

PG&E CORP

FORM 10-Q (Quarterly Report)

Filed 11/06/08 for the Period Ending 09/30/08

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

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

(Mark One)

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

For the quarterly period ended September 30, 2008

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) have been subject to such filing requirements for the past 90 days. ☒ Yes ☐ No

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

PG&E Corporation:	☒ Large accelerated filer	☐ Accelerated Filer
	☐ Non-accelerated filer	☐ Smaller reporting company
Pacific Gas and Electric Company:	☐ Large accelerated filer	☐ Accelerated Filer
	☒ Non-accelerated filer	☐ Smaller reporting company

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

PG&E Corporation: ☐ Yes ☒ No

Pacific Gas and Electric Company: ☐ Yes ☒ No

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

Common Stock Outstanding as of October 31, 2008:

PG&E Corporation	360,983,933
Pacific Gas and Electric Company	264,374,809

**PG&E CORPORATION AND
PACIFIC GAS AND ELECTRIC COMPANY,
FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2008
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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		Nine Months Ended	
	September 30,		September 30,	
	2008	2007	2008	2007
Operating Revenues				
Electric	\$ 2,880	\$ 2,574	\$ 8,039	\$ 7,107
Natural gas	794	705	2,946	2,714
Total operating revenues	3,674	3,279	10,985	9,821
Operating Expenses				
Cost of electricity	1,282	998	3,406	2,606
Cost of natural gas	351	281	1,613	1,431
Operating and maintenance	983	953	3,010	2,794
Depreciation, amortization, and decommissioning	419	465	1,240	1,325
Total operating expenses	3,035	2,697	9,269	8,156
Operating Income	639	582	1,716	1,665
Interest income	23	36	82	125
Interest expense	(178)	(196)	(550)	(571)
Other income (expense), net	(17)	7	(14)	22
Income Before Income Taxes	467	429	1,234	1,241
Income tax provision	163	151	413	438
Net Income	\$ 304	\$ 278	\$ 821	\$ 803
Weighted Average Common Shares Outstanding, Basic	357	352	356	350
Weighted Average Common Shares Outstanding, Diluted	358	353	357	352
Net Earnings Per Common Share, Basic	\$ 0.83	\$ 0.77	\$ 2.25	\$ 2.23
Net Earnings Per Common Share, Diluted	\$ 0.83	\$ 0.77	\$ 2.24	\$ 2.22
Dividends Declared Per Common Share	\$ 0.39	\$ 0.36	\$ 1.17	\$ 1.08

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions)	(Unaudited)	
	Balance At	
	September 30, 2008	December 31, 2007
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 251	\$ 345
Restricted cash	1,325	1,297
Accounts receivable:		
Customers (net of allowance for doubtful accounts of \$75 million in 2008 and \$58 million in 2007)	2,530	2,349
Regulatory balancing accounts	1,117	771
Inventories:		
Gas stored underground and fuel oil	333	205
Materials and supplies	172	166
Income taxes receivable	-	61
Prepaid expenses and other	580	255
Total current assets	6,308	5,449
Property, Plant, and Equipment		
Electric	27,146	25,599
Gas	10,016	9,620
Construction work in progress	1,668	1,348
Other	16	17
Total property, plant, and equipment	38,846	36,584
Accumulated depreciation	(13,422)	(12,928)
Net property, plant, and equipment	25,424	23,656
Other Noncurrent Assets		
Regulatory assets	4,233	4,459
Nuclear decommissioning funds	1,819	1,979
Other	1,094	1,089
Total other noncurrent assets	7,146	7,527
TOTAL ASSETS	\$ 38,878	\$ 36,632

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited)	
	Balance At	
	September 30, 2008	December 31, 2007
(in millions, except share amounts)		
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	\$ 1,335	\$ 519
Long-term debt, classified as current	600	-
Energy recovery bonds, classified as current	366	354
Accounts payable:		
Trade creditors	962	1,067
Disputed claims and customer refunds	1,588	1,629
Regulatory balancing accounts	906	673
Other	385	394
Interest payable	708	697
Income taxes payable	116	-
Deferred income taxes	156	-
Other	1,375	1,374
Total current liabilities	8,497	6,707
Noncurrent Liabilities		
Long-term debt	7,816	8,171
Energy recovery bonds	1,310	1,582
Regulatory liabilities	4,456	4,448
Asset retirement obligations	1,628	1,579
Income taxes payable	231	234
Deferred income taxes	3,383	3,053
Deferred tax credits	95	99
Other	2,071	1,954
Total noncurrent liabilities	20,990	21,120
Commitments and Contingencies		
Preferred Stock of Subsidiaries	252	252
Preferred Stock		
Preferred stock, no par value, authorized 80,000,000 shares, \$100 par value, authorized 5,000,000 shares, none issued	-	-
Common Shareholders' Equity		
Common stock, no par value, authorized 800,000,000 shares, issued 358,198,735 common and 1,315,818 restricted shares in 2008 and issued 378,385,151 common and 1,261,125 restricted shares in 2007	5,883	6,110
Common stock held by subsidiary, at cost, 24,665,500 shares in 2007	-	(718)
Reinvested earnings	3,238	3,151
Accumulated other comprehensive income	18	10
Total common shareholders' equity	9,139	8,553
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	\$ 38,878	\$ 36,632

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)	(Unaudited)	
	Nine Months Ended September 30,	
	2008	2007
Cash Flows From Operating Activities		
Net income	\$ 821	\$ 803
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, decommissioning, and allowance for equity funds used during construction	1,337	1,419
Deferred income taxes and tax credits, net	482	(33)
Other changes in noncurrent assets and liabilities	87	281
Gain on sale of assets	(1)	(1)
Effect of changes in operating assets and liabilities:		
Accounts receivable	(181)	(80)
Inventories	(153)	(92)
Accounts payable	(100)	(322)
Income taxes receivable/payable	177	234
Regulatory balancing accounts, net	(94)	(238)
Other current assets	(123)	120
Other current liabilities	(68)	19
Other	(2)	(32)
Net cash provided by operating activities	2,182	2,078
Cash Flows From Investing Activities		
Capital expenditures	(2,691)	(2,035)
Proceeds from sale of assets	21	15
Increase in restricted cash	(3)	(32)
Proceeds from nuclear decommissioning trust sales	1,121	703
Purchases of nuclear decommissioning trust investments	(1,161)	(805)
Money market investments (see Note 8)	(62)	-
Net cash used in investing activities	(2,775)	(2,154)
Cash Flows From Financing Activities		
Borrowings under accounts receivable facility and working capital facility	533	600
Repayments under accounts receivable facility and working capital facility	(250)	(300)
Net issuance of commercial paper, net of \$9 million discount in 2008 and \$2 million in 2007	524	91
Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of \$2 million in 2008 and \$10 million in 2007	693	690
Long-term debt repurchased	(454)	-
Rate reduction bonds matured	-	(217)
Energy recovery bonds matured	(260)	(251)
Common stock issued	150	120
Common stock dividends paid	(406)	(367)
Other	(31)	38
Net cash provided by financing activities	499	404
Net change in cash and cash equivalents	(94)	328
Cash and cash equivalents at January 1	345	456
Cash and cash equivalents at September 30	\$ 251	\$ 784
Supplemental disclosures of cash flow information		
Cash paid for:		
Interest (net of amounts capitalized)	\$ 449	\$ 443
Income taxes paid (refunded), net	(146)	307
Supplemental disclosures of noncash investing and financing activities		
Common stock dividends declared but not yet paid	\$ 140	\$ 127
Capital expenditures financed through accounts payable	224	170

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		Nine Months Ended	
	September 30,		September 30,	
	2008	2007	2008	2007
Operating Revenues				
Electric	\$ 2,880	\$ 2,574	\$ 8,039	\$ 7,107
Natural gas	794	705	2,946	2,714
Total operating revenues	<u>3,674</u>	<u>3,279</u>	<u>10,985</u>	<u>9,821</u>
Operating Expenses				
Cost of electricity	1,282	998	3,406	2,606
Cost of natural gas	351	281	1,613	1,431
Operating and maintenance	982	950	3,009	2,788
Depreciation, amortization, and decommissioning	419	465	1,239	1,325
Total operating expenses	<u>3,034</u>	<u>2,694</u>	<u>9,267</u>	<u>8,150</u>
Operating Income	<u>640</u>	<u>585</u>	<u>1,718</u>	<u>1,671</u>
Interest income	20	33	77	116
Interest expense	(170)	(189)	(528)	(549)
Other income (expense), net	(2)	13	24	38
Income Before Income Taxes	<u>488</u>	<u>442</u>	<u>1,291</u>	<u>1,276</u>
Income tax provision	167	159	421	458
Net Income	<u>321</u>	<u>283</u>	<u>870</u>	<u>818</u>
Preferred stock dividend requirement	3	4	10	10
Income Available for Common Stock	<u>\$ 318</u>	<u>\$ 279</u>	<u>\$ 860</u>	<u>\$ 808</u>

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited)	
	Balance At	
	September	December
(in millions)	30,	31, 2007
	2008	
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 57	\$ 141
Restricted cash	1,325	1,297
Accounts receivable:		
Customers (net of allowance for doubtful accounts of \$75 million in 2008 and \$58 million in 2007)	2,530	2,349
Related parties	-	6
Regulatory balancing accounts	1,117	771
Inventories:		
Gas stored underground and fuel oil	333	205
Materials and supplies	172	166
Income taxes receivable	-	15
Prepaid expenses and other	517	252
Total current assets	6,051	5,202
Property, Plant, and Equipment		
Electric	27,146	25,599
Gas	10,016	9,620
Construction work in progress	1,668	1,348
Total property, plant, and equipment	38,830	36,567
Accumulated depreciation	(13,407)	(12,913)
Net property, plant, and equipment	25,423	23,654
Other Noncurrent Assets		
Regulatory assets	4,233	4,459
Nuclear decommissioning funds	1,819	1,979
Related parties receivable	27	23
Other	1,011	993
Total other noncurrent assets	7,090	7,454
TOTAL ASSETS	\$ 38,564	\$ 36,310

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited)	
	Balance At	
	September 30, 2008	December 31, 2007
(in millions, except share amounts)		
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	\$ 1,335	\$ 519
Long-term debt, classified as current	600	-
Energy recovery bonds, classified as current	366	354
Accounts payable:		
Trade creditors	962	1,067
Disputed claims and customer refunds	1,588	1,629
Related parties	33	28
Regulatory balancing accounts	906	673
Other	371	370
Interest payable	701	697
Income taxes payable	193	-
Deferred income taxes	161	4
Other	1,185	1,200
Total current liabilities	8,401	6,541
Noncurrent Liabilities		
Long-term debt	7,536	7,891
Energy recovery bonds	1,310	1,582
Regulatory liabilities	4,456	4,448
Asset retirement obligations	1,628	1,579
Income taxes payable	82	103
Deferred income taxes	3,421	3,104
Deferred tax credits	95	99
Other	1,974	1,838
Total noncurrent liabilities	20,502	20,644
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 2008 and issued 282,916,485 shares in 2007	1,322	1,415
Common stock held by subsidiary, at cost, 19,481,213 shares in 2007	-	(475)
Additional paid-in capital	2,150	2,220
Reinvested earnings	5,910	5,694
Accumulated other comprehensive income	21	13
Total shareholders' equity	9,661	9,125
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	\$ 38,564	\$ 36,310

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)	(Unaudited)	
	Nine Months Ended September 30,	
	2008	2007
Cash Flows From Operating Activities		
Net income	\$ 870	\$ 818
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, decommissioning, and allowance for equity funds used during construction	1,337	1,417
Deferred income taxes and tax credits, net	470	(35)
Other changes in noncurrent assets and liabilities	55	270
Gain on sale of assets	(1)	(1)
Effect of changes in operating assets and liabilities:		
Accounts receivable	(179)	(82)
Inventories	(153)	(92)
Accounts payable	(85)	(315)
Income taxes receivable/payable	208	228
Regulatory balancing accounts, net	(94)	(238)
Other current assets	(125)	120
Other current liabilities	(80)	35
Other	(3)	(32)
Net cash provided by operating activities	2,220	2,093
Cash Flows From Investing Activities		
Capital expenditures	(2,691)	(2,035)
Proceeds from sale of assets	21	15
Increase in restricted cash	(3)	(32)
Proceeds from nuclear decommissioning trust sales	1,121	703
Purchases of nuclear decommissioning trust investments	(1,161)	(805)
Net cash used in investing activities	(2,713)	(2,154)
Cash Flows From Financing Activities		
Borrowings under accounts receivable facility and working capital facility	533	600
Repayments under accounts receivable facility and working capital facility	(250)	(300)
Net issuance of commercial paper, net of discount of \$9 million in 2008 and \$2 million in 2007	524	91
Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of \$2 million in 2008 and \$10 million in 2007	693	690
Long-term debt repurchased	(454)	-
Rate reduction bonds matured	-	(217)
Energy recovery bonds matured	(260)	(251)
Equity contribution	90	200
Common stock dividends paid	(426)	(381)
Preferred stock dividends paid	(10)	(10)
Other	(31)	29
Net cash provided by financing activities	409	451
Net change in cash and cash equivalents	(84)	390
Cash and cash equivalents at January 1	141	70
Cash and cash equivalents at September 30	\$ 57	\$ 460
Supplemental disclosures of cash flow information		
Cash paid for:		
Interest (net of amounts capitalized)	\$ 436	\$ 416
Income taxes paid (refunded), net	(138)	403
Supplemental disclosures of noncash investing and financing activities		
Capital expenditures financed through accounts payable	\$ 224	\$ 170

See accompanying Notes to the Condensed Consolidated Financial Statements.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

NOTE 1: ORGANIZATION AND BASIS OF PRESENTATION

PG&E Corporation is a holding company whose primary purpose is to hold interests in energy-based businesses. PG&E Corporation conducts its business principally through Pacific Gas and Electric Company ("Utility"), a public utility operating in northern and central California. The Utility engages in the businesses of electricity and natural gas distribution; electricity generation, procurement, and transmission; and natural gas procurement, transportation, and storage. The Utility is 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 that the Utility is required to consolidate under applicable accounting standards and 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 accounting principles generally accepted 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. The information at December 31, 2007 in both PG&E Corporation 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, 2007. PG&E Corporation and the Utility's combined Annual Report on Form 10-K for the year ended December 31, 2007, together with the information incorporated by reference into such report, is referred to in this Quarterly Report on Form 10-Q as the "2007 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 2007 Annual Report.

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions. These estimates and assumptions affect the reported amounts of revenues, expenses, assets and liabilities, the disclosure of contingencies, and include, but are not limited to, estimates and assumptions used in determining the Utility's regulatory asset and liability balances based on probability assessments of regulatory recovery, revenues earned but not yet billed, the remaining disputed claims made by electricity suppliers in the Utility's proceeding under Chapter 11 of the U.S. Bankruptcy Code ("Chapter 11") and customer refunds, asset retirement obligations ("ARO"), allowance for doubtful accounts receivable, provisions for losses that are deemed probable from environmental remediation liabilities, pension and other employee benefit plan assets and liabilities, liabilities for future severance costs, accounting for derivatives under Statement of Financial Accounting Standards ("SFAS") No. 133 "Accounting for Derivative Instruments and Hedging Activities" ("SFAS No. 133"), fair value measurements under SFAS No. 157 "Fair Value Measurements" ("SFAS No. 157"), income tax-related assets and liabilities, and accruals for legal matters. In addition, the Utility uses estimates and assumptions when it reviews long-lived assets and certain identifiable intangibles that are held and used in operations for impairment. (A review is triggered whenever events or changes in circumstances indicate that the carrying amount of these assets might not be recoverable.) A change in management's estimates or assumptions could have a material impact on PG&E Corporation and the Utility's financial condition and results of operations during the period in which such change occurred. As these estimates and assumptions involve judgments on a wide range of factors, including future regulatory decisions and economic conditions that are difficult to predict, actual results may differ materially from these estimates. PG&E Corporation and the Utility's Condensed Consolidated Financial Statements reflect all adjustments management believes are necessary for the fair presentation of their financial condition and results of operations for the periods presented. Interim period results of operations are not necessarily indicative of the results of operations for the full year.

This quarterly report should be read in conjunction with PG&E Corporation and the Utility's audited Consolidated Financial Statements and Notes to the Consolidated Financial Statements in the 2007 Annual Report.

NOTE 2: NEW AND SIGNIFICANT ACCOUNTING POLICIES

Fair Value Measurements

On January 1, 2008, PG&E Corporation and the Utility adopted the provisions of SFAS No. 157, which defines fair value, establishes criteria when measuring fair value, and expands disclosures about fair value measurements. SFAS No. 157 defines fair value as “the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date,” or the “exit price.” Accordingly, an entity must now determine the fair value of an asset or liability based on the assumptions that market participants would use in pricing the asset or liability, not those of the reporting entity itself. Additionally, SFAS No. 157 establishes a fair value hierarchy, which gives precedence to fair value measurements, calculated using observable inputs to those using unobservable inputs. SFAS No. 157 requires entities to disclose fair-valued financial instruments according to the hierarchy in each reporting period after implementation. The provisions of SFAS No. 157 have been deferred to fiscal years beginning after November 15, 2008 for nonrecurring, nonfinancial instruments shown at fair value. See Note 8 of the Notes to the Condensed Consolidated Financial Statements for further discussion and financial statement impact of the implementation of SFAS No. 157.

Fair Value Option

On January 1, 2008, PG&E Corporation and the Utility adopted the provisions of SFAS No. 159, “The Fair Value Option for Financial Assets and Financial Liabilities” (“SFAS No. 159”). SFAS No. 159 establishes a fair value option under which entities can elect to report certain financial assets and liabilities at fair value with changes in fair value recognized in earnings. PG&E Corporation and the Utility have not elected the fair value option for any assets or liabilities as of and during the three and nine months ended September 30, 2008; therefore, the adoption of SFAS No. 159 did not impact the Condensed Consolidated Financial Statements.

Amendment of Financial Accounting Standards Board Interpretation No. 39

On January 1, 2008, PG&E Corporation and the Utility adopted the provisions of Financial Accounting Standards Board (“FASB”) Staff Position on Interpretation 39, “Amendment of FASB Interpretation No. 39” (“FIN 39-1”). Under FIN 39-1, a reporting entity is required to offset the cash collateral paid or cash collateral received against the fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement when reporting those amounts on a net basis. The provisions of FIN 39-1 are applied retrospectively. See Note 7 of the Notes to the Condensed Consolidated Financial Statements for further discussion and financial statement impact of the implementation of FIN 39-1.

Share-Based Compensation

PG&E Corporation and the Utility account for share-based compensation awards in accordance with the provisions of SFAS No. 123R, “Share-Based Payment” (“SFAS No. 123R”), using the modified prospective application method, which requires that compensation cost be recognized for all share-based payment awards, including unvested stock options, based on the grant date fair value. SFAS No. 123R requires that an estimate of future forfeitures be made and that compensation cost be recognized only for share-based payment awards that are expected to vest.

PG&E Corporation and the Utility use an estimated annual forfeiture rate of 2.5%, based on historic forfeiture rates, for purposes of determining compensation expense for share-based incentive awards. The following table provides a summary of total compensation expense for PG&E Corporation (consolidated) and the Utility (stand-alone) for share-based incentive awards for the three and nine months ended September 30, 2008 and 2007:

(in millions)	PG&E Corporation		Utility	
	Three Months Ended		Three Months Ended	
	September 30,		September 30,	
	2008	2007	2008	2007
Stock options	\$ 1	\$ 2	\$ -	\$ 1
Restricted stock	5	6	4	4
Performance shares	-	15	-	10
Total compensation expense (pre-tax)	\$ 6	\$ 23	\$ 4	\$ 15
Total compensation expense (after-tax)	\$ 4	\$ 14	\$ 2	\$ 9

(in millions)	PG&E Corporation		Utility	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Stock options	\$ 2	\$ 6	\$ 1	\$ 3
Restricted stock	19	19	13	12
Performance shares	8	15	5	9
Total compensation expense (pre-tax)	\$ 29	\$ 40	\$ 19	\$ 24
Total compensation expense (after-tax)	\$ 17	\$ 24	\$ 11	\$ 14

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.

