shall be deemed to have had a “separation from service” for purposes of any Restricted Stock Units that are settled hereunder upon such separation. To the extent an authorized leave of absence is due to a medically determinable physical or mental impairment that can be expected to result in death or to last for a continuous period of at least six (6) months and such impairment causes you to be unable to perform the duties of your position of employment or any substantially similar position of employment, the six (6) month period in the prior sentence shall be twenty-nine (29) months.

PG&E Corporation reserves the right to determine which leaves of absence will be considered as continuing employment and when your employment terminates for all purposes under this Agreement.

Voting and Other Rights

You shall not have voting rights with respect to the Restricted Stock Units until the date the underlying shares are issued (as evidenced by appropriate entry on the books of PG&E Corporation or its duly authorized transfer agent).

No Retention Rights

This Agreement is not an employment agreement and does not give you the right to be retained by PG&E Corporation. Except as otherwise provided in an applicable employment agreement, PG&E Corporation reserves the right to terminate your employment at any time and for any reason.

Applicable Law

This Agreement will be interpreted and enforced under the laws of the State of California.

PG&E CORPORATION
2006 LONG-TERM INCENTIVE PLAN

PERFORMANCE SHARE GRANT

PG&E CORPORATION, a California corporation, hereby grants Performance Shares to the Recipient named below. The Performance Shares have been granted under the PG&E Corporation 2006 Long-Term Incentive Plan, as amended (the "LTIP"). The terms and conditions of the Performance Shares are set forth in this cover sheet and the attached Performance Share Agreement (the "Agreement").

Date of Grant: March 9, 2009

Name of Recipient: _____

Last Four Digits of Recipient's Social Security Number: _____

Number of Performance Shares: _____

By signing this cover sheet, you agree to all of the terms and conditions described in the attached Agreement. You and PG&E Corporation agree to execute such further instruments and to take such further action as may reasonably be necessary to carry out the intent of the attached Agreement. You are also acknowledging receipt of this Grant, the attached Agreement, and a copy of the prospectus describing the LTIP and the Performance Shares dated March 1, 2009.

Recipient: _____
(Signature)

Attachment

*Please sign and return to PG&E Corporation, Human Resources,
One Market, Spear Tower, Suite 400, San Francisco, California 94105*

PG&E CORPORATION 2006 LONG-TERM INCENTIVE PLAN

PERFORMANCE SHARE AGREEMENT

The LTIP and Other Agreements

This Agreement constitutes the entire understanding between you and PG&E Corporation regarding the Performance Shares, subject to the terms of the LTIP. Any prior agreements, commitments or negotiations are superseded. In the event of any conflict or inconsistency between the provisions of this Agreement and the LTIP, the LTIP shall govern. Capitalized terms that are not defined in this Agreement are defined in the LTIP. In the event of any conflict between the provisions of this Agreement and the PG&E Corporation Officer Severance Policy, this Agreement shall govern.

For purposes of this Agreement, employment with PG&E Corporation shall mean employment with any member of the Participating Company Group.

Grant of Performance Shares

PG&E Corporation grants you the number of Performance Shares shown on the cover sheet of this Agreement. The Performance Shares are subject to the terms and conditions of this Agreement and the LTIP.

Vesting of Performance Shares

As long as you remain employed with PG&E Corporation, the Performance Shares will vest on the first business day of March (the “Vesting Date”) of the third year following the date of grant specified in the cover sheet. Except as described below, all Performance Shares subject to this Agreement that have not vested shall be forfeited upon termination of your employment.

Payment of Performance Shares

Upon the Vesting Date, PG&E Corporation’s total shareholder return (TSR) will be compared to the TSR of the twelve other companies in PG&E Corporation’s comparator group ¹ for the prior three calendar years (the “Performance Period”). Subject to rounding considerations, there will be no payout for TSR below the 25th percentile of the comparator group; TSR at the 25th percentile will result in a 25% payout of Performance Shares; TSR at the 75th percentile will result in a 100% payout of Performance Shares; and TSR in the top rank will result in a 200% payout of Performance Shares. The following table sets forth the payout percentages for the various TSR rankings that could be achieved:

**Number of Companies in
Total (Including PG&E Corporation) - 13**

Rank	Performance Percentile	Rounded Payout
1	100%	200%
2	92%	170%
3	83%	130%
4	75%	100%
5	67%	90%
6	58%	75%
7	50%	65%
8	42%	50%
9	33%	35%
10	25%	25%
11	17%	0%
12	8%	0%
13	0%	0%

The payment will equal the product of the number of vested Performance Shares, the applicable payout percentage, and the average closing price of a share of PG&E Corporation common stock for the last 30 calendar days of the year preceding the Vesting Date as reported on the New York Stock Exchange. Payments, if any, will be made as soon as practicable following the date that the Compensation Committee of the PG&E Corporation Board of Directors certifies the TSR percentile rank over the Performance Period pursuant to Section 10.5(a) of the LTIP, but in any event within sixty (60) days of the Vesting Date.