Net periodic benefit cost as reflected in PG&E Corporation's Condensed Consolidated Statements of Income for the three and nine months ended September 30, 2008 and 2007 are as follows:

(in millions)	Pension Benefits		Other Benefits	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2008	2007	2008	2007
Service cost for benefits earned	\$ 59	\$ 55	\$ 7	\$ 7
Interest cost	148	139	21	20
Expected return on plan assets	(173)	(178)	(22)	(23)
Amortization of transition obligation ⁽¹⁾	-	-	6	7
Amortization of prior service cost ⁽¹⁾	12	12	4	3
Amortization of unrecognized gain/(loss) ⁽¹⁾	1	1	(3)	(1)
Net periodic benefit cost	\$ 47	\$ 29	\$ 13	\$ 13

⁽¹⁾ In 2007, 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)” (“SFAS No. 158”), 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 liability in accordance with SFAS No. 71, “Accounting for the Effects of Certain Types of Regulation,” as amended (“SFAS No. 71”).

(in millions)	Pension Benefits		Other Benefits	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Service cost for benefits earned	\$ 177	\$ 173	\$ 22	\$ 22
Interest cost	436	408	61	59
Expected return on plan assets	(522)	(533)	(70)	(72)
Amortization of transition obligation ⁽¹⁾	-	-	19	19
Amortization of prior service cost ⁽¹⁾	35	37	12	12
Amortization of unrecognized gain/(loss) ⁽¹⁾	1	2	(11)	(7)
Net periodic benefit cost	\$ 127	\$ 87	\$ 33	\$ 33

⁽¹⁾ In 2007, under SFAS No.158, 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 liability in accordance with SFAS No. 71.

There was no material difference between PG&E Corporation and the Utility's consolidated net periodic benefit costs.

Accounting Pronouncements Issued But Not Yet Adopted

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

In March 2008, the FASB issued 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. An entity is required to provide qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures on fair value amounts of and gains and losses on derivative instruments, and disclosures relating to credit-risk-related contingent features in derivative agreements. SFAS No. 161 is effective prospectively for fiscal years beginning after November 15, 2008. PG&E Corporation and the Utility are currently evaluating the impact of SFAS No. 161.

NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

PG&E Corporation and the Utility account 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.

Under SFAS No. 71, incurred costs that would otherwise be charged to expense may be capitalized and recorded as regulatory assets if it is probable that the incurred costs will be recovered in future rates. The regulatory assets are amortized over future periods consistent with the inclusion of costs in authorized customer rates. If costs that a regulated enterprise expects to incur in the future are currently being recovered through rates, SFAS No. 71 requires that the regulated enterprise record those expected future costs as regulatory liabilities. In addition, amounts that are probable of being credited or refunded to customers in the future must be recorded as regulatory liabilities.

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

Regulatory Assets

Long-term regulatory assets are comprised of the following:

(in millions)	Balance At	
	September 30, 2008	December 31, 2007
Energy recovery bond regulatory asset	\$ 1,571	\$ 1,833
Regulatory assets for deferred income tax	827	732
Utility retained generation regulatory assets	817	947
Environmental compliance costs	375	328
Unamortized loss, net of gain, on reacquired debt	223	269
Regulatory assets associated with plan of reorganization	108	122
Contract termination costs	86	96
Scheduling coordinator costs	66	90
Other	160	42
Total regulatory assets	<u>\$ 4,233</u>	<u>\$ 4,459</u>

The energy recovery bond (“ERB”) regulatory asset represents the refinancing of the settlement regulatory asset established under the December 19, 2003 settlement agreement among PG&E Corporation, the Utility, and the CPUC to resolve the Utility’s Chapter 11 proceeding (“Chapter 11 Settlement Agreement”). The Utility expects to fully recover this asset by the end of 2012.

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

In connection with the Chapter 11 Settlement Agreement, the Utility recognized a one-time non-cash gain of \$1.2 billion related to the recovery of the Utility's retained generation regulatory assets in 2004. The individual components of these regulatory assets are amortized over approximately 16 years.

Environmental compliance costs represent the portion of estimated environmental remediation liabilities that the Utility expects to recover in future rates as actual remediation costs are incurred. The Utility expects to recover these costs over periods ranging from 1 to 30 years.

Unamortized loss, net of gain, on reacquired debt represents costs related to debt reacquired or redeemed prior to maturity with associated discount and debt issuance costs. These costs are expected to be recovered over the remaining original amortization period of the reacquired debt over periods ranging from 1 to 18 years.

Regulatory assets associated with the Utility's plan of reorganization include costs incurred in financing the Utility's plan of reorganization under Chapter 11 and costs to oversee the environmental enhancement projects of the Pacific Forest and Watershed Stewardship Council, an entity that was established pursuant to the Utility's plan of reorganization. The Utility expects to recover these costs over periods ranging from 5 to 30 years.

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

The regulatory asset related to scheduling coordinator ("SC") costs represents costs that the Utility incurred beginning in 1998 in its capacity as an SC for its then existing wholesale transmission customers. The Utility expects to fully recover the SC costs by the fourth quarter of 2009.

"Other" is primarily related to price risk management regulatory assets. The Utility enters into contracts to procure electricity and natural gas that are designed to reduce commodity price risks. Some of these price risk management contracts are accounted for as derivative instruments under SFAS No. 133 (see Note 7 of the Notes to the Condensed Consolidated Financial Statements). Changes in the fair value of derivative instruments are recognized as price risk management assets or liabilities. The unrealized gain or loss associated with changes in the fair value of these derivative instruments is deferred and recorded in regulatory accounts to be recovered or refunded through regulated rates. Price risk management regulatory assets represent the deferral of unrealized losses related to price risk management derivative instruments with terms in excess of one year.

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

Current Regulatory Assets

At September 30, 2008 and December 31, 2007, the Utility had current regulatory assets of approximately \$317 million and \$131 million, respectively, consisting primarily of price risk management regulatory assets and the current portion of long-term 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 are comprised of the following:

(in millions)	Balance At	
	September 30, 2008	December 31, 2007
Cost of removal obligation	\$ 2,694	\$ 2,568
Employee benefit plans	626	578
Asset retirement costs	335	573
Public purpose programs	318	264
California Solar Initiative	206	159
Price risk management	105	124
Other	172	182
Total regulatory liabilities	<u>\$ 4,456</u>	<u>\$ 4,448</u>

Cost of removal liabilities represent revenues collected for asset removal costs that the Utility expects to incur in the future.

Employee benefit plan expenses represent the cumulative differences between amounts recognized in accordance with GAAP and amounts recognized for ratemaking purposes, which also includes amounts that otherwise would be fully recorded to Accumulated other comprehensive income in the Condensed Consolidated Balance Sheets in accordance with SFAS No. 158. (See Note 2 of the Notes to the Condensed Consolidated Financial Statements and the 2007 Annual Report for further discussion.) These balances will be charged against expense to the extent that future expenses exceed amounts recoverable for regulatory purposes.

Asset retirement costs represent timing differences between the recognition of ARO in accordance with GAAP and the amounts recognized for ratemaking purposes.

Public purpose program liabilities represent revenues designated for public purpose program costs that are expected to be incurred in the future.

California Solar Initiative liabilities represent revenues collected from customers to pay for costs the Utility expects to incur in the future to promote the use of solar energy in residential homes and commercial, industrial, and agricultural properties.

Price risk management regulatory liabilities represent the deferral of unrealized gains related to price risk management derivative instruments with terms in excess of one year.

“Other” is primarily related to amounts received from insurance companies to pay for hazardous substance remediation costs. The insurance recoveries are refunded to customers as a reduction to rates until customers are fully reimbursed for the cost of hazardous substance remediation that has been collected in rates. Additionally, “Other” includes regulatory liabilities that represent future customer benefits associated with the Gateway Generating Station (“Gateway”). Gateway was acquired as part of a settlement with Mirant Corporation and the associated liability will be amortized over 30 years beginning in January 2009 when Gateway is anticipated to be placed in service.

Current Regulatory Liabilities

As of September 30, 2008, the Utility had current regulatory liabilities of approximately \$310 million, consisting primarily of price risk management regulatory liabilities representing the deferral of unrealized gains related to price risk management derivative instruments with terms of less than one year. As of December 31, 2007, the Utility had current regulatory liabilities of approximately \$280 million, 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 revenues and the Utility's authorized revenue requirements and cost regulatory balancing accounts to accumulate differences between incurred costs and costs recovered, or collected (primarily commodity cost). 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 Sheet. The CPUC does not allow the Utility to offset regulatory balancing account assets against regulatory balancing account liabilities.

Current Regulatory Balancing Account Assets

	Balance At	
	September 30, 2008	December 31, 2007
(in millions)		
Electricity revenue and cost balancing accounts	\$ 1,059	\$ 678
Natural gas revenue and cost balancing accounts	58	93
Total	<u>\$ 1,117</u>	<u>\$ 771</u>

Current Regulatory Balancing Account Liabilities

	Balance At	
	September 30, 2008	December 31, 2007
(in millions)		
Electricity revenue and cost balancing accounts	\$ 795	\$ 618
Natural gas revenue and cost balancing accounts	111	55
Total	<u>\$ 906</u>	<u>\$ 673</u>

During the nine months ended September 30, 2008, the under-collection in the Utility's electricity revenue and cost balancing accounts increased from December 31, 2007. This change is primarily due to higher than forecasted procurement costs. During the nine months ended September 30, 2008, the over-collection in the Utility's natural gas revenue and cost balancing accounts increased from December 31, 2007 mainly due to seasonal demand changes.

NOTE 4: DEBT

PG&E Corporation

Convertible Subordinated Notes

At September 30, 2008, PG&E Corporation had outstanding approximately \$280 million of 9.50% Convertible Subordinated Notes that are scheduled to mature on June 30, 2010. Interest is payable semi-annually in arrears on June 30 and December 31. These Convertible Subordinated Notes may be converted (at the option of the holder) at any time prior to maturity into 18,558,059 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 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, 2008, PG&E Corporation has paid "pass-through dividends" totaling approximately \$28 million, including \$7 million paid on October 15, 2008.

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. Dividend participation rights are recognized as operating cash flows in PG&E Corporation's Condensed Consolidated Statements of Cash Flows. Changes in the fair value are recognized (in Other income (expense), net) in PG&E Corporation's Condensed Consolidated Statements of Income as a non-operating expense or income. At September 30, 2008, the total estimated fair value of the dividend participation rights, on a pre-tax basis, was approximately \$49 million, of which \$28 million was classified in Current Liabilities - Other and \$21 million was classified in Noncurrent Liabilities - Other in the accompanying Condensed Consolidated Balance Sheets. At December 31, 2007, the total estimated fair value of the dividend participation rights, on a pre-tax basis, was approximately \$62 million, of which \$25 million was classified in Current Liabilities - Other and \$37 million was classified in Noncurrent Liabilities - Other in the accompanying Condensed Consolidated Balance Sheets. The discount factor used to value these rights was adjusted on January 1, 2008 in order to comply with the provisions of SFAS No. 157, resulting in a \$6 million increase in fair value. (See Note 8 of the Notes to the Condensed Consolidated Financial Statements for further discussion of the implementation of SFAS No. 157.)

Utility

Senior Notes

On March 3, 2008, the Utility issued \$200 million principal amount of 5.625% Senior Notes due on November 30, 2017, increasing the total outstanding amount of 5.625% Senior Notes to \$700 million. Also on March 3, 2008, the Utility issued \$400 million principal amount of 6.35% Senior Notes due on February 15, 2038.

At September 30, 2008, there were \$6.9 billion of senior notes outstanding.

On October 21, 2008, the Utility issued \$600 million principal amount of 8.25% 10-year Senior Notes due on October 15, 2018.

Pollution Control Bonds

The California Pollution Control Financing Authority and the California Infrastructure and Economic Development Bank ("CIEDB") have issued various series of tax-exempt pollution control bonds for the benefit of the Utility.

In 2005, the Utility purchased financial guaranty insurance policies to insure the regularly scheduled payments on \$454 million of pollution control bonds series 2005 A-G ("PC2005 bonds") issued by the CIEDB. Interest rates on these bonds were set at auction every 7 or 35 days. In January 2008, the insurer's credit rating was downgraded and/or put on review for possible downgrade by several credit agencies. This, in addition to credit issues that impacted the auction rate securities markets, resulted in increases in interest rates for the PC2005 bonds. To eliminate this interest rate risk, the Utility repurchased \$300 million of the PC2005 bonds in March 2008 and the remaining \$154 million in April 2008.

On September 22, 2008, the CIEDB issued \$50 million principal amount of pollution control bonds series F due on November 1, 2026 and \$45 million principal amount of pollution control bonds series G due on December 1, 2018 for the benefit of the Utility. These series of bonds refunded the corresponding related series of PC2005 bonds. Each series of bonds will bear interest at 3.75% per year through September 19, 2010 and is subject to mandatory tender on September 20, 2010 at a price of 100% of the principal amount plus accrued interest. Thereafter, these series of bonds may be remarketed in a fixed or variable rate mode. Interest is payable semi-annually in arrears on March 1 and September 1.

At September 30, 2008, there were \$1.3 billion of pollution control bonds outstanding.

On October 29, 2008, the CIEDB issued four series of tax-exempt pollution control bonds in the principal amount of \$309 million for the benefit of the Utility. These series of bonds refunded the corresponding related series of PC2005 bonds. The bonds bear interest at variable interest rates not to exceed 12% per year. The initial interest rate on the bonds is 1.75%. The interest rate payable on the bonds will initially be reset weekly. Bonds in the principal amount of \$160 million will mature in 2016 and bonds in the principal amount of \$149 million will mature in 2026.

Each series of bonds issued in October is supported by a direct-pay letter of credit issued by Wells Fargo Bank National Association that expires on October 29, 2011, unless extended. All payments on the bonds are made through draws on the letters of credit. The Utility has entered into a reimbursement agreement with respect to each letter of credit under which the Utility is obligated to reimburse amounts drawn under such letter of credit. If the Utility does not reimburse the issuing lender for a draw on a letter of credit to pay the purchase price of tendered bonds, the Utility is deemed to have requested a loan, which loan is generally payable upon the earlier of the successful remarketing of the tendered bonds or the expiration of the letter of credit. The Utility anticipates that the refinancing of the remaining \$50 million of PC2005 bonds will occur by the end of 2008, subject to conditions in the tax-exempt bond market and the liquidity needs of the Utility.

Credit Facilities and Short-Term Borrowings

At September 30, 2008, there were approximately \$273 million of letters of credit and \$533 million of borrowings outstanding at a yield of 3.38% under the Utility's \$2.0 billion working capital facility. In addition, the working capital facility provides liquidity support for commercial paper offerings. At September 30, 2008, the Utility had \$802 million of commercial paper outstanding at an average yield of approximately 5.75%.

Energy Recovery Bonds

In furtherance of the Chapter 11 Settlement Agreement, 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 \$1.7 billion at September 30, 2008.

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: SHAREHOLDERS' EQUITY

PG&E Corporation and the Utility's changes in shareholders' equity for the nine months ended September 30, 2008 were as follows:

(in millions)	PG&E Corporation	Utility
	Total Common Shareholders' Equity	Total Shareholders' Equity
Balance at December 31, 2007	\$ 8,553	\$ 9,125
Net income	821	870
Common stock issued	150	-
Share-based compensation amortization	21	-
Common stock dividends declared and paid	(279)	(426)
Common stock dividends declared but not yet paid	(140)	-
Preferred stock dividends	-	(10)
Tax benefit from share-based payment awards	5	4
Other comprehensive income	8	8
Equity contribution	-	90
Balance at September 30, 2008	<u>\$ 9,139</u>	<u>\$ 9,661</u>

At December 31, 2007, Elm Power Corporation, a wholly owned subsidiary of PG&E Corporation, held 24,665,500 shares of PG&E Corporation common stock. Effective August 29, 2008, Elm Power Corporation was dissolved, and the shares subsequently cancelled.

At December 31, 2007, PG&E Holdings, LLC, a wholly owned subsidiary of the Utility, held approximately 7% of the Utility common stock. Effective August 29, 2008, PG&E Holdings, LLC, was dissolved, and the shares subsequently cancelled.

For the nine month period ended September 30, 2008, PG&E Corporation contributed equity of \$90 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 nine months ended September 30, 2008, the Utility paid common stock dividends totaling \$447 million, including \$426 million of common stock dividends paid to PG&E Corporation and \$21 million of common stock dividends paid to PG&E Holdings, LLC.

During the nine months ended September 30, 2008, PG&E Corporation paid common stock dividends totaling \$433 million, including \$28 million to Elm Power Corporation. On September 17, 2008, the Board of Directors of PG&E Corporation declared a dividend of \$0.39 per share, totaling \$140 million, which was paid on October 15, 2008 to shareholders of record on September 30, 2008.

During the nine months ended September 30, 2008, the Utility paid cash dividends to holders of its outstanding series of preferred stock totaling \$10 million. On September 17, 2008, the Board of Directors of the Utility declared a cash dividend on its outstanding series of preferred stock payable on November 15, 2008 to shareholders of record on October 31, 2008.

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 September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Net income	\$ 304	\$ 278	\$ 821	\$ 803
Less: distributed earnings to common shareholders	140	127	419	379
Undistributed earnings	<u>\$ 164</u>	<u>\$ 151</u>	<u>\$ 402</u>	<u>\$ 424</u>
Common shareholders earnings				
Basic				
Distributed earnings to common shareholders	\$ 140	\$ 127	\$ 419	\$ 379
Undistributed earnings allocated to common shareholders	156	143	382	402
Total common shareholders earnings, basic	<u>\$ 296</u>	<u>\$ 270</u>	<u>\$ 801</u>	<u>\$ 781</u>
Diluted				
Distributed earnings to common shareholders	\$ 140	\$ 127	\$ 419	\$ 379
Undistributed earnings allocated to common shareholders	156	143	382	402
Total common shareholders earnings, diluted	<u>\$ 296</u>	<u>\$ 270</u>	<u>\$ 801</u>	<u>\$ 781</u>
Weighted average common shares outstanding, basic	357	352	356	350
9.50% Convertible Subordinated Notes	19	19	19	19
Weighted average common shares outstanding and participating securities, basic	<u>376</u>	<u>371</u>	<u>375</u>	<u>369</u>
Weighted average common shares outstanding, basic	357	352	356	350
Employee share-based compensation	1	1	1	2
Weighted average common shares outstanding, diluted	358	353	357	352
9.50% Convertible Subordinated Notes	19	19	19	19
Weighted average common shares outstanding and participating securities, diluted	<u>377</u>	<u>372</u>	<u>376</u>	<u>371</u>
Net earnings per common share, basic				
Distributed earnings, basic ⁽¹⁾	\$ 0.39	\$ 0.36	\$ 1.18	\$ 1.08
Undistributed earnings, basic	0.44	0.41	1.07	1.15
Total	<u>\$ 0.83</u>	<u>\$ 0.77</u>	<u>\$ 2.25</u>	<u>\$ 2.23</u>
Net earnings per common share, diluted				
Distributed earnings, diluted	\$ 0.39	\$ 0.36	\$ 1.17	\$ 1.08
Undistributed earnings, diluted	0.44	0.41	1.07	1.14
Total	<u>\$ 0.83</u>	<u>\$ 0.77</u>	<u>\$ 2.24</u>	<u>\$ 2.22</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.

Options to purchase 7,285 shares of PG&E Corporation common stock were excluded from the computation of diluted EPS for the three and nine months ended September 30, 2008 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

The Utility enters into contracts to procure electricity, natural gas, nuclear fuel, and firm electricity transmission rights. Some of these contracts meet the definition of derivative instruments under SFAS No. 133. All such derivative instruments, including instruments designated as cash flow hedges, are recorded at fair value and presented as price risk management assets and liabilities on the balance sheet (see table below). As a result of applying the provisions of SFAS No. 71, unrealized changes in the fair value of derivative instruments are deferred and recorded to regulatory assets or liabilities. Under the same regulatory accounting treatment, changes in the fair value of cash flow hedges are also recorded to regulatory assets or liabilities, rather than being deferred in accumulated other comprehensive income.

In PG&E Corporation and the Utility's Condensed Consolidated Balance Sheets, price risk management assets and liabilities associated with the Utility's electricity and gas procurement activities are presented on a net basis by counterparty where the right of offset exists. As PG&E Corporation and the Utility adopted the provisions of FIN 39-1 on January 1, 2008, the net balances include outstanding cash collateral associated with derivative positions. (See Note 2 of the Notes to the Condensed Consolidated Financial Statements for discussion of the adoption of FIN 39-1.) The table below shows the total price risk management derivative balances and the portions that are designated as cash flow hedges:

	Total Price Risk Management Derivatives		Price Risk Management Derivatives Designated as Cash Flow Hedges	
	September 30, 2008 ⁽¹⁾	December 31, 2007 ⁽²⁾	September 30, 2008 ⁽³⁾	December 31, 2007 ⁽⁴⁾
(in millions)				
Current Assets – Prepaid expenses and other	\$ 120	\$ 55	\$ 8	\$ (2) ⁽⁵⁾
Other Noncurrent Assets – Other	177	171	18	42
Current Liabilities – Other	88	67	36	12
Noncurrent Liabilities – Other	117	20	107	3

⁽¹⁾ Balances reflect the allocation of a \$220 million cash collateral receivable balance to Current Assets-Prepaid expenses and other for \$74 million, \$72 million to Other Noncurrent Assets-Other, and \$74 million to Current Liabilities-Other in accordance with FIN 39-1.

⁽²⁾ Balances reflect the allocation of a \$65 million cash collateral receivable balance to Current Assets-Prepaid expenses and other for \$3 million, \$46 million to Other Noncurrent Assets-Other, and \$16 million to Current Liabilities-Other in accordance with FIN 39-1. This collateral was classified as Current Assets-Prepaid expenses and other in the 2007 Annual Report.

⁽³⁾ Balances reflect the allocation of a \$25 million cash collateral receivable balance to Current Assets-Prepaid expenses and other for \$8 million, \$7 million to Other Noncurrent Assets-Other, and \$10 to Current Liabilities-Other in accordance with FIN 39-1.

⁽⁴⁾ Balances reflect the allocation of a \$16 million cash collateral receivable balance to Other Noncurrent Assets-Other for \$9 million and \$7 million to Current Liabilities-Other in accordance with FIN 39-1. This collateral was classified as Current Assets-Prepaid expenses and other in the 2007 Annual Report.

⁽⁵⁾ \$2 million of the cash flow hedges in a liability position at December 31, 2007 relate to counterparties for which the total net derivatives position is a current asset.

As of September 30, 2008, PG&E Corporation and the Utility had cash flow hedges with expiration dates through December 2012 for energy contract derivative instruments.

The Utility also has derivative instruments for the physical delivery of commodities transacted in the normal course of business. These derivative instruments are eligible for the normal purchase and sales exceptions under SFAS No. 133, and are not reflected in the Condensed Consolidated Balance Sheets.

Net realized gains or losses on derivative instruments, including those derivative instruments for which the normal purchase and sales exception has been elected, are recorded in the cost of electricity and the cost of natural gas. Cash inflows and outflows associated with the settlement of price risk management transactions are recognized in operating cash flows on PG&E Corporation and the Utility's Condensed

Consolidated Statements of Cash Flows.

The dividend participation rights of PG&E Corporation's Convertible Subordinated Notes, considered to be derivative instruments, are recorded at fair value in PG&E Corporation's Condensed Consolidated Financial Statements in accordance with SFAS No. 133. (See Note 4 of the Notes to the Condensed Consolidated Financial Statements for discussion of the Convertible Subordinated Notes.)

NOTE 8: FAIR VALUE MEASUREMENTS

On January 1, 2008, PG&E Corporation and the Utility adopted the provisions of SFAS No. 157, which defines fair value measurements and implements a hierarchical disclosure requirement. SFAS No. 157 deferred the disclosure of the hierarchy for certain non-financial instruments to fiscal years beginning after November 15, 2008.

SFAS No. 157 defines fair value as “the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date,” or the “exit price.” Accordingly, an entity must now determine the fair value of an asset or liability based on the assumptions that market participants would use in pricing the asset or liability, not those of the reporting entity itself. The identification of market participant assumptions provides a basis for determining what inputs are to be used for pricing each asset or liability. Additionally, SFAS No. 157 establishes a fair value hierarchy that gives precedence to fair value measurements calculated using observable inputs over those using unobservable inputs. Accordingly, the following levels were established for each input:

Level 1: “Inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date.” Active markets are those in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis. Instruments classified as Level 1 consist of financial instruments such as exchange-traded derivatives (other than options), listed equities, and U.S. government treasury securities.

Level 2: “Inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly.” Instruments classified as Level 2 consist of financial instruments such as non-exchange-traded derivatives (other than options) valued using exchange inputs and exchange traded derivatives (other than options) for which the market is not active.

Level 3: “Unobservable inputs for the asset or liability.” These are inputs for which there is no market data available, or observable inputs that are adjusted using Level 3 assumptions. Instruments classified as Level 3 consist primarily of financial and physical instruments such as options, non-exchange-traded derivatives valued using broker quotes, and new and/or complex instruments that have immature or limited markets.

SFAS No. 157 is applied prospectively with limited exceptions. One such exception relates to SFAS No. 157’s nullification of a portion of Emerging Issues Task Force (“EITF”) No. 02-3, “Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities” (“EITF 02-3”). Prior to the issuance of SFAS No. 157, EITF 02-3 prohibited an entity from recognizing a day one gain or loss on derivative contracts based on the use of unobservable inputs. A day one gain or loss is the difference between the transaction price and the fair value of the contract on the day the derivative contract is executed (i.e., at inception). Prior to the adoption of SFAS No. 157, the Utility did not record any day one gains associated with Congestion Revenue Rights (“CRRs”) as the fair value was based primarily on unobservable market data. (CRRs allow market participants, including load serving entities, to hedge the financial risk of congestion charges imposed by the California Independent System Operator (“CAISO”) in the day-ahead market to be established when the CAISO’s Market Redesign and Technology Upgrade (“MRTU”) becomes effective.) The costs associated with procuring CRRs are currently being recovered in rates or are probable of recovery in future rates. The adoption of SFAS No. 157 permitted the Utility to record day one gains associated with CRRs resulting in a \$48 million increase in price risk management assets and the related regulatory liabilities as of January 1, 2008.

The following table sets forth the fair value hierarchy by level of PG&E Corporation and the Utility’s recurring fair value financial instruments as of September 30, 2008. The instruments are classified based on the lowest level of input that is significant to the fair value measurement. PG&E Corporation 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 September 30, 2008				
(in millions)	Level 1	Level 2	Level 3	Total
Assets:				
Money market investments (held by PG&E Corporation)	\$ 192	\$ -	\$ 62	\$ 254
Nuclear decommissioning trusts ⁽¹⁾	1,609	308	7	1,924
Price risk management instruments ⁽²⁾	54	4	34	92
Rabbi trusts ⁽³⁾	78	-	-	78
Long-term disability trust	49	-	79	128
Assets Total	\$ 1,982	\$ 312	\$ 182	\$ 2,476
Liabilities:				
Dividend participation rights	\$ -	\$ -	\$ 49	\$ 49
Other	-	-	5	5
Liabilities Total	\$ -	\$ -	\$ 54	\$ 54

⁽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 \$41 million to Level 1, \$26 million to Level 2, and \$153 million to Level 3.

⁽³⁾ Excludes life insurance policies.

Utility				
Fair Value Measurements as of September 30, 2008				
(in millions)	Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trusts ⁽¹⁾	\$ 1,609	\$ 308	\$ 7	\$ 1,924
Price risk management instruments ⁽²⁾	54	4	34	92
Long-term disability trust	49	-	79	128
Assets Total	\$ 1,712	\$ 312	\$ 120	\$ 2,144
Liabilities:				
Other	\$ -	\$ -	\$ 5	\$ 5
Liabilities Total	\$ -	\$ -	\$ 5	\$ 5

⁽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 \$41 million to Level 1, \$26 million to Level 2, and \$153 million to Level 3.

PG&E Corporation and the Utility's fair value measurements incorporate various factors required under SFAS No. 157 such as the credit standing of the counterparties involved, nonperformance risk including the risk of nonperformance by PG&E Corporation and the Utility on their liabilities, the applicable exit market, and specific risks inherent in the instrument. Nonperformance and credit risk adjustments on the Utility's price risk management instruments are based on current market inputs when available, such as credit default swap spreads. When such information is not available, internal models may be used. As of September 30, 2008, the nonperformance and credit risk adjustment represents approximately 1% 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.

Money Market Investments

PG&E Corporation invests in AAA-rated money market funds that seek to maintain a stable net asset value. These funds invest in high quality, short-term, diversified money market instruments, such as treasury bills, federal agency securities, certificates of deposit, and commercial paper with a maximum weighted average maturity of 60 days or less. PG&E Corporation's investments in these money market funds are generally valued based on observable inputs such as expected yield and credit quality and are thus classified as Level 1 instruments. Approximately \$192 million held in money market funds are recorded as Cash and cash equivalents in PG&E Corporation's Condensed Consolidated Balance Sheets.

As of September 30, 2008, PG&E Corporation classified approximately \$62 million invested in one money market fund as a Level 3 instrument because the fund manager imposed restrictions on fund participants' redemption requests. PG&E Corporation's investment in this money market fund, previously recorded as Cash and cash equivalents, is recorded as Prepaid expenses and other in PG&E Corporation's Condensed Consolidated Balance Sheets. (In October 2008, PG&E Corporation received an initial redemption amount of approximately \$32 million from the money market fund.)

Trust Assets

The nuclear decommissioning trusts, the rabbi trusts related to the non-qualified deferred compensation plans, and the long-term disability trust hold primarily equities, debt securities, mutual funds, and life insurance policies. These instruments are generally valued based on unadjusted prices in active markets for identical transactions or unadjusted prices in active markets for similar transactions. The rabbi trusts are classified as Current Assets-Prepaid expenses and other and Other Noncurrent Assets-Other in PG&E Corporation's Condensed Consolidated Financial Statements. The long-term disability trust is classified as Current Liabilities-Other in PG&E Corporation and the Utility's Condensed Consolidated Financial Statements.

Price Risk Management Instruments

Price risk management instruments are comprised of physical and financial derivative contracts including futures, forwards, options, and swaps that are both exchange-traded and over-the-counter ("OTC") traded contracts. PG&E Corporation and the Utility use similar models to value similar instruments. SFAS No. 71 allows the Utility to defer the unrealized gains and losses associated with these derivatives, as they are expected to be refunded or recovered in future rates.

All energy options (exchange-traded and OTC) are valued using the Black's Option Pricing Model and classified as Level 3 measurements primarily due to volatility inputs.

CRRs, firm transmission rights ("FTRs"), and demand response ("DR") contracts are new and/or complex instruments that have immature or limited markets. CRRs are discussed above. FTRs allow market participants, including load serving entities to hedge both the physical and financial risk associated with CAISO-imposed congestion charges until the MRTU becomes effective. DRs primarily allow market participants, including load serving entities, to manage their capacity requirements. In addition, DR contracts are used to hedge financial risk associated with increased energy prices resulting from increased demand on the electricity grid. Activity in these markets is minimal and observable inputs may not be available in pricing these instruments. Therefore, the pricing models used to value these instruments often incorporate significant estimates and assumptions that market participants would use in pricing the instrument. Accordingly, they are classified as Level 3 measurements.

Exchange-traded derivative instruments (other than options) are generally valued based on unadjusted prices in active markets using pricing models to determine the net present value of estimated future cash flows. Accordingly, a majority of these instruments are classified as Level 1 measurements. However, certain of these exchange-traded contracts are classified as Level 2 measurements because the contract term extends to a point at which the market is no longer considered active but where prices are still observable. This determination is based on an analysis of the relevant characteristics of the market such as trading hours, trading volumes, frequency of available quotes, and open interest. In addition, a number of OTC contracts have been valued using unadjusted exchange prices in active markets. Such instruments are classified as Level 2 measurements as they are not exchange-traded instruments. The remaining OTC derivative instruments are valued using pricing models based on the net present value of estimated future cash flows based on broker quotations. Such instruments are generally classified within Level 3 of the fair value hierarchy as broker quotes are only indicative of market activity and do not necessarily reflect binding offers to transact.

See Note 7 of the Notes to the Condensed Consolidated Financial Statements for further discussion of the price risk management instruments.

Dividend Participation Rights

The dividend participation rights of the Convertible Subordinated Notes are embedded derivative instruments in accordance with SFAS No. 133 and, therefore, are bifurcated from Convertible Subordinated Notes and recorded at fair value in PG&E Corporation's Condensed Consolidated Balance Sheets. The dividend participation rights are valued based on the net present value of estimated future cash flows using internal estimates of common stock dividends. These rights are recorded as Current Liabilities-Other and Noncurrent Liabilities-Other in PG&E Corporation's Condensed Consolidated Balance Sheets. (See Note 4 of the Notes to the Condensed Consolidated Financial Statements for further discussion of these instruments.)

Level 3 Rollforward

The following table is a reconciliation of changes in fair value of instruments that have been classified as Level 3 in the fair value hierarchy for the nine month period ended September 30, 2008:

PG&E Corporation								
(in millions)	Money Market Investments	Price Risk Management Instruments	Nuclear Decommissioning Trusts ⁽³⁾	Long- term Disability	Dividend Participation Rights	Other	Total	
Asset (liability) Balance as of January 1, 2008		\$ -	\$ 115 ⁽¹⁾	\$ 8	\$ 69	\$ (68) ⁽²⁾	\$ (4)	\$ 120
Realized and unrealized gains (losses):								
Included in earnings		-	-	-	-	(2)	-	(2)
Included in regulatory assets and liabilities or balancing accounts		-	(81)	(1)	(12)	-	(1)	(95)
Purchases, issuances, and settlements		-	-	-	22	21	-	43
Transfers in (out) of Level 3	62	-	-	-	-	-	-	62
Asset (liability) Balance as of September 30, 2008	\$ 62	\$ 34	\$ 7	\$ 79	\$ (49)	\$ (5)	\$ 128	

Earnings for the period were impacted by a \$2 million unrealized loss relating to assets or liabilities still held at September 30, 2008.

⁽¹⁾ Includes the impact of the \$48 million retrospective adjustment related to the CRRs on January 1, 2008. Additionally, the balance includes the impact of netting adjustments of \$6 million made in accordance with the requirements of FIN 39-1.

⁽²⁾ The discount factor used to value these rights was adjusted on January 1, 2008 in order to comply with the provisions of SFAS No. 157, resulting in a \$6 million expense to increase the value of the liability.

⁽³⁾ Excludes taxes on appreciation of investment value.

Utility						
(in millions)	Price Risk Management Instruments	Nuclear Decommissioning Trusts ⁽²⁾	Long-term Disability	Other	Total	
Asset (liability) Balance as of January 1, 2008	\$ 115 ⁽¹⁾		\$ 8	\$ 69	\$ (4)	\$188
Realized and unrealized gains (losses):						
Included in earnings	-	-	-	-	-	-
Included in regulatory assets and liabilities or balancing accounts	(81)	(1)	(12)	(1)	(95)	
Purchases, issuances, and settlements	-	-	22	-	22	
Transfers in (out) of Level 3	-	-	-	-	-	-
Asset (liability) Balance as of September 30, 2008	\$ 34	\$ 7	\$ 79	\$ (5)	\$ 115	

Earnings for the period were not impacted by unrealized gains or (losses) relating to assets or liabilities still held at September 30, 2008.

⁽¹⁾ Includes the impact of the \$48 million retrospective adjustment related to the CRRs on January 1, 2008. Additionally, the balance includes the impact of netting adjustments of \$6 million made in accordance with the requirements of FIN 39-1

⁽²⁾ Excludes taxes on appreciation of investment value.

The following table is a reconciliation of changes in fair value of instruments that have been classified as Level 3 in the fair value hierarchy for the three month period ended September 30, 2008:

PG&E Corporation							
(in millions)	Money Market Investments	Price Risk Management Instruments	Nuclear Decommissioning Trusts ⁽¹⁾	Long- term Disability	Dividend Participation Rights	Other	Total
Asset (liability) Balance as of June 30, 2008	\$ -	\$ 382	\$ 7	\$ 95	\$ (55)	\$ (6)	\$ 423
Realized and unrealized gains (losses):							
Included in earnings	-	-	-	-	(1)	-	(1)
Included in regulatory assets and liabilities or balancing accounts	-	(348)	-	(5)	-	1	(352)
Purchases, issuances, and settlements	-	-	-	(11)	7	-	(4)
Transfers in (out) of Level 3	62	-	-	-	-	-	62
Asset (liability) Balance as of September 30,							

2008	\$ 62	\$ 34	\$ 7	\$ 79	\$ (49)	\$ (5)	\$ 128
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Earnings for the period were impacted by a \$1 million unrealized loss relating to assets or liabilities still held at September 30, 2008.

⁽¹⁾ Excludes taxes on appreciation of investment value.

(in millions)	Utility				
	Price Risk Management Instruments	Nuclear Decommissioning Trusts (1)	Long-term Disability	Other	Total
Asset (liability)					
Balance as of June 30, 2008	\$ 382	\$ 7	\$ 95	\$ (6)	\$ 478
Realized and unrealized gains (losses):					
Included in earnings	-	-	-	-	-
Included in regulatory assets and liabilities or balancing accounts	(348)	-	(5)	1	(352)
Purchases, issuances, and settlements	-	-	(11)	-	(11)
Transfers in (out) of Level 3	-	-	-	-	-
Asset (liability)					
Balance as of September 30, 2008	\$ 34	\$ 7	\$ 79	\$ (5)	\$ 115

Earnings for the period were not impacted by unrealized gains or (losses) relating to assets or liabilities still held at September 30, 2008.

(1) Excludes taxes on appreciation of investment value.

PG&E Corporation and the Utility did not have any nonrecurring financial measurements that are within the scope of SFAS No. 157 as of September 30, 2008.

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

(in millions)	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2008	2007	2008	2007
Utility revenues from:				
Administrative services provided to PG&E Corporation	\$ -	\$ 1	\$ 2	\$ 3
Utility employee benefit assets due from PG&E Corporation	-	-	-	-
Interest from PG&E Corporation on employee benefit assets	-	-	-	1
Utility expenses from:				
Administrative services received from PG&E Corporation	\$ 34	\$ 31	\$ 86	\$ 83
Utility employee benefit assets due to PG&E Corporation	1	1	2	3

At September 30, 2008 and December 31, 2007, the Utility had a receivable of approximately \$27 million and \$29 million, respectively from PG&E Corporation included in Accounts receivable – Related parties and Other Noncurrent Assets – Related parties receivable on the Utility's Condensed Consolidated Balance Sheets and a payable of approximately \$33 million and \$28 million, respectively to PG&E Corporation included in Accounts payable – Related parties on the Utility's Condensed Consolidated Balance Sheets.

NOTE 10: RESOLUTION OF REMAINING CHAPTER 11 DISPUTED CLAIMS

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

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

As of September 30, 2008, the Utility's liability for the remaining net disputed claims was approximately \$1.7 billion, consisting of approximately \$1.6 billion of remaining disputed claims (classified on the Condensed Consolidated Balance Sheets as Accounts payable – Disputed claims and customer refunds) and interest accrued at the FERC-ordered rate of \$0.6 billion (classified on the Condensed Consolidated Balance Sheets as Interest payable) offset by an accounts receivable from the CAISO and the PX of approximately \$0.5 billion (included within Accounts receivable – Customers on the Condensed Consolidated Balance Sheets). These amounts do not include potential remaining refunds that may be due to the Utility as a result of the FERC refund proceedings.

As of September 30, 2008, the Utility held \$1.2 billion in escrow, including approximately \$0.1 billion of earned interest, for payment of the remaining net disputed claims (classified as Restricted cash in the Condensed Consolidated Balance Sheets).