¹ The identities of the companies currently comprising the comparator group are included in the prospectus. PG&E Corporation reserves the

right to change the companies comprising the comparator group at any time.

Dividends

Each time that PG&E Corporation declares a dividend on its shares of common stock, an amount equal to the dividend multiplied by the number of Performance Shares granted to you by this Agreement shall be accrued on your behalf. If you receive a Performance Share payout in accordance with the preceding paragraph, at that same time you also shall receive a cash payment equal to the amount of any dividends accrued with respect to your Performance Shares over the Performance Period multiplied by the same payout percentage used to determine the amount of the Performance Share payout.

Voluntary Termination

If you terminate your employment with PG&E Corporation voluntarily before the Vesting Date (other than for Retirement), all of the Performance Shares shall be cancelled as of the date of such termination and any dividends accrued with respect to your Performance Shares shall be forfeited.

Termination for Cause

If your employment with PG&E Corporation is terminated at any time by PG&E Corporation for cause before the Vesting Date, all of the Performance Shares shall be cancelled as of the date of such termination and any dividends accrued with respect to your Performance Shares shall be forfeited. In general, termination for “cause” means termination of employment because of dishonesty, a criminal offense or violation of a work rule, and will be determined by and in the sole discretion of PG&E Corporation.

Termination other than for Cause

If your employment with PG&E Corporation is terminated by PG&E Corporation other than for cause before the Vesting Date, your unvested Performance Shares will vest proportionally based on the number of months during the Performance Period that you were employed (rounded down) divided by the number of months in the Performance Period (36 months). All other outstanding Performance Shares (and any associated accrued dividends) shall automatically be cancelled upon such termination. Your vested Performance Shares will be payable, if at all, as soon as practicable after the Vesting Date based on the same formula applied to active employees and in any event within sixty (60) days of the Vesting Date. At that time you also shall receive a cash payment, if any, equal to the amount of dividends accrued over the Performance Period with respect to your vested Performance Shares multiplied by the same payout percentage used to determine the amount, if any, of the Performance Share payout.

Retirement

If you retire before the Vesting Date, your outstanding Performance Shares will continue to vest as though your employment had continued and will be payable, if at all, as soon as practicable following the Vesting Date and in any event within sixty (60) days of the Vesting Date. At the same time you also shall also receive a cash payment, if any, equal to the amount of dividends accrued over the Performance Period with respect to your Performance Shares multiplied by the same payout percentage used to determine the amount, if any, of the Performance Share payout. You will be considered to have retired if you are age 55 or older on the date of termination and if you were employed by PG&E Corporation for at least five consecutive years ending on the date of termination of your employment.

Death/Disability

If your employment terminates due to your death or disability before the Vesting Date, all of your Performance Shares shall immediately vest and will be payable, if at all, as soon as practicable after the Vesting Date and in any event within sixty (60) days of the Vesting Date based on the same formula applied to active employees. At that same time you also shall receive a cash payment, if any, equal to the amount of dividends accrued over the Performance Period with respect to your Performance Shares multiplied by the same payout percentage used to determine the amount, if any, of the Performance Share payout.

Termination Due to Disposition of Subsidiary

(1) If your employment is terminated (other than for cause or your voluntary termination) by reason of a divestiture or change in control of a subsidiary of PG&E Corporation, which divestiture or change in control results in such subsidiary no longer qualifying as a subsidiary corporation under Section 424(f) of the Internal Revenue Code of 1986, as amended, or (2) if your employment is terminated (other than for cause or your voluntary termination) coincident with the sale of all or substantially all of the assets of a subsidiary of PG&E Corporation, all Performance Shares shall vest proportionally based on the number of months during the Performance Period that you were employed (rounded down) divided by the number of months in the Performance Period (36 months). All other outstanding Performance Shares (and any associated accrued dividends) shall automatically be cancelled upon such termination. Your vested Performance Shares will be payable, if at all, as soon as practicable after the Vesting Date and in any event within sixty (60) days of the

Vesting Date, based on the same formula applied to active employees. At that same time you also shall receive a cash payment, if any, equal to the amount of dividends accrued over the Performance Period with respect to your vested Performance Shares multiplied by the same payout percentage used to determine the amount, if any, of the Performance Share payout.