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.

The Utility and the PX have been negotiating the terms of a proposed agreement regarding the potential transfer of \$700 million to the PX from the Utility's escrow account established for disputed claims to enable the PX to fund future settlements, pay refund claims, or amounts owed to CAISO or PX markets, as may be authorized by the FERC or a court of competent jurisdiction. The proposed agreement would be subject to approval by the FERC and by the bankruptcy courts that have jurisdiction of the Chapter 11 proceedings of the PX and the Utility. Under the proposed agreement, the Utility's payment would reduce its liability for remaining net disputed claims. To protect the Utility against the imposition of double liability, the proposed agreement would provide that, to the extent that both the PX and an individual electricity supplier have filed claims relating to the same transaction, such claim would 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 a court of competent jurisdiction. It is uncertain when a final agreement will be executed and, if executed, when required approvals would be obtained.

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, 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, employee matters, 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 electricity at the date of purchase. Forward prices as of September 30, 2008 are used to determine the undiscounted future expected payments for contracts with variable pricing terms. At September 30, 2008, the undiscounted future expected power purchase agreement payments were as follows:

(in millions)	
2008	\$ 565
2009	2,384
2010	2,345
2011	2,309
2012	2,231
Thereafter	18,639
Total	<u>\$ 28,473</u>

Payments made by the Utility under power purchase agreements amounted to approximately \$3,631 million and \$2,367 million for the nine months ended September 30, 2008 and September 30, 2007, respectively. The amounts above do not include payments related to the California Department of Water Resources ("DWR") purchases for the benefit of the Utility's customers, as the Utility only acts as an agent for the DWR.

The following table shows the future fixed capacity payments due under qualifying facility ("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)	
2008	\$ 11
2009	50
2010	50
2011	50
2012	50
Thereafter	254
Total fixed capacity payments	\$ 465
Less: Amount representing interest	(115)
Present value of fixed capacity payments	<u>\$ 350</u>

Minimum lease payments associated with the lease obligation are included in Cost of electricity on PG&E Corporation 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 September 30, 2008, the Utility's undiscounted obligations for natural gas purchases and gas transportation services were as follows:

(in millions)	
2008	\$ 429
2009	804
2010	93
2011	80
2012	49
Thereafter	199
Total	<u>\$ 1,654</u>

Payments for natural gas purchases and gas transportation services amounted to approximately \$2,227 million and \$1,603 million for the nine months ended September 30, 2008 and September 30, 2007, 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. At September 30, 2008, PG&E Corporation's potential exposure under this guarantee was immaterial and PG&E Corporation has not made any provision for this guarantee.

Utility

Application to Recover Hydroelectric Facility Divestiture Costs

On April 14, 2008, the Utility filed an application with the CPUC requesting authorization to recover approximately \$47 million, including \$12.2 million of interest, of the costs it incurred in connection with the Utility's efforts to determine the market value of its hydroelectric generation facilities in 2000 and 2001. These efforts were undertaken at the direction of the CPUC in preparation for the planned divestiture of the facilities to further the development of a competitive generation market in California. In 2003, the CPUC determined that the amount of these costs at the time, \$34.8 million, was reasonable and authorized the Utility to track these costs and seek authorization to recover these costs in the future if the hydroelectric generation facilities were ultimately not divested. The Utility continues to own its hydroelectric generation assets. On May 19, 2008, the CPUC's Division of Ratepayer Advocates ("DRA") filed a protest to the Utility's application. On August 14, 2008, the DRA and the Utility agreed that the Utility had supported its request with appropriate and reasonable evidence. PG&E Corporation and the Utility are unable to predict whether the CPUC will approve recovery of these costs.

California Department of Water Resources Contracts

Electricity purchased under the DWR allocated power purchase contracts with various generators provided approximately 15.2% of the electricity delivered to the Utility's customers for the nine months ended September 30, 2008. The DWR remains legally and financially responsible for its power purchase contracts. The Utility acts as a billing and collection agent of the DWR's revenue requirements from the Utility's customers.

The DWR has stated publicly in the past that it intends to transfer full legal title of, and responsibility for, the DWR power purchase contracts to the California investor-owned electric utilities as soon as possible. However, the DWR power purchase contracts cannot be transferred to the Utility without the consent of the CPUC. In addition, the Chapter 11 Settlement Agreement provides that the CPUC will not require the Utility to accept an assignment of, or to assume legal or financial responsibility for, the DWR power purchase contracts unless each of the following conditions has been met:

- After assumption, the Utility's issuer rating by Moody's Investors Service ("Moody's") will be no less than A2 and the Utility's long-term issuer credit rating by Standard and Poor's Rating Service ("S&P") will be no less than A. The Utility's current issuer rating by Moody's is A3 and the Utility's long-term issuer credit rating by S&P is BBB+;
- The CPUC first makes a finding that the DWR power purchase contracts to be assumed are just and reasonable; and
- The CPUC has acted to ensure that the Utility will receive full and timely recovery in its retail electricity rates of all costs associated with the DWR power purchase contracts to be assumed without further review.

The CPUC has opened a proceeding to investigate how the DWR can end its role in purchasing power for the customers of the California investor-owned utilities. Until the DWR's obligations under its power purchase contracts are terminated, the CPUC is prohibited by state law from reinstating "direct access". Direct access is the ability of retail end-user customers to purchase electricity from energy providers other than the California investor-owned electric utilities. The CPUC has opened a proceeding to investigate how the DWR can end its role in purchasing power for the customers of the California investor-owned utilities, through novation of the DWR contracts or otherwise. A proposed decision was issued on October 7, 2008, that, if adopted by the CPUC, would set January 1, 2010 as the target date for completing negotiations to determine whether the DWR contracts can be novated and transferred to the Utility and other investor-owned utilities ending the DWR's power procurement role. The CPUC is expected to issue a final decision by the end of 2008.

Incentive Ratemaking for Energy Efficiency Programs

The CPUC has 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. The maximum amount of incentives that the Utility may receive and the amount of any reimbursement obligations the Utility may incur over the 2006-2008 program cycle is \$180 million. The financial impact will depend on the amount of any shareholder incentives the Utility may receive or the amount of any reimbursement obligations the Utility may incur based on the level of energy efficiency savings actually achieved over the three-year program cycle and when the applicable accounting standard for recognizing incentives or reimbursement obligations is met.

Nuclear Insurance

The Utility has several types of nuclear insurance for the two nuclear operating units at its Diablo Canyon nuclear generating facilities ("Diablo Canyon") and for its retired nuclear generation facility at Humboldt Bay ("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 megawatts ("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 Nuclear Regulatory Commission for public liability arising from nuclear incidents covering liabilities in excess of the \$53.3 million of liability insurance.

Severance

In connection with the Utility's initiatives to streamline processes and achieve cost and operating efficiencies, the Utility is eliminating and consolidating various employee positions. As a result, the Utility has incurred severance costs and expects that it will incur additional severance costs. The amount of future severance costs will depend on many variables, including whether affected employees elect to receive severance benefits or reassignment, the number of available vacant positions for those seeking reassignment, and for those employees who elect severance benefits, their years of service and annual salaries. At September 30, 2008, the Utility estimated future severance costs will range from \$29 million to \$48 million, given the uncertainty of each of these variables. The Utility has recorded a liability of \$29 million as of September 30, 2008. The following table presents the changes in the liability from December 31, 2007:

(in millions)	
Balance at December 31, 2007	\$ 30
Additional severance accrued	17
Less: Payments	(18)
Balance at September 30, 2008	<u>\$ 29</u>

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 \$575 million at September 30, 2008, and approximately \$528 million at December 31, 2007. The \$575 million accrued at September 30, 2008 consists of:

- Approximately \$222 million for remediation at the Hinkley and Topock natural gas compressor sites;
- Approximately \$83 million related to remediation at divested generation facilities;
- Approximately \$221 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 \$49 million related to remediation costs for fossil decommissioning sites.

Of the approximately \$575 million environmental remediation liability, approximately \$126 million has been included in prior rate setting proceedings. The Utility expects that an additional amount of approximately \$359 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.

The Utility's undiscounted future costs could increase to as much as \$940 million 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 \$940 million 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. In April 2008, the U.S. Supreme Court agreed to review the Second Circuit decision regarding the cost-benefit test and a decision is expected by mid-2009. 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.

California Labor Code Issues

Hourly paid employees in California are entitled to an unpaid, uninterrupted 30-minute duty-free meal period for every four hours of work. Pursuant to California Labor Code Section 226.7, employers who fail to provide the mandated meal period must provide an employee with one additional hour of pay at the employee's regular rate of compensation for each work day that the meal period is not provided. If the employee worked during the 30-minute unpaid meal period, the employer also must pay the employee for this time. In April 2007, the California Supreme Court ruled that the payment required under this law is a "wage" rather than a penalty, and that claims brought for violation of this law are subject to a three-year statute of limitations rather than the one-year statute of limitations applicable to claims for penalty payments.

The collective bargaining agreement between the Utility and the International Brotherhood of Electrical Workers, Local 1245, AFL-CIO ("IBEW"), which covers approximately 10,300 employees, does not provide certain employee groups a continuous 30-minute meal period. In June 2007, the Utility and the IBEW agreed that covered employees whose eight-hour shifts do not allow for an uninterrupted 30-minute meal break would be paid one hour of pay for each 30-minute meal period missed going back 39 months. Further, in July 2007, the Utility and IBEW established a joint committee to review payroll records to determine if payments were due to other IBEW- represented employees who missed a meal due to business needs. That review is continuing. Effective September 2007, the Utility instituted use of a new payroll time sheet to ensure all missed meals are accurately recorded by employees and paid for by the Utility.

In connection with those employees whose eight-hour shifts do not allow for an uninterrupted 30-minute meal period, the Utility has paid \$24 million as of September 30, 2008. Additionally, at September 30, 2008, the Utility accrued \$5.7 million for probable future payments related to missed meals. The Utility is unable to estimate the additional amount of loss it may incur in connection with this matter. The ultimate outcome of this matter may have a material adverse impact on PG&E Corporation and the Utility's financial condition or results of operations.

Tax Matters

In the first quarter of 2008, PG&E Corporation reached a settlement with the Internal Revenue Service ("IRS") appellate division for tax years 1997-2000. On July 9, 2008, PG&E Corporation was notified that the U.S. Congress' Joint Committee on Taxation ("Joint Committee") had approved the settlement. As a result of the settlement, PG&E Corporation received a \$16 million refund from the IRS in October 2008. This settlement did not result in material changes to the amount of unrecognized tax benefits that PG&E Corporation recorded under FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes."

On June 20, 2008, PG&E Corporation reached an agreement with the IRS regarding a change in accounting method related to the capitalization of indirect service costs for tax years 2001-2004. This agreement resulted in a \$29 million benefit from a reduction in interest expense accrued on unrecognized tax benefits partially offset by a \$15 million liability associated with unrecognized state tax benefits, for a net tax benefit of approximately \$14 million. In addition, on June 27, 2008, PG&E Corporation agreed to the revenue agent reports ("RARs") from the IRS that reflected this agreement and resolved all significant 2001-2002 audit issues, except for issues related to synthetic fuel tax credits, and all 2003-2004 audit issues. On August 26, 2008, PG&E Corporation signed a separate closing agreement that favorably resolved the issues related to the synthetic fuel tax credits. The RARs and closing agreement were submitted to the Joint Committee for approval.

On October 28, 2008, the IRS executed the RARs and the closing agreement after the Joint Committee indicated it had taken no exception to the resolution of the 2001-2004 audits. As a result of the resolution of 2001-2004 audits, PG&E Corporation expects to receive a refund of approximately \$310 million and recognize after-tax income in the fourth quarter of 2008 of approximately \$230 million. Approximately \$180 million of the refund will be allocated to the Utility and approximately \$60 million of the after-tax income will be attributable to the Utility. The after-tax income of \$230 million includes approximately \$175 million primarily related to a reduction in PG&E Corporation's liability associated with unrecognized tax benefits and approximately \$55 million associated with the utilization of federal capital loss carry forwards, as discussed below. (All these amounts exclude interest.) There are no other anticipated changes to the unrecognized tax benefits within the next 12 months.

As of September 30, 2008, PG&E Corporation had \$268 million of federal capital loss carry forwards based on tax returns as filed, primarily resulting from the disposition of NEG stock in 2004. The resolution of the 2001-2004 audits will 1) reduce the capital loss carry forwards by approximately \$51 million due to losses allowed in the audit settlements, and 2) utilize approximately \$156 million of the federal capital loss carry forwards resulting in after-tax income of approximately \$55 million, excluding interest, in the fourth quarter of 2008. PG&E Corporation's remaining federal capital loss carry forwards will be approximately \$61 million, of which \$20 million will expire if not used by December 2009.

The IRS is currently auditing tax years 2005-2007. For tax year 2008, PG&E Corporation has been participating in the IRS' Compliance Assurance Process, a real-time audit process intended to expedite the resolution of issues raised during audits.

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 \$2.1 billion of California capital loss carry forwards based on tax returns as filed, the majority of which, if not used by December 2008, will expire.

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 provisions are reviewed quarterly and adjusted to reflect the impacts of negotiations, 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 and the Utility's policy is to exclude anticipated legal costs.

The accrued liability for legal matters is included in PG&E Corporation and the Utility's Current Liabilities - Other in the Condensed Consolidated Balance Sheets, and totaled approximately \$47 million at September 30, 2008 and approximately \$78 million at December 31, 2007.

After considering the above accruals, PG&E Corporation and the Utility do not expect that losses associated with legal matters will have a material impact on their financial condition or results 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 September 30, 2008. The Utility had approximately \$39 billion in assets at September 30, 2008 and generated revenues of approximately \$11 billion in the nine months ended September 30, 2008.

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 and the Utility's combined Annual Report on Form 10-K for the year ended December 31, 2007, which, together with the information incorporated by reference into such report, is referred to in this quarterly report as the "2007 Annual Report." Significant developments that have occurred since the 2007 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 which the Utility is required to consolidate under applicable accounting standards and 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 Notes to the Consolidated Financial Statements incorporated by reference in the 2007 Annual Report.

Summary of Changes in Earnings per Common Share and Net Income for the Three and Nine Months Ended September 30, 2008

For the three months ended September 30, 2008, PG&E Corporation's diluted earnings per common share ("EPS") was \$0.83 compared to \$0.77 for the same period in 2007. For the nine months ended September 30, 2008, PG&E Corporation's diluted EPS was \$2.24 compared to \$2.22 for the same period in 2007. PG&E Corporation's net income for the three months ended September 30, 2008 increased by approximately \$26 million, or 9%, to \$304 million, compared to \$278 million for the same period in 2007. For the nine months ended September 30, 2008, net income increased by approximately \$18 million, or 2%, to \$821 million, compared to \$803 million for the same period in 2007.

The increase in diluted EPS and net income for the three months ended September 30, 2008 compared to the same period in 2007 is primarily due to the Utility's return on equity ("ROE") on higher authorized capital investments (representing a \$22 million increase in net income as compared to the same period in the prior year). The increase in diluted EPS and net income for the nine months ended September 30, 2008 compared to the same period in 2007 is primarily due to the Utility's ROE on higher authorized capital investments (representing a \$73 million increase in net income as compared to the same period in the prior year), partially offset by (1) higher storm and outage-related costs, largely due to severe winter weather that occurred in January 2008 (resulting in a \$27 million decrease in net income as compared to the same period in the prior year), (2) increased operating and maintenance expenses associated with the natural gas system (resulting in a \$17 million decrease in net income as compared to the same period in the prior year), and (3) increased refueling expenses at the Utility's Diablo Canyon nuclear generating facilities ("Diablo Canyon") resulting from an extended outage to replace the steam generators in one of the nuclear generating units (resulting in a \$6 million decrease in net income as compared to the same period in the prior year).

Key Factors Affecting Results of Operations and Financial Condition

PG&E Corporation 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 and the Utility's results of operations and financial condition, including:

- *The Outcome of Regulatory Proceedings and the Impact of Ratemaking Mechanisms* . The amount of the Utility's revenues and the amount of costs that the Utility is authorized to recover from customers are primarily determined through regulatory proceedings. 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 projects, such as new power plants, gas or electric transmission facilities, installation of an advanced metering infrastructure, and reliability improvements. The Utility's revenues can also be affected by incentive ratemaking, such as the CPUC's customer energy efficiency shareholder incentive mechanism. The amount of incentives the Utility may receive and the amount of any reimbursement obligations the Utility may incur will depend on the level of energy efficiency savings actually achieved over the three-year program cycles (2006-2008 and 2009-2011). (See "Regulatory Matters" below.) Finally, the outcome of regulatory proceedings may also be affected by volatility in the prices of natural gas and electricity as these costs are passed through to customers in the form of higher rates.
- *Capital Structure and Return on Common Equity*. On May 29, 2008, the CPUC adopted a new three-year cost of capital mechanism to replace the CPUC's annual cost of capital proceeding. The Utility's current authorized capital structure, including a 52% common equity component, will be maintained through 2010. The Utility's current authorized cost of capital, including a ROE of 11.35% on its electric and natural gas distribution and electric generation rate base, will be maintained through 2010, unless the annual automatic adjustment mechanism established by the CPUC is triggered. The Utility can apply for an adjustment to either the capital structure or cost of capital sooner based on extraordinary circumstances. (See "Regulatory Matters" below.)
- *The Ability of the Utility to Control Costs While Improving Reliability* . The Utility's revenue requirements are primarily set based on forecasted operating expenses and capital expenditures. The Utility's revenue requirements are designed to allow the Utility to earn an ROE, as well as to 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. The Utility anticipates that it will incur higher expenses than originally forecasted in the GRC to maintain the aging infrastructure of its electric and natural gas systems and to improve operating and maintenance processes. The Utility intends to continue its efforts to identify and implement initiatives to achieve operational efficiencies to create future sustainable cost-savings and to offset increased spending related to the natural gas system and the increasing cost of materials. (See "Results of Operations – Operating and Maintenance" below.) When capital is placed in service at a higher rate than forecasted, the Utility incurs associated depreciation, property tax, and interest expense. The Utility does not recover an ROE on the higher level of capital expenditures until added to rate base in future rate cases. The Utility's financial condition and results of operations will be impacted by the amount of revenue requirements it is authorized to recover, the amount and timing of its capital expenditures, and whether the Utility is able to manage its operating costs and capital expenditures within authorized levels.
- *The Availability of Debt and Equity Financing*. The Utility's needs for additional financing during 2008 and future years will be affected by the amount and timing of capital expenditures, as well as by 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 Utility's ability to make scheduled principal and interest payments, refinance debt, fund operations, deposit collateral in connection with its natural gas and electricity procurement hedging contracts, and make planned capital expenditures, depends on the levels of its operating cash flow and access to the capital markets. The recent financial distress experienced at major financial institutions has caused significant disruption in the capital markets. Although the Utility continues to have access to the commercial paper markets, short-term interest rates have increased significantly. Interest rates on long-term debt also have increased. For example, the Utility's \$600 million principal amount of 10-year senior notes issued on October 21, 2008 bear interest at 8.25% compared to the Utility's \$700 million principal amount of 10-year senior notes issued in December 2007 and March 3, 2008 that bears interest at 5.625%. The timing and amount of PG&E Corporation's future equity contributions to the Utility will affect the timing and amount of any PG&E Corporation equity issuances and/or debt issuances which, in turn, will affect PG&E Corporation's results of operations and financial condition. (See "Liquidity and Financial Resources" below.)

In addition to the key factors discussed above, PG&E Corporation and the Utility's future results of operations and financial condition are subject to the risk factors discussed in the section entitled "Risk Factors" in the 2007 Annual Report and the section entitled "PART II Item 1A. Risk Factors" below.