Change in Control

In the event of a Change in Control, the surviving, continuing, successor, or purchasing corporation or other business entity or parent thereof, as the case may be (the “Acquiror ”), may, without your consent, either assume or continue PG&E Corporation’s rights and obligations under this Agreement or provide a substantially equivalent award in substitution for the Performance Shares subject to this Agreement. If the Acquiror assumes or continues PG&E Corporation’s rights and obligations under this Agreement or substitutes a substantially equivalent award, TSR shall be calculated by aggregating (a) the TSR of PG&E Corporation for the period from January 1 of the year of grant to the date of the Change in Control, and (b) the TSR of the Acquiror from the date of the Change in Control to the last calendar day of the year preceding the Vesting Date. The payout percentage reflected in the table set forth above for the highest percentile TSR performance met or exceeded when calculated on that basis, and considering any adjustments to the comparator group, will be used to determine the amount of the payout, if any, upon settlement of the assumed, continued or substituted award, which settlement shall occur as soon as practicable after the Vesting Date and in any event within sixty (60) days of the Vesting Date. At that time you also shall receive a cash payment, if any, equal to the amount of dividends accrued with respect to your Performance Shares over the Performance Period multiplied by the same payout percentage used to determine the amount, if any, of the Performance Share payout.

If the Change in Control of PG&E Corporation occurs before the original Vesting Date, and if this Award is neither assumed nor continued by the Acquiror or if the Acquiror does not provide a substantially equivalent award in substitution for the Performance Shares subject to this Agreement, all of your outstanding Performance Shares shall automatically vest and become nonforfeitable on the date of the Change in Control. Such vested Performance Shares will become payable, if at all, as soon as practicable following the original Vesting Date and in any event within sixty (60) days of the original Vesting Date. The payment, if any, will be based on PG&E Corporation’s TSR for the period from January 1 of the year of grant to the date of the Change in Control compared to the TSR of the other companies in PG&E Corporation’s comparator group ² for the same period. The payment will be calculated by multiplying the number of vested Performance Shares by the payout percentage. The resulting number of Performance Shares will be multiplied by the average closing price of a share of PG&E

Corporation common stock for the last 30 calendar days preceding the Change in Control as reported on the New York Stock Exchange. At the same time you also shall receive a cash payment, if any, equal to the amount of dividends accrued with respect to your Performance Shares to the date of the Change in Control multiplied by the same payout percentage used to determine the amount, if any, of the Performance Share payout.

² The identities of the companies currently comprising the comparator group are included in the prospectus. PG&E Corporation reserves the right to change the companies comprising the comparator group at any time.

Termination In Connection with a Change in Control

If your employment is terminated in connection with a Change in Control within three months before the Change in Control occurs or within two years following the Change in Control, all of your outstanding Performance Shares (to the extent they did not previously vest upon failure of the Acquiror to assume or continue this Award) shall automatically vest and become nonforfeitable on the date of termination of your employment. Your vested Performance Shares will be payable, if at all, as soon as practicable following the original Vesting Date and in any event within sixty (60) days of the Vesting Date and will be based on the same formula applied to active employees. You shall also at that time receive a cash payment, if any, equal to the amount of dividends accrued over the Performance Period with respect to your vested Performance Shares multiplied by the same payout percentage used to determine the amount, if any, of the Performance Share payout.

PG&E Corporation shall have the sole discretion to determine whether termination of your employment was made in connection with a Change in Control.

Withholding Taxes

PG&E Corporation will withhold amounts necessary to satisfy applicable taxes from the payment to be made with respect to your Performance Shares. You will receive the remaining proceeds in cash.

Leaves of Absence

For purposes of this Agreement, if you are on an approved leave of absence from PG&E Corporation, or a recipient of PG&E Corporation sponsored disability benefits, you will continue to be considered as employed. If you do not return to active employment upon the expiration of your leave of absence or the expiration of your PG&E Corporation sponsored disability benefits, you will be considered to have voluntarily terminated your employment. See above under "Voluntary Termination."

PG&E Corporation reserves the right to determine which leaves of absence will be considered as continuing employment and when your employment terminates for all purposes under this Agreement.