FORWARD-LOOKING STATEMENTS

This combined quarterly report on Form 10-Q, including the 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, anticipated costs and savings associated with the Utility's efforts to identify and implement initiatives to achieve operational efficiencies and to create future sustainable cost-savings, estimated capital expenditures, estimated environmental remediation liabilities, estimated tax liabilities, the anticipated outcome of various regulatory and legal proceedings, 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," "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 operating expenses within authorized levels and recover such costs through rates in a timely manner;
- the outcome of regulatory proceedings, including pending and future ratemaking proceedings at the CPUC and the FERC;
- 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;
- the effect of weather, storms, earthquakes, fires, floods, disease, other natural disasters, explosions, accidents, mechanical breakdowns, 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 Diablo Canyon, 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 it has recognized from operating efficiencies it has achieved and identify and successfully implement additional sustainable cost-saving measures;
- whether the Utility incurs substantial unanticipated 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 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 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 and the Utility's future financial condition and results of operations, see the discussion in the section entitled "Risk Factors" in the 2007 Annual Report and the section entitled "PART II Item 1A. Risk Factors" below. PG&E Corporation and the Utility do not undertake an

obligation to update forward-looking statements, whether in response to new information, future events or otherwise.

RESULTS OF OPERATIONS

The table below details certain items from the accompanying Condensed Consolidated Statements of Income for the three and nine months ended September 30, 2008 and 2007:

(in millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Utility				
Electric operating revenues	\$ 2,880	\$ 2,574	\$ 8,039	\$ 7,107
Natural gas operating revenues	794	705	2,946	2,714
Total operating revenues	3,674	3,279	10,985	9,821
Cost of electricity	1,282	998	3,406	2,606
Cost of natural gas	351	281	1,613	1,431
Operating and maintenance	982	950	3,009	2,788
Depreciation, amortization, and decommissioning	419	465	1,239	1,325
Total operating expenses	3,034	2,694	9,267	8,150
Operating income	640	585	1,718	1,671
Interest income	20	33	77	116
Interest expense	(170)	(189)	(528)	(549)
Other income (expense), net ⁽¹⁾	(5)	9	14	28
Income before income taxes	485	438	1,281	1,266
Income tax provision	167	159	421	458
Income available for common stock	\$ 318	\$ 279	\$ 860	\$ 808
PG&E Corporation, Eliminations and Other ⁽²⁾				
Operating revenues	\$ -	\$ -	\$ -	\$ -
Operating expenses	1	3	2	6
Operating loss	(1)	(3)	(2)	(6)
Interest income	3	3	5	9
Interest expense	(8)	(7)	(22)	(22)
Other expense, net	(12)	(2)	(28)	(6)
Loss before income taxes	(18)	(9)	(47)	(25)
Income tax benefit	(4)	(8)	(8)	(20)
Net loss	\$ (14)	\$ (1)	\$ (39)	\$ (5)
Consolidated Total				
Operating revenues	\$ 3,674	\$ 3,279	\$ 10,985	\$ 9,821
Operating expenses	3,035	2,697	9,269	8,156
Operating income	639	582	1,716	1,665
Interest income	23	36	82	125
Interest expense	(178)	(196)	(550)	(571)
Other income (expense), net ⁽¹⁾	(17)	7	(14)	22
Income before income taxes	467	429	1,234	1,241
Income tax provision	163	151	413	438
Net income	\$ 304	\$ 278	\$ 821	\$ 803

⁽¹⁾ Includes preferred stock dividend requirement as other expense.

⁽²⁾ PG&E Corporation eliminates all intercompany transactions in consolidation.

Utility

The following presents the Utility's operating results for the three and nine months ended September 30, 2008 and 2007.

Electric Operating Revenues

The Utility provides electricity to residential, industrial, 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 September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Electric revenues	\$ 3,255	\$ 3,172	\$ 9,044	\$ 8,765
DWR pass-through revenues ⁽¹⁾	(375)	(598)	(1,005)	(1,658)
Total electric operating revenues	\$ 2,880	\$ 2,574	\$ 8,039	\$ 7,107
Total electricity sales (in millions of kWh) ⁽²⁾	21,183	18,688	56,660	49,643

⁽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.

⁽²⁾ These volumes exclude electricity provided by DWR.

The Utility's electric operating revenues increased by approximately \$306 million, or 12%, in the three months ended September 30, 2008 and approximately \$932 million, or 13%, in the nine months ended September 30, 2008, compared to the same periods in 2007 mainly due to the following factors:

- Electricity procurement costs passed through to customers increased by approximately \$291 million in the three months ended September 30, 2008 and approximately \$798 million in the nine months ended September 30, 2008, primarily due to an increase in the volume of power purchased by the Utility following the DWR's termination of a power purchase contract in December 2007 and during the extended scheduled outage at Diablo Canyon earlier this year, and increases in purchased power prices. (See "Cost of Electricity" below.)
- Electric operating revenues to fund public purpose and energy efficiency programs increased by approximately \$36 million in the three months ended September 30, 2008 and approximately \$175 million in the nine months ended September 30, 2008 primarily due to an increase in expenses for these programs. (See "Operating and Maintenance" below.)
- Base revenue requirements increased by approximately \$26 million in the three months ended September 30, 2008 and approximately \$77 million in the nine months ended September 30, 2008, as a result of attrition adjustments as authorized in the 2007 GRC.
- Electric transmission revenues increased by approximately \$13 million in the three months ended September 30, 2008 and approximately \$40 million in the nine months ended September 30, 2008, primarily due to an increase in rates as authorized in the current TO rate case.
- Other electric operating revenues increased by approximately \$22 million in the three months ended September 30, 2008 and approximately \$70 million in the nine months ended September 30, 2008 primarily due to increases in revenues to recover costs related to the Diablo Canyon steam generator replacement project and revenues to fund the SmartMeterTM advanced metering project (see "Capital Expenditures" below for further discussion of SmartMeterTM).

These increases were partially offset by a decrease of approximately \$76 million in the three months ended September 30, 2008 and approximately \$210 million in the nine months ended September 30, 2008, representing the amount of revenue collected during the comparable periods in 2007 for payment of principal and interest on the rate reduction bonds (“RRBs”) that matured in December 2007 and approximately \$6 million and \$18 million for the three and nine months ended September 30, 2008, representing the amount of revenue collected for payment of the energy recovery bonds (“ERBs”) due to their declining balance.

The Utility’s electric operating revenues for 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. 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 SmartMeterTM advanced metering project. Revenues would also increase to the extent 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. Finally, future electric operating revenues are impacted by changes in the Utility’s electricity procurement costs as discussed under “Cost of Electricity” below.

Cost of Electricity

The Utility’s cost of electricity includes electricity purchase costs, the cost of fuel used by its generation facilities, the cost of fuel supplied to other facilities under tolling agreements, and realized gains and losses on price risk management activities. (See Note 7 and 8 of the Notes to the Condensed Consolidated Financial Statements for further information.) The Utility’s cost of purchased power, cost of fuel used in Utility-owned generation, and cost of fuel supplied to other facilities under tolling agreements are passed through to customers. 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 September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Cost of purchased power	\$ 1,334	\$ 990	\$ 3,511	\$ 2,609
Proceeds from surplus sales allocated to the Utility	(90)	(26)	(225)	(112)
Fuel used in own generation	38	34	120	109
Total cost of electricity	\$ 1,282	\$ 998	\$ 3,406	\$ 2,606
Average cost of purchased power per kWh	\$ 0.091	\$ 0.088	\$ 0.089	\$ 0.087
Total purchased power (in millions of kWh)	14,726	11,291	39,377	29,975

The Utility’s total cost of electricity increased by approximately \$284 million, or 28%, in the three months ended September 30, 2008 and by approximately \$800 million, or 31%, in the nine months ended September 30, 2008, compared to the same periods in 2007. These increases were primarily driven by increases in the total volume of purchased power of 3,435 million kilowatt-hours (“kWh”), or 30%, for the three months ended September 30, 2008 and 9,402 million kWh, or 31%, for the nine months ended September 30, 2008. Following the DWR’s termination of its power purchase agreement with Calpine Corporation in December 2007, the volume of power provided by the DWR to the Utility’s customers decreased. As a result, the Utility was required to increase its purchases of power from third parties to meet customer load. Higher market prices also contributed to an increase in the cost of purchased power for the three and nine months ended September 30, 2008 compared to the same periods in 2007. In addition, during the nine months ended September 30, 2008, the Utility increased the volume of power it purchased from third parties during the extended outage at Diablo Canyon Unit 2 that lasted from February through mid-April 2008. (See “Operating and Maintenance” below.) In comparison, because the refueling outage of Diablo Canyon Unit 1 occurred entirely during May 2007, the increase in the volume of purchased power for the same period in 2007 was lower.

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 are terminated or expire. The Utility expects that its cost of electricity in 2008 will continue to increase compared to 2007 as the Utility continues to purchase replacement power due to the DWR's termination of its power purchase agreement with Calpine Corporation in December 2007. 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 is expected to impact the Utility's cost of electricity for the remainder of 2008 and future years. The Utility's future cost of electricity also may be affected by federal or state legislation or rules which 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. As directed by recent California legislation, the CPUC has already adopted an interim greenhouse gas emissions performance standard that would apply to electricity procured or generated by the Utility.

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 September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Bundled natural gas revenues	\$ 709	\$ 620	\$ 2,699	\$ 2,469
Transportation service-only revenues	85	85	247	245
Total natural gas operating revenues	\$ 794	\$ 705	\$ 2,946	\$ 2,714
Average bundled revenue per Mcf ⁽¹⁾ of natural gas sold	\$ 20.85	\$ 17.22	\$ 13.36	\$ 12.35
Total bundled natural gas sales (in millions of Mcf)	34	36	202	200

⁽¹⁾ One thousand cubic feet

The Utility's natural gas operating revenues increased by approximately \$89 million, or 13%, in the three months ended September 30, 2008 and by approximately \$232 million, or 9%, in the nine months ended September 30, 2008, compared to the same periods in 2007. These increases were primarily due to an increase in bundled natural gas revenues of approximately \$89 million, or 14%, in the three months ended September 30, 2008 and approximately \$230 million, or 9%, in the nine months ended September 30, 2008. The increases in bundled natural gas revenues for both periods reflect an overall increase in the cost of natural gas over these periods of approximately \$70 million and \$182 million for the three and nine months ended September 30, 2008 (see "Cost of Natural Gas" below), an increase in base revenue requirements as a result of attrition adjustments authorized in the 2007 GRC of approximately \$6 million and \$17 million for the three and nine months ended September 30, 2008, and an increase in natural gas revenues to fund the SmartMeterTM advanced metering project of approximately \$9 million and \$17 million for the three and nine months ended September 30, 2008.

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 a 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 are expected to increase through 2010 due to authorized GRC attrition adjustments and an increase in authorized revenue requirements relating to the SmartMeterTM advanced metering project.

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 Note 7 and 8 of the Notes to the Condensed Consolidated Financial Statements for further information.)

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

(in millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Cost of natural gas sold	\$ 314	\$ 239	\$ 1,517	\$ 1,299
Cost of natural gas transportation	37	42	96	132
Total cost of natural gas	\$ 351	\$ 281	\$ 1,613	\$ 1,431
Average cost per Mcf of natural gas sold	\$ 9.24	\$ 6.64	\$ 7.51	\$ 6.50
Total natural gas sold (in millions of Mcf)	34	36	202	200

The Utility's total cost of natural gas increased in the three and nine months ended September 30, 2008 by approximately \$70 million, or 25%, and by approximately \$182 million, or 13%, compared to the same periods in 2007, primarily due to increases in the average market price of natural gas purchased in the three and nine months ended September 30, 2008. For the nine months ended September 30, 2008, the increase was partially offset by an approximately \$23 million refund the Utility received as part of a settlement with TransCanada's Gas Transmission Northwest Corporation for 2007 gas transmission capacity rates.

The Utility's future cost of natural gas, which will be passed through to customers, will be impacted by both North American and global market forces. Market forces include temperature variability, supply availability, customer demand, economic and financial conditions, liquefied natural gas availability, natural gas storage, and industry perceptions of risks that may affect either availability or demand, such as the possibility of hurricanes in the gas-producing regions of the Gulf of Mexico, or protracted heat waves that may increase gas-fired electric demand from high air conditioning loads.

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 \$32 million, or 3%, and approximately \$221 million, or 8%, in the three and nine months ended September 30, 2008, respectively, compared to the same periods in 2007. Expenses increased mainly due to the following factors:

- Public purpose program and customer energy efficiency incentive program expenses increased by approximately \$48 million and \$187 million in the three and nine months ended September 30, 2008 primarily due to increased customer participation and increased marketing of new and existing programs, including the California Solar Initiative program and the Self-Generation Incentive Program. Of these changes, approximately \$36 million and \$175 million, respectively, were recovered in electric operating revenues and less than \$1 million and \$14 million, respectively, were recovered in natural gas operating revenues. Expenses related to public purpose programs and energy efficiency programs are generally fully recoverable and differences between costs and revenues in a particular period are due to timing differences.
- Costs increased by approximately \$38 million during the nine months ended September 30, 2008 for the repair and restoration of electric distribution systems and to respond to customer inquiries following the January 2008 winter storm. Of the approximately \$38 million in costs, the Utility has requested that the CPUC permit the Utility to recover approximately \$8 million from its customers. There was no similar storm in the same period in 2007.
- Labor costs increased by approximately \$12 million and \$29 million in the three and nine months ended September 30, 2008, respectively, to conduct expanded natural gas leak surveys in parts of the Utility's service territory and to make related repairs in an effort to improve operating and maintenance processes in the Utility's natural gas system.
- There was an increase in maintenance costs of approximately \$10 million in the nine months ended September 30, 2008 compared to the same period in 2007 due to the longer duration of the planned outage of Diablo Canyon Unit 2 in 2008 compared to the Diablo Canyon Unit 1 outage in 2007.
- Costs related to injuries and damages not specifically related to gas or electric lines of business decreased by approximately \$7 million and \$12 million in the three and nine months ended September 30, 2008, respectively, due to increases in reserves during 2007 for which there were no similar increases in 2008.
- Costs decreased by approximately \$12 million in the three months ended September 30, 2008 compared to the same period in 2007 due primarily to an initiative to implement operational efficiencies which occurred primarily during the third quarter of 2007. Costs increased by approximately \$5 million in the nine months ended September 30, 2008 compared to the same period in 2007 due to primarily to an increase in costs related to software maintenance contracts.
- Advertising decreased by approximately \$9 million and \$10 million in the three and nine months ended September 30, 2008 as compared to the same period in 2007.
- Costs decreased by approximately \$12 million for the three and nine months ended September 30, 2008 due to a CPUC decision ordering the Utility make a refund to ratepayers in 2007 related to billing practices for which there was no similar decision in 2008.
- Costs decreased by approximately \$12 million for the nine months ended September 30, 2008 due to a larger increase in accrual in 2007 than in 2008 related to compensation for employees' missed meals. (See Note 11 of the Notes to the Condensed Consolidated Financial Statements for a discussion of California labor code issues.)
- Costs decreased by approximately \$9 million for the nine months ended September 30, 2008 due a larger increase in accrual in 2007 than in 2008 related to employee severance due to the elimination and consolidation of various employee positions.

In addition, there was an aggregate increase of approximately \$12 million and \$7 million in the three and nine months ended September 30, 2008, respectively, representing other miscellaneous operating and maintenance expenses that changed from the comparable periods in 2007.

Operating and maintenance expenses are influenced by wage inflation, benefits, property taxes, the timing and length of Diablo Canyon refueling outages, environmental remediation costs, legal costs, material costs, and various other administrative and general expenses. The Utility anticipates that it will incur higher material, permitting, and labor costs in the future as well as higher costs to operate and maintain its aging infrastructure. The Utility may make additional payments to employees for missed or delayed meals to comply with California labor law as the Utility's investigation into this matter continues. (See Note 11 of the Notes to the Condensed Consolidated Financial Statements for a discussion of California labor code issues.) The Utility is currently negotiating the terms of a collective bargaining agreement with three labor unions covering approximately 13,000 employees. Two of the collective bargaining agreements will expire on December 31, 2008. The other collective bargaining agreement expires on February 28, 2009. The Utility's future labor and benefit costs will be impacted by the terms of the new collective bargaining agreements.

In addition, the Utility anticipates that it will incur costs, not included in forecasts used to set rates in the GRC, to improve operating and maintenance processes used in its natural gas system following the discovery that some operating and maintenance activities were not effective. (See "Risk Factors" in the 2007 Annual Report.) The Utility also expects that it will incur higher expenses in future periods to comply with the requirements of renewed FERC licenses for the Utility's hydroelectric generation facilities. The Utility intends to continue its efforts to identify and implement initiatives to achieve operational efficiencies to create future sustainable cost-savings and to offset increased spending to address operational issues and increasing cost of materials.

Depreciation, Amortization, and Decommissioning

The Utility's depreciation, amortization, and decommissioning expenses decreased by approximately \$46 million, or 10% in the three months ended September 30, 2008 and approximately \$86 million, or 6%, in the nine months ended September 30, 2008, as compared to the same periods in 2007, mainly due to decreases in amortization expense of approximately \$73 million and \$197 million, respectively, related to the RRB regulatory asset. The RRB regulatory asset was fully recovered through rates when the RRBs matured in December 2007 and, as a result, no amortization has been recorded in 2008. These decreases were partially offset by increases to depreciation expense of approximately \$27 million in the three months ended September 30, 2008 and approximately \$111 million in the nine months ended September 30, 2008 primarily due to plant additions and depreciation rate changes as authorized in the 2007 GRC and the current TO rate case.

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 September 30, 2008, the Utility's interest income decreased by approximately \$13 million, or 39%, as compared to the same period in 2007. Interest income decreased by \$10 million primarily due to lower interest rates earned on funds held in escrow related to disputed claims and a lower escrow balance reflecting settlements of disputed claims. There was an additional decrease of approximately \$3 million in other interest income.

In the nine months ended September 30, 2008, the Utility's interest income decreased by approximately \$39 million, or 34%, as compared to the same period in 2007 when the Utility received approximately \$16 million in interest income on a federal tax refund. In addition, there was a decrease of \$26 million in interest income, primarily due to lower interest rates earned on funds held in escrow related to disputed claims and a lower escrow balance reflecting settlements of disputed claims. These decreases were partially offset by an increase of approximately \$3 million in other interest.

The Utility's interest income in 2008 and future periods will be primarily affected by changes in the balance held in escrow related to disputed claims and changes in interest rate levels.

Interest Expense

In the three and nine months ended September 30, 2008, there was a decrease of approximately \$19 million, or 10%, and \$21 million, or 4%, respectively, as compared to the same periods in 2007. Interest expense decreased primarily due to the following factors:

- Interest expense decreased by approximately \$18 million in the three months ended September 30, 2008, and approximately \$16 million in the nine months ended September 30, 2008, primarily due to lower FERC interest rates accrued on the liability for disputed claims.
- Interest expense decreased by approximately \$7 million in the three months ended September 30, 2008, and approximately \$21 million in the nine months ended September 30, 2008, due to the reduction in the outstanding balance of ERBs and the maturity of the RRBs in December 2007.
- Interest expense on pollution control bonds decreased by approximately \$6 million in the three months ended September 30, 2008 and \$13 million in the nine months ended September 30, 2008, due to the repurchase of auction rate pollution control bonds in March and April 2008 and a decrease in interest rates on outstanding variable rate pollution control bonds.
- Interest expense decreased by approximately \$16 million in the nine months ended September 30, 2008, primarily due to lower interest rates affecting various balancing accounts.
- Other interest expense decreased by approximately \$4 million in the three months ended September 30, 2008, primarily due to a lower balance of borrowings outstanding under the Utility's \$2 billion revolving credit facility and approximately \$5 million in the nine months ended September 30, 2008, primarily due to lower commercial paper interest rates.

These decreases were partially offset by additional interest expense of approximately \$16 million in the three months ended September 30, 2008, and approximately \$50 million in the nine months ended September 30, 2008, related to \$1.2 billion in senior notes issued in March and December 2007 and \$600 million in senior notes issued in March 2008.

The Utility's interest expense in 2008 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 for further discussion).