No Retention Rights

This Agreement is not an employment agreement and does not give you the right to be retained by PG&E Corporation. Except as otherwise provided in an applicable employment agreement, PG&E Corporation reserves the right to terminate your employment at any time and for any reason.

Applicable Law

This Agreement will be interpreted and enforced under the laws of the State of California.

By signing the cover sheet of this Agreement, you agree to all of the terms and conditions described above and in the LTIP.

EXHIBIT 11
PG&E CORPORATION
COMPUTATION OF EARNINGS PER COMMON SHARE

(in millions, except per share amounts)	Three Months Ended March 31,	
	2009	2008
Income Available for Common Shareholders	\$ 241	\$ 224
Less: distributed earnings to common shareholders	154	139
Undistributed earnings	<u>\$ 87</u>	<u>\$ 85</u>
Common shareholders earnings		
Basic		
Distributed earnings to common shareholders	\$ 154	\$ 139
Undistributed earnings allocated to common shareholders	<u>83</u>	<u>81</u>
Total common shareholders earnings, basic	<u>\$ 237</u>	<u>\$ 220</u>
Diluted		
Distributed earnings to common shareholders	\$ 154	\$ 139
Undistributed earnings allocated to common shareholders	<u>83</u>	<u>81</u>
Total common shareholders earnings, diluted	<u>\$ 237</u>	<u>\$ 220</u>
Weighted average common shares outstanding, basic	364	355
9.50% Convertible Subordinated Notes	<u>17</u>	<u>19</u>
Weighted average common shares outstanding and participating securities, basic	<u>381</u>	<u>374</u>
Weighted average common shares outstanding, basic	364	355
Employee share-based compensation	<u>2</u>	<u>1</u>
Weighted average common shares outstanding, diluted	366	356
9.50% Convertible Subordinated Notes	<u>17</u>	<u>19</u>
Weighted average common shares outstanding and participating securities, diluted	<u>383</u>	<u>375</u>
Net earnings per common share, basic		
Distributed earnings, basic ⁽¹⁾	\$ 0.42	\$ 0.39
Undistributed earnings, basic	<u>0.23</u>	<u>0.23</u>
Total	<u>\$ 0.65</u>	<u>\$ 0.62</u>
Net earnings per common share, diluted		
Distributed earnings, diluted	\$ 0.42	\$ 0.39
Undistributed earnings, diluted	<u>0.23</u>	<u>0.23</u>
Total	<u>\$ 0.65</u>	<u>\$ 0.62</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.

EXHIBIT 12.1
PACIFIC GAS AND ELECTRIC COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Three Months Ended March 31,	Year Ended December 31,				
	2009	2008	2007	2006	2005	2004
Earnings:						
Net income	\$ 239	\$ 1,199	\$ 1,024	\$ 985	\$ 934	\$ 3,982
Adjustments for minority interest in losses of less than 100% owned affiliates and the Company's equity in undistributed income (losses) of less than 50% owned affiliates	-	-	-	-	-	-
Income taxes provision	131	488	571	602	574	2,561
Net fixed charges	216	772	889	801	589	671
Total Earnings	\$ 586	\$ 2,459	\$ 2,484	\$ 2,388	\$ 2,097	\$ 7,214
Fixed Charges:						
Interest on short-term borrowings and long-term debt, net	\$ 199	\$ 794	\$ 834	\$ 770	\$ 573	\$ 682
Interest on capital leases	5	22	23	11	1	1
AFUDC debt	12	(44)	32	20	15	(12)
Earnings required to cover the preferred stock dividend and preferred security distribution requirements of majority owned trust	-	-	-	-	-	-
Total Fixed Charges	\$ 216	\$ 772	\$ 889	\$ 801	\$ 589	\$ 671
Ratios of Earnings to Fixed Charges	2.71	3.19	2.79	2.98	3.56	10.75

Note:

For the purpose of computing Pacific Gas and Electric Company's ratios of earnings to fixed charges, "earnings" represent net income adjusted for the minority interest in losses of less than 100% owned affiliates, equity in undistributed income or losses of less than 50% owned affiliates, 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, AFUDC debt, and earnings required to cover the preferred stock dividends. Fixed charges exclude interest on tax liabilities in accordance with FASB Interpretation No. 48 (Accounting for Uncertainty in Income Taxes).