Other Income (Expense), Net

The Utility's other income (expense), net decreased by approximately \$14 million, or 156%, in the three months ended September 30, 2008 and \$14 million, or 50%, in the nine months ended September 30, 2008 compared to the same periods in 2007. These decreases are primarily due to an increase in costs of approximately \$19 million in the three and nine months ended September 30, 2008 due to the Utility's

efforts to oppose the statewide initiative related to renewable energy (Proposition 7) and the City of San Francisco's municipalization efforts.

Income Tax Expense

The Utility's income tax expense increased by approximately \$8 million, or 5%, for the three months ended September 30, 2008 and decreased by approximately \$37 million, or 8%, for the nine months ended September 30, 2008, as compared to the same periods in 2007. The effective tax rates for the three months ended September 30, 2008 and 2007 were 34.1% and 36.0%, respectively. The effective tax rates for the nine months ended September 30, 2008 and 2007 were 32.6% and 35.9%, respectively. The decreases in the effective tax rate for the three and nine months ended September 30, 2008 were primarily due to the IRS' approval of the Utility's change in accounting method for the capitalization of indirect service costs for tax years 2001-2004, which resulted in a reduction of accrued interest on uncertain tax positions. (See Note 11 of the Notes to the Condensed Consolidated Financial Statements for a discussion of "Tax Matters".)

PG&E Corporation, Eliminations, and Other

Operating Revenues and Expenses

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

There were no material changes to PG&E Corporation's operating income in the three and nine months ended September 30, 2008 as compared to the same period in 2007.

Other Expense, Net

PG&E Corporation's other expense increased by approximately \$10 million, or 500%, for the three months ended September 30, 2008, and approximately \$22 million, or 367%, for the nine months ended September 30, 2008 primarily due to an increase in investment losses in the rabbi trusts related to the non-qualified deferred compensation plans.

LIQUIDITY AND FINANCIAL RESOURCES

Overview

PG&E Corporation and the Utility utilize \$200 million and \$2 billion revolving credit facilities, respectively, along with cash generated from operations, to fund electricity and natural gas purchases on behalf of customers, collateral requirements for commodity contracts and, for short periods of time, capital expenditures, among other things. The level of the Utility's short-term debt fluctuates as a result of seasonal demand for electricity and natural gas, energy commodity costs, collateral requirements, the timing and effect of regulatory decisions and financings, and the amount and timing of capital expenditures, among other factors. The Utility generally utilizes long-term senior unsecured debt and equity issuances, while maintaining its CPUC-authorized capital structure, to fund debt maturities and capital expenditures. PG&E Corporation funds equity contributions to the Utility through the issuance of common stock and long-term debt.

Access to the capital markets is essential to the continuation of the Utility's capital expenditure program. The Utility currently plans to incur additional long-term debt of \$3.5 billion to \$4.0 billion through the remainder of 2008 and through 2011, excluding the October pollution control bond financing and senior notes issuance discussed below. Of this amount, the Utility expects to incur approximately \$1.0 billion of long-term debt within the next six months primarily to finance capital expenditures and to refinance \$600 million of long-term debt that will mature in March 2009. In addition, PG&E Corporation expects to issue additional common stock, debt, or other securities to fund a portion of the Utility's future equity needs through 2011.

The recent disruption in the capital markets has made it challenging for companies to access the markets for commercial paper, new credit facilities and unsecured long-term debt. Notwithstanding this volatility, the Utility has continued to have access to the commercial paper market, albeit at higher prices and with shorter duration, and was able to secure a new credit facility to support the pollution control bond financing discussed below. In addition, as discussed below, the Utility was able to issue \$600 million of senior unsecured 10-year notes in October 2008.

These financings have enabled the Utility to repay its outstanding commercial paper such that the Utility has available liquidity of \$1.4 billion as of October 31, 2008, which consists of \$1.1 billion of availability under its revolving credit facility and \$231 million of unrestricted cash and cash equivalents. PG&E Corporation and the Utility believe that the Utility's cash flow from operations, existing sources of liquidity, and access to the capital markets on reasonable terms, will provide adequate resources to fund operating activities, meet anticipated obligations, and finance future capital expenditures.

The amount and timing of the Utility's future financing needs will depend on various factors, including: (1) the conditions in the capital markets and the Utility's ability to access the capital markets; (2) the timing and amount of forecasted capital expenditures, and incremental capital expenditures beyond those currently forecasted, and the ability of the Utility, if necessary, to defer, postpone, or cease certain capital expenditures; (3) the amount of cash internally generated through normal business operations; (4) the amount of collateral required for commodity contract commitments; and (5) the timing of the resolution of the 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). The amount and timing of PG&E Corporation's future financing needs will depend on various factors, including the need to infuse capital in the Utility to

maintain its 52% equity structure and fund capital expenditures.

At September 30, 2008, PG&E Corporation and its subsidiaries had consolidated cash and cash equivalents of approximately \$251 million and restricted cash of approximately \$1.3 billion. At September 30, 2008, PG&E Corporation on a stand-alone basis had cash and cash equivalents of approximately \$194 million; the Utility had cash and cash equivalents of approximately \$57 million and restricted cash of approximately \$1.3 billion. Restricted cash primarily consists of approximately \$1.2 billion of cash held in escrow pending the resolution of the remaining disputed claims filed in the Utility's reorganization proceeding under Chapter 11. PG&E Corporation and the Utility maintain separate bank accounts. PG&E Corporation and the Utility primarily invest their cash in money market funds.

Each of PG&E Corporation's and the Utility's revolving credit facilities include commitments from a well-diversified syndicate of lenders. Neither credit facility permits the lenders to refuse funding a draw solely due to the occurrence of a "material adverse effect" as defined in the facilities. No single lender's commitment represents more than 11% of total borrowing capacity under either facility. As of October 31, 2008, the commitment from Lehman Brothers Bank, FSB represented approximately \$13 million or 7%, of the total borrowing capacity under PG&E Corporation's \$200 million senior credit facility and approximately \$60 million, or 3%, of the Utility's \$2.0 billion working capital facility.

As of September 30, 2008, the Utility had \$273 million of letters of credit and \$533 million of borrowings outstanding under its \$2.0 billion working capital facility. The Utility also treats the amount of its outstanding commercial paper as a reduction to the amount available under its working capital facility. As of September 30, 2008, the Utility had \$802 million of outstanding commercial paper. As of October 31, 2008, the Utility has repaid all of its outstanding commercial paper using the proceeds from the financings discussed below. PG&E Corporation has no outstanding borrowings or letters of credit under its senior credit facility.

On October 21, 2008, the Utility issued \$600 million principal amount of 8.25% 10-year Senior Notes due on October 15, 2018. (See Note 4 of the Notes to the Condensed Consolidated Financial Statements for a discussion of the Utility's other series of Senior Notes issued in 2008.)

In addition to the senior notes issuance, the Utility received \$95 million and \$309 million from the September 22, 2008 and October 29, 2008 sales of pollution control bonds issued by the California Infrastructure and Economic Development Bank ("CIEDB") to partially reimburse the Utility for its March and April 2008 purchase of \$454 million of auction rate pollution control bonds issued in 2005 ("PC2005 bonds"). The September bonds bear interest at 3.75% through September 19, 2010 and are subject to mandatory tender on September 20, 2010 at a price of 100% of the principal amount plus accrued interest. Each series of October bonds is supported by a direct-pay letter of credit that expires on October 29, 2011, unless extended. The October bonds bear interest at variable interest rates not to exceed 12% per year. The initial interest rate on the October bonds was 1.75%. (See Note 4 of the Notes to the Condensed Consolidated Financial Statements for a further discussion of these bonds.) The Utility anticipates that the refinancing of the remaining \$50 million of PC2005 bonds will occur by the end of 2008, subject to conditions in the tax-exempt bond market and the liquidity needs of the Utility.

During the nine months ended September 30, 2008, PG&E Corporation issued 4,023,421 shares of common stock upon exercise of employee stock options, for the account of 401(k) participants, and under its Dividend Reinvestment and Stock Purchase Plan, generating approximately \$150 million of cash. In February 2008 and July 2008, PG&E Corporation contributed \$50 million and \$40 million, respectively, 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. PG&E Corporation expects to issue additional common stock, debt, or other securities, depending on market conditions, to fund a portion of the Utility's future equity needs.

Dividends

During the nine months ended September 30, 2008, the Utility paid common stock dividends totaling \$447 million, including \$426 million of common stock dividends paid to PG&E Corporation and \$21 million of common stock dividends paid to PG&E Holdings, LLC. At December 31, 2007, PG&E Holdings, LLC, a wholly owned subsidiary of the Utility, held approximately 7% of the Utility common stock. Effective August 29, 2008, PG&E Holdings LLC, was dissolved, and the shares subsequently cancelled.

During the nine months ended September 30, 2008, PG&E Corporation paid common stock dividends totaling \$433 million, including \$28 million to Elm Power Corporation. At December 31, 2007, Elm Power Corporation, a wholly owned subsidiary of PG&E Corporation, held 24,665,500 shares of PG&E Corporation common stock. Effective August 29, 2008, Elm Power Corporation was dissolved, and the shares subsequently cancelled.

On September 17, 2008, the Board of Directors of PG&E Corporation declared a dividend of \$0.39 per share, totaling \$140 million, which was paid on October 15, 2008 to shareholders of record on September 30, 2008.

During the nine months ended September 30, 2008, the Utility paid cash dividends to holders of its outstanding series of preferred stock totaling \$10 million. On September 17, 2008, the Board of Directors of the Utility declared a cash dividend on its outstanding series of preferred stock payable on November 15, 2008, to preferred shareholders of record on October 31, 2008.

Utility

Operating Activities

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

The Utility's cash flows from operating activities for the nine months ended September 30, 2008 and 2007 were as follows:

(in millions)	Nine Months Ended September 30,	
	2008	2007
Net income	\$ 870	\$ 818
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, decommissioning, and allowance for equity funds used during construction	1,337	1,417
Deferred income taxes and tax credits, net	470	(35)
Other changes in noncurrent assets and liabilities	55	270
Gain on sale of assets	(1)	(1)
Effect of changes in operating assets and liabilities:		
Accounts receivable	(179)	(82)
Inventories	(153)	(92)
Accounts payable	(85)	(315)
Income taxes receivable/payable	208	228
Regulatory balancing accounts, net	(94)	(238)
Other current assets	(125)	120
Other current liabilities	(80)	35
Other	(3)	(32)
Net cash provided by operating activities	\$ 2,220	\$ 2,093

In the nine months ended September 30, 2008, net cash provided by operating activities increased by approximately \$127 million from the same period in 2007.

In the nine months ended September 30, 2008, net cash provided by operating activities was approximately \$2,220 million. For the nine months ended September 30, 2008, net cash provided by operating activities was primarily impacted by net income of \$870 million, adjusted for noncash depreciation, amortization, decommissioning and allowance for equity funds used during construction of \$1,337 million (see "Results of Operations" above). Additionally, the following changes in operating assets and liabilities positively impacted cash flows during the period:

- Liabilities for deferred income taxes and tax credits increased by approximately \$470 million between December 31, 2007 and September 30, 2008, primarily due to an increase in balancing account revenues and an increase in deductible fixed asset-related book/tax differences based on the 2007 tax return filed in 2008, as well as an increase in balancing account revenues and an increase in deductible tax depreciation as authorized by the 2008 Economic Stimulus Act.
- Income taxes receivable/payable increased by approximately \$208 million between December 31, 2007 and September 30, 2008, primarily due to the accrual of income taxes payable for the first nine months of 2008.

The following changes in operating assets and liabilities negatively impacted cash flows during the period:

- Net collateral paid primarily related to price risk management activities increased by approximately \$155 million between December 31, 2007 and September 30, 2008 as a result of changes in the Utility's exposure to counterparties' credit risk. Collateral payables and receivables are included in the Other changes in noncurrent assets and liabilities, Other current assets, and Other current liabilities in the table above.
- Regulatory balancing accounts, net under-collection increased by approximately \$94 million between December 31, 2007 and September 30, 2008, primarily due to an increase of approximately \$454 million in under-collected electricity procurement costs. This increase was partially offset by an increase of \$172 million in over-collected amounts due to the DWR. (See "Cost of Electricity" above.) The increase in the Regulatory balancing accounts, net under-collection also was partially offset by a refund of approximately \$230 million the Utility received from the California Energy Commission ("CEC"). The funds from the CEC will be refunded to customers in 2009.
- There were miscellaneous other changes in operating assets and liabilities due to timing differences and seasonality.

In the nine months ended September 30, 2007, net cash provided by operating activities was approximately \$2,093 million. For the nine months ended September 30, 2007, net cash provided by operating activities was primarily impacted by net income of \$818 million, adjusted for noncash depreciation, amortization, decommissioning and allowance for equity funds used during construction of \$1,417 million (see "Results of Operations" above). Additionally, increases of approximately \$228 million in income tax payable positively impacted cash flows during the nine month period ending September 30, 2007. The following changes in operating assets and liabilities negatively impacted cash flows during the period:

- Accounts payable decreased by approximately \$315 million primarily due to differences in the timing of purchases and payments of operating expenses.
- Regulatory balancing accounts, net over-collection decreased by approximately \$238 million between December 31, 2006 and September 30, 2007 primarily due to CPUC-authorized rate reductions designed to reduce the over-collection.

As a result of the resolution of 2001-2004 audits, PG&E Corporation expects to receive a refund of approximately \$310 million, excluding interest, in the next several months. Approximately \$180 million of the refund will be allocated to the Utility. (See Note 11 of the Notes to the Condensed Consolidated Financial Statements for a discussion of "Tax Matters".) Additionally, 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. The CPUC has established a balancing account mechanism to adjust the Utility's electric rates whenever the forecasted aggregate over-collections or under-collections of the Utility's electric procurement costs for the current year exceed 5% of the Utility's prior year generation revenues, excluding generation revenues for DWR contracts. In accordance with this mechanism, on August 21, 2008, the CPUC approved the Utility's request to collect from customers the forecasted 2008 end-of-year under-collection of procurement costs, due mainly to rising natural gas costs and lower than forecasted hydroelectric generation. Effective October 1, 2008, customer rates were adjusted to allow the Utility to collect \$645 million in procurement costs through December 2009. The Utility will be updating its forecasted electricity procurement costs in November, for inclusion in the Annual Electric True-Up, which will adjust rates on January 1, 2009.

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 nine months ended September 30, 2008 and 2007 were as follows:

(in millions)	Nine Months Ended September 30,	
	2008	2007
Capital expenditures	\$ (2,691)	\$ (2,035)
Proceeds from sale of assets	21	15
Increase in restricted cash	(3)	(32)
Proceeds from nuclear decommissioning trust sales	1,121	703
Purchases of nuclear decommissioning trust investments	(1,161)	(805)
Net cash used in investing activities	\$ (2,713)	\$ (2,154)

Net cash used in investing activities increased by approximately \$559 million in the nine months ended September 30, 2008 compared to the same period in 2007, primarily due to an increase of approximately \$656 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.)

Financing Activities

The Utility's cash flows from financing activities for the nine months ended September 30, 2008 and 2007 were as follows:

(in millions)	Nine Months Ended September 30,	
	2008	2007
Borrowings under accounts receivable facility and working capital facility	\$ 533	\$ 600
Repayments under accounts receivable facility and working capital facility	(250)	(300)
Net issuance of commercial paper, net of discount of \$9 million in 2008 and \$2 million in 2007	524	91
Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of \$2 million in 2008 and \$10 million in 2007	693	690
Long-term debt repurchased	(454)	-
Rate reduction bonds matured	-	(217)
Energy recovery bonds matured	(260)	(251)
Equity contribution	90	200
Common stock dividends paid	(426)	(381)
Preferred stock dividends paid	(10)	(10)
Other	(31)	29
Net cash provided by financing activities	\$ 409	\$ 451

In the nine months ended September 30, 2008, net cash provided by financing activities decreased by approximately \$42 million compared to the same period in 2007. Cash provided by or used in financing activities is driven by the Utility's financing needs, which depends on the level of cash provided by or used in operating activities and the level of cash provided by or used in investing activities.

PG&E Corporation

Operating Activities

PG&E Corporation's consolidated cash flows from operating activities consist mainly of billings to the Utility for services rendered and payments for employee compensation, and goods and services provided by others to PG&E Corporation. PG&E Corporation also incurs interest costs associated with its debt.

PG&E Corporation, on a stand-alone basis, did not have any material cash flow associated with operating activities for the nine months ended September 30, 2008 and 2007.

Investing Activities

Other than payment of dividends, PG&E Corporation, on a stand-alone basis, did not have any material cash flow associated with investing activities for the nine months ended September 30, 2008 and 2007.

Financing Activities

PG&E Corporation's primary sources of financing funds, on a stand-alone basis, are dividends from the Utility, equity issuances, and external financing. PG&E Corporation's uses of cash, on a stand-alone basis, primarily relate to the payment of common stock dividends and common stock repurchases.

PG&E Corporation, on a stand-alone basis, did not have any material cash flow associated with financing activities for the nine months ended September 30, 2008 and 2007.

CONTRACTUAL COMMITMENTS

PG&E Corporation and the Utility enter into contractual obligations and 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 2007 Annual Report and those arising from normal business activities, PG&E Corporation and the Utility's commitments at September 30, 2008 include \$200 million of 5.625% Senior Notes due November 30, 2017, \$400 million of 6.35% Senior Notes due February 15, 2038, and \$95 million of pollution control bonds series F and G due on November 1, 2026 and December 1, 2018, respectively.

On October 21, 2008, the Utility issued \$600 million of 8.25% Senior Notes due October 15, 2018. In addition, on October 29, 2008, the California Pollution Control Financing Authority and the CIEDB issued \$309 million of pollution control bonds series A through D for the benefit of the Utility. These series of bonds have maturities ranging from 2016 through 2026. (See Notes 4, 5, 10, and 11 of the Notes to the Condensed Consolidated Financial Statements and the 2007 Annual Report for further discussion.)

CAPITAL EXPENDITURES

The Utility expects that capital expenditures will total approximately \$3.6 billion in 2008. During the nine month period ended September 30, 2008, the Utility incurred capital expenditures of approximately \$2.7 billion. (See "Liquidity and Financial Resources – Investing Activities" above.) Depending on conditions in the capital market, the Utility forecasts that it will make various capital investments in its electric and gas transmission and distribution infrastructure to maintain and enhance system reliability and customer service, to extend the life of or replace existing infrastructure, to add new infrastructure to meet already authorized growth, and to implement various initiatives designed to achieve operating and cost efficiencies. 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 SmartMeterTM advanced metering infrastructure.

Proposed Electric Distribution Reliability Program (Cornerstone Improvement Program)

On May 15, 2008, the Utility requested that the CPUC approve the Utility's proposed six-year electric distribution reliability improvement program and authorize the Utility to collect revenues to recover forecasted capital expenditures totaling approximately \$2.3 billion and operating and maintenance expenses totaling approximately \$43 million over the six-year period beginning on January 1, 2009. The amounts requested are incremental to the revenue requirement already authorized by the CPUC in the Utility's 2007 GRC. The program includes initiatives that are designed to decrease the frequency and duration of electricity outages in order to bring the Utility's reliability performance closer to that of other investor-owned electric utilities. The Utility expects that the work performed in the six-year program also would provide additional reliability benefits. The Utility proposes to record program costs and related revenue requirements in a separate balancing account so that the revenue requirement increase would be used only to recover costs associated with the proposed initiatives, and to allow the return of unused amounts to customers. The Utility would seek CPUC review and approval to recover any costs that exceed the CPUC's authorized amount. For the next GRC in 2011, the Utility would provide forecasts that exclude costs related to the proposed reliability improvements. The Utility would continue to record the program costs and related revenue requirements in the balancing account until the GRC following the completion of this program in 2014.

The CPUC's Division of Ratepayer Advocates ("DRA") and The Utility Reform Network ("TURN") have objected to the Utility's request. Among other arguments, the DRA and TURN argue that the Utility's request should be made in a GRC, that it violates the 2007 GRC settlement, and that the revenue requirement authorized in the 2007 GRC fully funds the reasonable amounts the Utility might need to spend on its electric distribution system. They assert that the Utility's request raises many issues including: the adequacy of the funding levels approved in the 2007 GRC, the reasonableness of the Utility's reliability efforts in recent years, the availability of other more appropriate sources of funding between rate cases, including savings in other areas of utility operations, the value of increased reliability to the Utility's customers, and the need for and efficacy of the Utility's proposed ratemaking. The Utility filed its response on June 30, 2008, reiterating its position that the proposed program does not violate the 2007 GRC settlement, that the Utility is permitted to seek additional revenue outside of a GRC, and that the factual issues the DRA and TURN cite justify the need for hearings on the Utility's request.

PG&E Corporation and the Utility cannot predict whether the CPUC will approve the Utility's request.

SmartMeter™ Advanced Metering Project Upgrade

The CPUC has previously authorized the Utility to recover approximately \$1.4 billion in capital costs in connection with its SmartMeter™ advanced metering project. Of this amount, the Utility has incurred capital expenditures of \$504 million through September 30, 2008. The Utility's request to recover additional expenditures of \$572 million, including \$463 million of additional capital expenditures to upgrade certain elements of the Utility's SmartMeter™ program is still pending at the CPUC. On June 30, 2008, the DRA and TURN recommended that the CPUC reject the Utility's request. In the alternative, the DRA and TURN recommend that the CPUC authorize reduced amounts of \$358 million and \$324 million, respectively. Neither the DRA nor TURN specified the amount of capital expenditures included in their recommended amounts. On July 23, 2008, the Utility filed a response opposing these recommendations and reaffirming the Utility's support for the requested amounts. A final CPUC decision is expected in December 2008. PG&E Corporation and the Utility cannot predict whether the CPUC will approve the Utility's application for additional funds to upgrade its advanced metering system. The Utility has incurred approximately \$27 million in capital and expense costs for the upgrade as of October 31, 2008 and may incur approximately \$7 million in additional capital and expense costs for the upgrade before the end of the year. If the CPUC does not approve the Utility's request, the Utility may be unable to recover these costs.

On July 31, 2008, the CPUC adopted a decision requiring the Utility to accelerate the deployment of advanced meters and take action to make "dynamic pricing" available to customers in 2010 and 2011. Dynamic pricing will utilize price signals to encourage efficient energy consumption and cost-effective demand response. To meet this accelerated schedule, the Utility will be required to incur additional costs, including costs to design and implement new software and billing systems to integrate the new advanced metering technology. The CPUC has directed the Utility to request recovery of the additional cost required to implement dynamic pricing. The Utility is developing its estimates of the additional costs it will incur to comply with this decision and expects to file a request for cost recovery with the CPUC in early 2009.

Colusa Power Plant

On June 12, 2008, the CPUC gave its final approval for the Utility to construct the Colusa Project, a 657-megawatt ("MW") combined cycle generating facility to be located in Colusa County, California after reviewing the final environmental certification issued by the CEC. Final environmental permitting was approved on September 29, 2008 and construction began on October 1, 2008.

The Utility's recovery of costs related to the Colusa Project is subject to the initial capital cost limits of approximately \$673 million and operations and maintenance ratemaking previously approved by the CPUC. Subject to meeting operational performance requirements and other conditions, it is anticipated that the Colusa Project will commence operations in 2010.

Humboldt Bay Repowering Project

On September 24, 2008, the CEC issued its final decision authorizing the construction of the Humboldt Bay Repowering Project ("HBRP"), a 163 MW reciprocating engine electric generating facility to be located in Humboldt County at the site of the Utility's existing Humboldt Bay Power Plant. Demolition of existing structures on the site is complete and construction will commence during November 2008. Subject to meeting operational performance requirements and other conditions, it is anticipated that the HBRP will commence operations in 2010.

The Utility's recovery of costs related to the HBRP is subject to the initial capital cost limits of approximately \$239 million and operations and maintenance ratemaking previously approved by the CPUC.

Tesla Generating Station

On July 18, 2008, the Utility filed an application requesting that the CPUC authorize the Utility to develop and construct a 560-MW generating unit at the Tesla Generating Station, a proposed combined cycle power plant to be located in eastern Alameda County, California. The Utility had requested that the CPUC authorize the Utility to recover up to \$850 million of forecasted capital costs associated with the construction of the unit. On September 22, 2008, a CPUC administrative law judge issued a proposed decision which recommends that the Utility's application be dismissed on the basis that the Utility's application failed to sufficiently demonstrate that conducting a competitive request for offers ("RFO") would be infeasible.

On October 14, 2008, the Utility filed comments objecting to the proposed decision. The CPUC is expected to issue a final decision by the end of 2008.

Request for New Generation Offers and Potential New Utility-Owned Generation

On July 21, 2008, the Utility received bids from third parties in response to the Utility's April 1, 2008 long-term RFO for 800 to 1,200 MW of dispatchable and operationally flexible new generation resources to be on-line no later than May 2015. The Utility is evaluating these offers and plans to develop a shortlist of offers during the fourth quarter of 2008. The Utility's RFO requested both power purchase agreements and purchase and sale agreements. Under a purchase and sale agreement a new generating facility would be constructed by a third party and then sold to the Utility upon satisfaction of certain contractual requirements.

The Utility conducted a similar RFO in 2004-2005 and, as a result of that process, entered into several power purchase agreements with third parties that are contingent on the third party's development of a new generation facility to provide the power to be purchased by the Utility under the agreement. These agreements were approved by the CPUC in November 2006. Since that time, the development plans for two of the proposed generation facilities have been terminated and the development of a third, the proposed Russell City Energy Center, has been delayed pending CPUC approval of an amendment to the related power purchase agreement.

Proposed Electric Transmission Projects

The Utility has been exploring the feasibility of obtaining regulatory approval for a potential investment in an electric transmission project that would traverse the Pacific Northwest. On April 17, 2008, the FERC granted part of the Utility's request for a declaratory order to collect transmission rates designed to provide an incentive to the Utility to continue leading the development of the proposed 1,000-mile, 500 kilovolt ("kV") transmission line to run from British Columbia, Canada to Northern California that would provide access to potential new renewable generation resources, improve regional transmission reliability, and provide opportunities for other market participants to use the new facilities. The FERC's order allows the Utility to recover all prudently incurred pre-commercial costs, such as costs for feasibility studies and surveys, and all prudently incurred development and construction costs if the proposed project is abandoned or cancelled for reasons beyond the Utility's control. The development and construction of this proposed transmission project remains subject to significant business, financial, regulatory, environmental, and political risks and challenges.

The Utility also has been exploring the development of a new 500-kV electric transmission project, the Central California Clean Energy Transmission line, to increase transmission capacity between northern and southern California and provide needed access to new renewable generation resources. The CAISO has been conducting stakeholder meetings to review the Utility's proposal and the Utility has been conducting various studies to ensure that the project is designed and located to avoid or minimize potential impacts. Depending on the results of these stakeholder meetings and studies, the Utility will decide whether to request CPUC approval to construct the line.

The Utility cannot predict whether the many conditions and challenges to the development of these proposed electric transmission projects will be met.

Potential Natural Gas Pipeline Projects

PG&E Corporation continues to pursue the development of the proposed 230-mile Pacific Connector Gas Pipeline, along with Fort Chicago Energy Partners, L.P. and Northwest Pipeline Corporation. The development of the Pacific Connector Gas Pipeline is dependent upon the development of the Jordan Cove liquefied natural gas terminal by Fort Chicago Partners, L.P. and the satisfaction of other conditions and requirements.

PG&E Corporation also has been exploring potential investments in natural gas transmission pipeline projects, but it has decided not to pursue an investment in El Paso Corporation's proposed Ruby Pipeline. On April 30, 2008, PG&E Corporation terminated the letter of intent it had entered into in December 2007 with El Paso Corporation to acquire an interest in the proposed Ruby Pipeline. On October 7, 2008, the assigned administrative law judge at the CPUC issued a proposed decision that, if adopted by the CPUC, would grant the Utility the authority to enter into a contract for long-term capacity on the proposed Ruby Pipeline for a 15-year term commencing in 2011 when the pipeline is proposed to be placed into service. A final decision is expected on November 6, 2008.

OFF-BALANCE SHEET ARRANGEMENTS

For financing and other business purposes, PG&E Corporation and the Utility maintain certain arrangements that are not reflected in their Condensed Consolidated Balance Sheets. Such arrangements do not represent a significant part of either PG&E Corporation or the Utility's activities or a significant ongoing source of financing. These arrangements enable PG&E Corporation and the Utility to obtain financing or execute commercial transactions on more favorable terms. For further information related to letter of credit agreements and the credit facilities, see the 2007 Annual Report and Note 4 of the Notes to the Condensed Consolidated Financial Statements.

Credit Risk

The Utility conducts business with wholesale customers and counterparties mainly in the energy industry, including other California investor-owned electric utilities, municipal utilities, energy trading companies, financial institutions, and oil and natural gas production companies located in the United States and Canada. If a counterparty failed to perform on its contractual obligation to deliver electricity, then the Utility may find it necessary to procure electricity at current market prices, which may be higher than the contract prices. Credit-related losses attributable to receivables and electric and gas procurement activities from wholesale customers and counterparties are expected to be recoverable from customers through rates and are not expected to have a material impact on net income.

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 September 30, 2008 and December 31, 2007:

(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%
September 30, 2008	\$ 378	\$ 98	\$ 281	2	\$ 159
December 31, 2007	\$ 311	\$ 91	\$ 220	2	\$ 111

⁽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.

On September 15, 2008, Lehman Brothers, Inc. filed a petition under Chapter 11 of the U.S. Bankruptcy Code. The Utility's net credit exposure to various Lehman Brothers, Inc. subsidiaries related to price risk management activity was immaterial.

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

The Utility is subject to substantial regulation. Set forth below are matters pending before the CPUC, the resolution of which may affect PG&E Corporation and the Utility's results of operations or financial condition.

2008 Cost of Capital Proceeding

On May 29, 2008, the CPUC adopted a uniform three-year cost of capital mechanism in the second phase of the 2008 Cost of Capital proceeding for the Utility and the other two California investor-owned electric utilities that will replace the annual cost of capital proceeding. Under the adopted mechanism, the utilities are required to file full cost of capital applications by April 20 of every third year, beginning on April 20, 2010.

Under the decision, the Utility's 2008 cost of capital (including an 11.35% ROE) will be maintained through 2010, unless the automatic adjustment mechanism described below is triggered. The Utility's 2008 capital structure (including a 52% equity component) is authorized through 2010. The decision permits the utilities to apply for an adjustment to either the cost of capital or the capital structure sooner based on extraordinary circumstances.

The cost of capital mechanism uses an interest rate index (the 12-month October through September average of the Moody's Investors Service utility bond index) to trigger changes in the authorized cost of debt, preferred stock, and equity. In any year in which the 12-month October through September average for the index increases or decreases by more than 100 basis points (“deadband”) from the benchmark, the cost of equity will be adjusted by one-half of the difference between the 12-month average and the benchmark. In addition, if the mechanism is triggered, the costs of long-term debt and preferred stock will be adjusted to reflect the actual August month-end embedded costs in that year and forecasted interest rates for variable long-term debt and any new long-term debt and preferred stock forecasted to be issued in the coming

year. The 12-month October 2007 through September 2008 average of the Moody's Investors Service utility bond index did not trigger a change in the authorized cost of debt, preferred stock, or equity for 2009.

Spent Nuclear Fuel Storage Proceeding

As a consequence of the U.S. Department of Energy's ("DOE") failure to develop a permanent national repository for spent nuclear fuel and high-level radioactive waste produced by the nation's nuclear electric generation facilities, the Utility has been storing spent nuclear fuel and high-level radioactive waste resulting from its nuclear operations at Diablo Canyon in on-site storage pools. The Utility believes that the existing spent fuel pools at Diablo Canyon have sufficient capacity to enable the Utility to operate Diablo Canyon until October 2010 for Unit 1 and May 2011 for Unit 2. In addition, the Utility is constructing a dry cask storage facility at Diablo Canyon to store spent nuclear fuel.

The construction of this dry cask storage facility, along with modifications to the power plant to support dry cask storage processing, is not expected to be completed until late 2008 with the initial movement of spent nuclear fuel to dry cask storage beginning in June 2009. If the Utility is unable to complete the facility and load spent fuel into the dry cask storage facility by October 2010 for Unit 1 or May 2011 for Unit 2, the Utility would have to curtail or halt operations in the unit until such time as additional safe storage for spent fuel is made available.

On October 23, 2008, the Nuclear Regulatory Commission ("NRC") issued an order rejecting the final contention made by a party who had appealed the NRC's 2004 decision to grant the Utility a license to construct the dry cask storage facility. The NRC concluded that the NRC staff's supplemental environmental assessment, which concluded there would be no significant environmental impacts from potential terrorist acts directed at the dry cask storage facility, was supported by a reasonable analysis. Any party wishing to appeal the NRC's order must file a notice of appeal within 60 days.

In addition, 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 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 only 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. The Utility expects the final award will approximate \$89 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. After the appellate court denied the DOE's request for an extension of time to file a petition for rehearing, the DOE filed a motion for reconsideration of that order which the appellate court has not yet addressed. On October 30, 2008, the U.S. Court of Federal Claims took notice of the appellate court's order and requested the parties to file a joint status report and proposed schedule for remand litigation by December 1, 2008. 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.

Energy Efficiency Programs and Incentive Ratemaking

The schedule adopted by the CPUC to review and determine whether the Utility and other California investor-owned utilities are entitled to receive shareholder incentive earnings (or whether they will incur reimbursement obligations) based on the 2006-2007 energy efficiency program accomplishments called for the CPUC's Energy Division to issue updated energy savings assumptions and to verify the utilities' installation of energy efficiency measures in time for the utilities to submit interim claims in September 2008. As a result of continuing delays in the issuance of the updated savings assumptions and completion of the Energy Division's verification, on August 15, 2008, the Utility and other investor-owned utilities jointly filed a petition requesting that the CPUC (1) approve the utilities' interim claims for incentives for 2006-2007 programs based on the utilities' reports of their accomplishments submitted to the CPUC in February 2008; (2) verify the utilities' energy savings results for the final true-up claim for the 2006-2008 programs to be submitted in 2010 based on the Energy Division's measurement and evaluation studies to be completed in 2010 but use the reported results submitted by the utilities to assess the interim claims in 2008 and 2009; and (3) adopt a schedule allowing the utilities to recognize earnings (or reimbursement obligations) attributable to their claims annually despite possible delays in the CPUC's process. In the petition the Utility requested the CPUC to approve interim shareholder incentive earnings of \$77 million representing 65% of approximately \$119 million. Per the adopted mechanism, the remaining 35% (\$42 million) would be held back until the completion of evaluation and measurement studies for the final true-up claim in 2010.

On November 4, 2008, a proposed decision was issued by the CPUC administrative law judge ("ALJ") assigned to this proceeding and an alternate proposed decision was issued by the President of the CPUC. The ALJ's proposed decision recommends that the CPUC deny the petition for modification. If the proposed decision is adopted by the CPUC, the utilities' interim claims will not be determined until after the Energy Division issues its final verification report in January 2009 using recent updates to estimates of energy savings from the energy efficiency measures installed by the utilities on customer premises. If the proposed decision is adopted and the updated savings estimates are used to assess the 2006-2007 program results submitted by the Utility in February 2008, it is unlikely that the Utility would receive any incentive earnings in 2008 or 2009 and the Utility could incur a reimbursement obligation which the Utility estimates could be approximately \$14 million.

The alternate proposed decision recommends that the CPUC grant the petition in part and award the Utility interim incentive earnings for 2006-2007 program accomplishments of \$59.3 million in 2008 (50% of approximately \$119 million) and hold back the remaining 50%. The alternate proposed decision recommends that the interim claims to be submitted in 2009 for 2008 program performance be assessed using the recent updated savings estimates and be determined after the Energy Division issues a final verification report on the 2008 program year. If this final verification report is delayed, the alternate proposed decision would permit the 2009 interim claims for the 2008 program year to be based on the utilities' reported results, subject to a holdback of at least 50%. The total amount of incentive claims for the completed three-year program period (2006-2008) would be subject to verification and adjustment based on the results of the measurement and evaluation studies to be completed in 2010.

It is expected that the CPUC will consider both of the proposed decisions at its December 4, 2008 meeting.

On July 21, 2008, the Utility filed its application seeking CPUC approval of the Utility's energy efficiency programs and funding of \$1.87 billion for the 2009-2011 cycle of energy efficiency programs. The CPUC has authorized bridge funding for the Utility to continue offering its existing programs in 2009 until the CPUC issues its final decision on the 2009-2011 energy efficiency application, which is expected in mid-2009. On July 31, 2008, the CPUC issued a decision indicating that energy efficiency savings goals for the 2009-2011 program period will be considered on a gross basis (i.e., without deduction for customer energy savings not directly attributed to utility programs). The CPUC also stated that it would review whether it should modify the incentive ratemaking structure due to the transition from net goals to gross goals for the 2009 and beyond program periods. On October 30, 2008, the CPUC assigned commissioner and the ALJ issued a ruling requiring the Utility and other investor-owned utilities to re-file their proposed 2009-2011 energy efficiency programs by a date no earlier than January 15, 2009, in order to take into account the recent updated energy savings estimates.

The amount of any shareholder incentives the Utility may receive (and the amount and timing of any reimbursement obligations the Utility may incur) for the 2009-2011 program cycle will depend on whether the Utility can design 2009-2011 programs that will meet the CPUC's energy savings goals based on the recently revised estimates of energy savings; whether the CPUC changes the incentive structure; and the level of energy efficiency savings actually achieved over the three-year program cycle.

Application to Recover Hydroelectric Generation Facility Divestiture Costs

On April 14, 2008, the Utility filed an application with the CPUC requesting authorization to recover approximately \$47 million, including \$12.2 million of interest, of the costs it incurred in connection with the Utility's efforts to determine the market value of its hydroelectric generation facilities in 2000 and 2001. These efforts were undertaken at the direction of the CPUC in preparation for the planned divestiture of the facilities to further the development of a competitive generation market in California. In 2003, the CPUC determined that the amount of these costs at the time, \$34.8 million, was reasonable and authorized the Utility to track these costs and seek authorization to recover these costs in the future if the hydroelectric generation facilities were ultimately not divested. The Utility continues to own its hydroelectric generation assets. On May 19, 2008, the DRA filed a protest to the Utility's application. On August 14, 2008, the DRA and the Utility agreed that the Utility had supported its request with appropriate and reasonable evidence. PG&E Corporation and the Utility are unable to predict whether the CPUC will approve recovery of these costs.

Electric Transmission Owner Rate Cases

On October 22, 2008, the FERC approved an all-party settlement in the Utility's TO rate case that was filed in July 2007. The settlement sets an annual wholesale base transmission revenue requirement of \$706 million and a retail base transmission revenue requirement of \$718 million, effective March 1, 2008. 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 will not impact the Utility's results of operations or financial condition. The Utility will refund any over-collected amounts to customers, with interest, through an adjustment to rates in 2010.

Also, on September 30, 2008, the FERC accepted the Utility's TO rate case that was filed on July 30, 2008 requesting an increase in retail base revenue requirement, to \$849 million, and an increase in the Utility's wholesale base revenue requirement to \$838 million. As customary, the FERC suspended the rate increase associated with the requested increase in revenue requirements for five months, until March 1, 2009. The increase in rates will be subject to refund pending final FERC approval of the requested increase in revenue requirements.

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. For a comprehensive discussion of PG&E Corporation's market risk, see the section entitled "Risk Management Activities" in the 2007 Annual Report.

Price Risk

Electric Transmission Congestion Rights

Among other features, the CAISO's Market Redesign and Technology Upgrade ("MRTU") initiative provides that electric transmission congestion costs and credits will be determined between any two locations and charged to the market participants, including load

serving entities, taking energy that passes between those locations. The CAISO also will provide Congestion Revenue Rights (“CRRs”) to allow market participants, including load serving entities, to hedge the financial risk of CAISO-imposed congestion charges in the MRTU day-ahead market. 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) and an auction phase (priced at market, and available to all market participants).