EXHIBIT 12.2
PACIFIC GAS AND ELECTRIC COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO COMBINED
FIXED CHARGES AND PREFERRED STOCK DIVIDENDS

	Three Month Ended March 31,	Year Ended December 31,				
	2009	2008	2007	2006	2005	2004
Earnings:						
Net income	\$ 239	\$ 1,199	\$ 1,024	\$ 985	\$ 934	\$ 3,982
Adjustments for minority interest in losses of less than 100% owned affiliates and the Company's equity in undistributed income (losses) of less than 50% owned affiliates	-	-	-	-	-	-
Income taxes provision	131	488	571	602	574	2,561
Net fixed charges	216	772	889	801	589	671
Total Earnings	\$ 586	\$ 2,459	\$ 2,484	\$ 2,388	\$ 2,097	\$ 7,214
Fixed Charges:						
Interest on short-term borrowings and long-term debt, net	\$ 199	\$ 794	\$ 834	\$ 770	\$ 573	\$ 682
Interest on capital leases	5	22	23	11	1	1
AFUDC debt	12	(44)	32	20	15	(12)
Earnings required to cover the preferred stock dividend and preferred security distribution requirements of majority owned trust	-	-	-	-	-	-
Total Fixed Charges	\$ 216	\$ 772	\$ 889	\$ 801	\$ 589	\$ 671
Preferred Stock Dividends:						
Tax deductible dividends	2	9	9	12	12	9
Pre-tax earnings required to cover non-tax deductible preferred stock dividend requirements	2	7	8	3	13	34
Total Preferred Stock Dividends	4	16	17	15	25	43
Total Combined Fixed Charges and Preferred Stock Dividends	\$ 220	\$ 788	\$ 906	\$ 816	\$ 614	\$ 714
Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends						
	2.66	3.12	2.74	2.93	3.42	10.10

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 net income adjusted for the minority interest in losses of less than 100% owned affiliates, equity in undistributed income or losses of less than 50% owned affiliates, 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, AFUDC debt, and earnings required to cover preferred stock dividends. "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).

EXHIBIT 12.3
PG&E CORPORATION
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Three Months Ended March 31,	Year Ended December 31,				
	2009	2008	2007	2006	2005	2004
Earnings:						
Net income	\$ 244	\$ 1,338	\$ 1,006	\$ 991	\$ 917	\$ 4,504
Adjustments for minority interest in losses of less than 100% owned affiliates and the Company's equity in undistributed income (losses) of less than 50% owned affiliates	-	-	-	-	-	-
Income taxes provision	115	425	539	554	544	2,466
Net fixed charges	225	803	920	830	619	802
Total Earnings	\$ 584	\$ 2,566	\$ 2,465	\$ 2,375	\$ 2,080	\$ 7,772
Fixed Charges:						
Interest on short-term borrowings and long-term debt, net	\$ 208	\$ 825	\$ 865	\$ 799	\$ 603	\$ 813
Interest on capital leases	5	22	23	11	1	1
AFUDC debt	12	(44)	32	20	15	(12)
Earnings required to cover the preferred stock dividend and preferred security distribution requirements of majority owned trust	-	-	-	-	-	-
Total Fixed Charges	\$ 225	\$ 803	\$ 920	\$ 830	\$ 619	\$ 802
Ratios of Earnings to Fixed Charges	2.60	3.20	2.68	2.86	3.36	9.69

Note:

For the purpose of computing PG&E Corporation's ratios of earnings to fixed charges, "earnings" represent net income adjusted for the minority interest in losses of less than 100% owned affiliates, equity in undistributed income or losses of less than 50% owned affiliates, 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, AFUDC debt, and earnings required to cover the preferred stock dividends. Fixed charges exclude interest on tax liabilities in accordance with FASB Interpretation No. 48 (Accounting for Uncertainty in Income Taxes).

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 March 31, 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: May 6, 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, Christopher P. Johns, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarter ended March 31, 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: May 6, 2009

CHRISTOPHER P. JOHNS

Christopher P. Johns

Senior Vice President, Chief Financial Officer

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 March 31, 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: May 6, 2009

PETER A. DARBEE

Peter A. Darbee

President and Chief Executive Officer

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 March 31, 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: May 6, 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 March 31, 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

May 6, 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 March 31, 2009 ("Form 10-Q"), I, Christopher P. Johns, Senior Vice President, 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.

CHRISTOPHER P. JOHNS

CHRISTOPHER P. JOHNS

Senior Vice President,
Chief Financial Officer

May 6, 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 March 31, 2009 ("Form 10-Q"), I, Peter A. Darbee, President and Chief Executive 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.

PETER A. DARBEE

PETER A. DARBEE

President and Chief Executive Officer

May 6, 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 March 31, 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

May 6, 2009