The Utility has been allocated and has acquired via auction certain CRRs as of September 30, 2008, and anticipates acquiring additional CRRs through the allocation and auction phases prior to the MRTU effective date. Currently, the CAISO is targeting an MRTU implementation date of February 1, 2009. The CAISO Board of Governors will continue to evaluate whether that implementation date remains feasible as it approaches. During the fourth quarter of 2007, the Utility participated in an auction to acquire additional firm electricity transmission rights ("FTRs") in order to hedge its financial risk until the MRTU becomes effective.

Natural Gas Transportation and Storage

The Utility uses value-at-risk to measure the 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 \$31 million at September 30, 2008. The Utility's high, low, and average values-at-risk during the nine months ended September 30, 2008 were approximately \$34 million, \$17 million, and \$26 million, respectively.

Convertible Subordinated Notes

At September 30, 2008, PG&E Corporation had outstanding approximately \$280 million of 9.50% Convertible Subordinated Notes that are scheduled to mature on June 30, 2010. Interest is payable semi-annually in arrears on June 30 and December 31. These Convertible Subordinated Notes may be converted (at the option of the holder) at any time prior to maturity into 18,558,059 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 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, 2008, PG&E Corporation has paid "pass-through dividends" totaling approximately \$28 million, including \$7 million paid on October 15, 2008.

In accordance with Statement of Financial Accounting Standards ("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. Dividend participation rights are recognized as operating cash flows in PG&E Corporation's Condensed Consolidated Statements of Cash Flows. Changes in the fair value are recognized (in Other income (expense), net) in PG&E Corporation's Condensed Consolidated Statements of Income as a non-operating expense or income. At September 30, 2008, the total estimated fair value of the dividend participation rights, on a pre-tax basis, was approximately \$49 million, of which \$28 million was classified in Current Liabilities - Other and \$21 million was classified in Noncurrent Liabilities - Other in the accompanying Condensed Consolidated Balance Sheets. At December 31, 2007, the total estimated fair value of the dividend participation rights, on a pre-tax basis, was approximately \$62 million, of which \$25 million was classified in Current Liabilities - Other and \$37 million was classified in Noncurrent Liabilities - Other in the accompanying Condensed Consolidated Balance Sheets. The discount factor used to value these rights was adjusted on January 1, 2008 in order to comply with the provisions of SFAS No. 157 "Fair Value Measurements" ("SFAS No. 157"), resulting in a \$6 million increase in fair value. (See Note 8 of the Notes to the Condensed Consolidated Financial Statements for further discussion of the implementation of SFAS No. 157.)

Interest Rate Risk

Interest rate risk sensitivity analysis is used to measure interest rate risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. At September 30, 2008, 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 nine months ended September 30, 2008 by approximately \$7.1 million, based on net variable rate debt and other interest rate-sensitive instruments outstanding.

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 2007 Annual Report. They include:

- regulatory assets and liabilities;
- unbilled revenues;
- environmental remediation liabilities;
- asset retirement obligations;
- income taxes; and
- pension and other postretirement benefits.

On January 1, 2008, PG&E Corporation and the Utility adopted the provisions of SFAS No. 157, (see “New Accounting Policies” below and Note 2 and Note 8 of the Notes to the Condensed Consolidated Financial Statements for further discussion), which are also considered critical accounting policies. Additionally, PG&E Corporation and the Utility adopted the provisions of Financial Accounting Standards Board (“FASB”) Staff Position on Interpretation 39, “Amendment of FASB Interpretation No. 39” (see Note 2 of the Notes to the Condensed Consolidated Financial Statements for further discussion).

For the period ended September 30, 2008, 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

Fair Value Measurements

On January 1, 2008, PG&E Corporation and the Utility adopted the provisions of SFAS No. 157. SFAS No. 157 establishes a fair value hierarchy that prioritizes inputs to valuation techniques used to measure fair value. The objective of a fair value measurement is to determine the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, or the “exit price.” The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). Assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. (See Notes 2 and 8 of the Notes to the Condensed Consolidated Financial Statements for further discussion on SFAS No. 157.)

Level 3 Instruments at Fair Value

As Level 3 measurements are based on unobservable inputs, significant judgment may be used in the valuation of these instruments. Accordingly, the following table sets forth the fair values of instruments classified as Level 3 within the fair value hierarchy, along with a brief description of the valuation technique for each type of instrument:

(in millions)	Value as of	
	September 30, 2008	January 1, 2008
Money market investments (held by PG&E Corporation)	\$ 62	\$ -
Nuclear decommissioning trusts	7	8
Price risk management instruments	34	115
Long term disability trust	79	69
Dividend participation rights	(49)	(68)
Other	(5)	(4)
Total Level 3 Instruments	<u>\$ 128</u>	<u>\$ 120</u>

Level 3 fair value measurements represent approximately 5% of the total net value of all fair value measurements of PG&E Corporation. During the three and nine months ended September 30, 2008, there were no material increases or decreases in Level 3 assets or liabilities resulting from a transfer of assets or liabilities from, or into, Level 1 or Level 2. The majority of these instruments are accounted for in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," as amended, as they are expected to be recovered or refunded through regulated rates. Therefore, changes in the aggregate fair value of these assets and liabilities (including realized and unrealized gains and losses) are recorded within regulatory accounts in the accompanying Condensed Consolidated Balance Sheets with the exception of the dividend participation rights associated with PG&E Corporation's Convertible Subordinated Notes. The changes in the fair value of the dividend participation rights are reflected in Other income (expense), net in PG&E Corporation's Condensed Consolidated Statements of Income. Additionally, changes in the fair value of the Level 3 instruments did not have a material effect on liquidity and capital resources as of September 30, 2008.

Money Market Investments

PG&E Corporation invests in AAA-rated money market funds that seek to maintain a stable net asset value. These funds invest in high quality, short-term, diversified money market instruments, such as treasury bills, federal agency securities, certificates of deposit and commercial paper with a maximum weighted average maturity of 60 days or less. PG&E Corporation's investments in these money market funds are generally valued based on observable inputs such as expected yield and credit quality and are thus classified as Level 1 instruments. Approximately \$192 million held in money market funds are recorded as Cash and cash equivalents in PG&E Corporation's Condensed Consolidated Balance Sheets.

As of September 30, 2008, PG&E Corporation classified approximately \$62 million invested in one money market fund as a Level 3 instrument because the fund manager imposed restrictions on fund participants' redemption requests. PG&E Corporation's investment in this money market fund, previously recorded as Cash and cash equivalents, is recorded as Prepaid expenses and other in PG&E Corporation's Condensed Consolidated Balance Sheets. (In October 2008, PG&E Corporation received an initial redemption amount of approximately \$32 million from the money market fund.)

Nuclear Decommissioning Trusts and Long Term Disability Trust

The nuclear decommissioning trusts and the long-term disability trust primarily hold equities, debt securities, mutual funds, and life insurance policies. These instruments are generally valued based on unadjusted prices in active markets for identical transactions or unadjusted prices in active markets for similar transactions. The nuclear decommissioning trusts and the long-term disability trust also invest in long-term commingled funds, which are funds that consist of assets from several accounts that are intermingled. These commingled funds have liquidity restrictions and lack an active market for individual shares of the funds; therefore the trusts' investments in these funds are classified as Level 3. The Level 3 nuclear decommissioning trust assets decreased from approximately \$8 million at January 1, 2008 to approximately \$7 million at September 30, 2008 and no material change was noted from June 30, 2008 to September 30, 2008. The decrease of approximately \$1 million for the nine months ended September 30, 2008 was primarily due to unrealized losses of these commingled fund investments. The Level 3 long-term disability trust assets increased from approximately \$69 million at January 1, 2008 to approximately \$79 million at September 30, 2008. This increase of approximately \$10 million for the nine months ended September 30, 2008 was primarily due to net purchases of commingled fund investments, offset by unrealized losses on these investments. Additionally, the Level 3 long-term disability trust assets decreased from approximately \$95 million at June 30, 2008 to approximately \$79 million at September 30, 2008. This decrease of approximately \$16 million for the three months ended September 30, 2008 was primarily due to net sales of commingled fund investments and unrealized losses on these investments.

Price Risk Management Instruments

The price risk management instrument category is comprised of physical and financial derivative contracts including futures, forwards, options, and swaps that are both exchange-traded and over-the-counter ("OTC") traded contracts. When necessary, PG&E Corporation and the Utility generally use similar models to value similar instruments. Since the Utility's contracts are used within the regulatory framework, regulatory accounts are recorded to offset the associated gains and losses of these derivatives, which will be reflected in future rates. The Level 3 price risk management instruments decreased from approximately \$115 million as of January 1, 2008 to approximately \$34 million as of September 30, 2008. This decrease of approximately \$81 million was primarily due to a decrease in commodity prices on September 30, 2008 as compared to January 1, 2008. Additionally, the Level 3 price risk management instruments decreased from approximately \$382 million as of June 30, 2008 to approximately \$34 million at September 30, 2008. This decrease of approximately \$348 million was primarily due to a decrease in commodity prices on September 30, 2008, as compared to June 30, 2008.

Type of Instrument	Value (in millions)	
	September 30, 2008	January 1, 2008
Options (exchange-traded and OTC)	\$ 32	\$ 50
Congestion revenue rights, Firm transmission rights, and Demand response	69	61
Swaps and forwards	(221)	(2)
Netting and collateral	154	6
Total	<u>\$ 34</u>	<u>\$ 115</u>

All options (exchange-traded and OTC) are valued using the Black's Option Pricing Model and classified as Level 3 measurements primarily due to volatility inputs. The Utility receives implied volatility for options traded on exchanges which may be adjusted to incorporate the specific terms of the Utility's contracts, such as strike price or location.

CRRs, FTRs, and demand response contracts are new and/or complex instruments that have immature or limited markets. CRRs allow market participants, including load serving entities, to hedge financial risk of CAISO-imposed congestion charges in the day-ahead market to be established when MRTU becomes effective. FTRs allow market participants, including load serving entities to hedge both the physical and financial risk associated with CAISO-imposed congestion charges until the MRTU becomes effective. Demand response contracts allow market participants, including load serving entities, to hedge financial risk associated with increased energy prices resulting from increased demand on the electricity grid. As the markets for these instruments have minimal activity, observable inputs may not be available in pricing these instruments. Therefore, the pricing models used to value these instruments often incorporate significant estimates and assumptions that market participants would use in pricing the instrument. Accordingly, they are classified as Level 3 measurements. When available, observable market data is used to calibrate pricing models.

The remaining Level 3 price risk management instruments are OTC derivative instruments that are valued using pricing models based on the net present value of estimated future cash flows based on broker quotations. The Utility receives multiple non-binding broker quotes for certain locations which are generally averaged for valuation purposes. In certain circumstances, broker quotes may be interpolated or extrapolated to fit the terms of a contract, such as frequency of settlement or tenor. These instruments are classified within Level 3 of the fair value hierarchy.

Dividend Participation Rights

The dividend participation rights of the Convertible Subordinated Notes are embedded derivative instruments in accordance with SFAS No. 133 and, therefore, are bifurcated from the Convertible Subordinated Notes and recorded at fair value in PG&E Corporation's Condensed Consolidated Balance Sheets. The dividend participation rights are valued based on the net present value of estimated future cash flows using internal estimates of common stock dividends. These rights are recorded as Current Liabilities-Other and Noncurrent Liabilities-Other in PG&E Corporation's Condensed Consolidated Balance Sheets. (See Note 4 of the Notes to the Condensed Consolidated Financial Statements for further discussion of these instruments.)

Nonperformance Risk

In accordance with SFAS No. 157, PG&E Corporation and the Utility incorporate the risk of nonperformance into the valuation of their fair value measurements. Nonperformance risk adjustments on the Utility's price risk management instruments are based on current market inputs when available, such as credit default swaps spreads. When such information is not available, internal models may be used. The nonperformance risk adjustment for the net price risk management instruments contributed less than 1% of the value on June 30, 2008 and increased to approximately 1% of the value on September 30, 2008. As the Utility's contracts are used within the regulatory framework, the nonperformance risk adjustments are recorded to regulatory accounts and do not impact earnings.

See Notes 2 and 8 of the Notes to the Condensed Consolidated Financial Statements for further discussion on other new accounting policies.

ACCOUNTING PRONOUNCEMENTS ISSUED BUT NOT YET ADOPTED

Disclosures about Derivative Instruments and Hedging Activities - an amendment of Financial Accounting Standards Board ("FASB") Statement No. 133

In March 2008, the FASB issued 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. An entity is required to provide qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures on fair value amounts of and gains and losses on derivative instruments, and disclosures relating to credit-risk-related contingent features in derivative agreements. SFAS No. 161 is effective prospectively for fiscal years beginning after November 15, 2008. PG&E Corporation and the Utility are currently evaluating the impact of SFAS No. 161.

ITEM 3: QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PG&E Corporation 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 the "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 and the Utility's disclosure controls and procedures as of September 30, 2008, PG&E Corporation 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 the companies file or submit under the Securities and Exchange Act of 1934 ("the Act") is recorded, processed, summarized, and reported within the time periods specified in the SEC rules and forms. In addition, PG&E Corporation 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 Act is accumulated and communicated to PG&E Corporation and the Utility's management, including PG&E Corporation 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 controls over financial reporting that occurred during the quarter ended September 30, 2008 that have materially affected, or are reasonably likely to materially affect, PG&E Corporation or the Utility's internal controls over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Solano County District Attorney's Office

For more information regarding the resolution of this matter, see "PART II, Item 1. Legal Proceedings" in PG&E Corporation and Pacific Gas and Electric Company's ("Utility") combined Quarterly Report on Form 10-Q for the quarter ended March 31, 2008.

ITEM 1A. RISK FACTORS

The discussion of the Utility's efforts to store spent nuclear fuel appearing in the 2007 Annual Report under the heading "Management's Discussion and Analysis of Financial Condition and Results of Operations – Risk Factors" under the following caption "***The operation and decommissioning of the Utility's nuclear power plants expose it to potentially significant liabilities and capital expenditures that it may not be able to recover from its insurance or other source, adversely affecting its financial condition, results of operations, and cash flow***" is updated as follows to reflect the new date that the Utility expects it will begin loading spent fuel into the dry cask storage facility:

Because the U.S. Department of Energy has failed to develop a permanent national repository for the nation's spent nuclear fuel and high-level radioactive waste produced by the nation's nuclear electric generation facilities, the Utility has been storing spent nuclear fuel and high-level radioactive waste resulting from its nuclear operations at Diablo Canyon nuclear generating facilities ("Diablo Canyon") in on-site storage pools. The Utility believes that the existing spent fuel pools at Diablo Canyon have sufficient capacity to enable the Utility to operate Diablo Canyon until October 2010 for Unit 1 and May 2011 for Unit 2. The Utility is also constructing a dry cask storage facility at Diablo Canyon to store spent nuclear fuel which it expects to complete by the end of 2008.

Although the Utility expected to begin loading spent nuclear fuel in 2008, the Utility currently expects that the dry cask storage facility and modifications to the power plant to support dry cask storage processing will be completed in late 2008 and that the initial movement of spent nuclear fuel into dry storage will begin in June 2009. If the Utility is unable to complete the facility and load spent fuel into the dry cask storage facility by October 2010 for Unit 1 or May 2011 for Unit 2, the Utility would have to curtail or halt operations of the unit until such time as additional safe storage for spent fuel is made available.

On October 23, 2008, the Nuclear Regulatory Commission ("NRC") issued an order rejecting the final contention made by a party who had appealed the NRC's 2004 decision to grant the Utility a license to construct the dry cask storage facility. The NRC concluded that the NRC staff's supplemental environmental assessment, which concluded there would be no significant environmental impacts from potential terrorist acts directed at the dry cask storage facility, was supported by a reasonable analysis. Any party wishing to appeal the NRC's order must file a notice of appeal within 60 days.

The discussion under the heading "Management's Discussion and Analysis of the Financial Condition and Results of Operations - Risk Factors" in the 2007 Annual Report under the following caption "***The Utility relies on access to the capital markets. There can be no assurance that the Utility will be able to successfully finance its planned capital expenditures on favorable terms or rates***" is updated as follows to reflect the recent events in the financial markets:

The Utility's ability to make scheduled principal and interest payments, refinance debt, fund operations, deposit collateral in connection with its natural gas and electricity procurement hedging contracts, and make planned capital expenditures, depends on the levels of its operating cash flow and access to the capital markets. Like many companies, the Utility relies on the capital markets to fund its daily operations with commercial paper, and to fund its significant capital expenditure plan with long-term debt and equity. The Utility's ability to access the capital markets and the costs and terms of available financing depend on many factors, including changes in the Utility's credit ratings, changes in the federal or state regulatory environment affecting energy companies, volatility in electricity or natural gas prices, and general economic and market conditions. The recent financial distress experienced at major financial institutions has caused significant disruption in the capital markets, particularly in the commercial paper market where short-term rates have increased significantly and access generally has contracted. Long-term debt rates on utility bond issuances also have increased significantly since mid-September and the volume of utility bond issuances has decreased. The longer such conditions persist, the more significant the implications become for the Utility, including the potential that adequate capital is not available to fund the Utility's operations and planned capital expenditures. If the Utility is unable, in part or in whole, to fund its operations and planned capital expenditures there could be a material adverse effect on PG&E Corporation and the Utility's results of operations, cash flows and financial condition.

In addition, if the Utility were unable to access the capital markets, the Utility may need to consider additional options, such as decreasing or suspending dividend payments to PG&E Corporation. PG&E Corporation also would need to consider its alternatives, such as contributing capital to the Utility to enable the Utility to fulfill its obligation to serve. These alternatives would be evaluated in the context of market conditions then-prevailing, prudent financial management, and any applicable regulatory requirements.

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

During the third quarter of 2008, PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. During the third quarter of 2008, the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding. On July 25, 2008, PG&E Corporation contributed equity of \$40 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.

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 and nine months ended September 30, 2008 was 3.33 and 2.99, respectively. The Utility's earnings to combined fixed charges and preferred stock dividends ratio for the three and nine months ended September 30, 2008 was 3.27 and 2.94, respectively. 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.

ITEM 6. EXHIBITS

- 4 Fourth Supplemental Indenture dated as of October 21, 2008 relating to the Utility's issuance of \$600,000,000 aggregate principal amount of its 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company's Current Report on Form 8-K dated October 21, 2008 (File No. 1-2348), Exhibit 4.1)
- 10* Separation Agreement between William T. Morrow and Pacific Gas and Electric Company dated July 8, 2008
- 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
- 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, Chief Financial Officer, and Treasurer
(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: November 6, 2008

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.

SEPARATION AGREEMENT

This Separation Agreement (this "Agreement") is made and entered into by and between William T. Morrow (the "Executive") and Pacific Gas and Electric Company (the "Company") (collectively the "Parties") and sets forth the terms and conditions of the Executive's separation from employment with the Company. The "Effective Date" of this Agreement is defined in paragraph 18(a).

1. **Resignation.** Effective August 31, 2008 (the "Resignation Date"), the Executive hereby resigns from his positions as Chief Executive Officer and President and a member of the Board of Directors of the Company, and resigns from employment with the Company and from each other position he holds with any of its affiliates, including as a director of any such entity. Promptly after his Resignation Date, he will be paid all salary or wages and vacation accrued, unpaid and owed to him as of the Resignation Date, he will remain entitled to any other benefits to which he is otherwise entitled as of the Resignation Date under the provisions of the Company's plans and programs, and he will receive notice of the right to continue his existing health-insurance coverage pursuant to COBRA. The Executive shall make a diligent search for, and deliver to the Company, by the Resignation Date (i) any document, materials, files or computer files, or copies, reproductions, duplicates, transcriptions or replicas thereof relating to the Company's business or affairs or belonging to the Company or any of its affiliates, which are in his possession or control and (ii) all other Company property (including, without limitation, laptop computer, blackberry, identification cards, security access cards, etc.), which are in his possession or control.

The continuation of wages and other compensation set forth in paragraph 2 below is conditioned upon the Executive's acceptance of this Agreement.

2. **Continued pay and service credit.** To induce the Executive to resign as of the Resignation Date and for other consideration set forth herein, the Company will provide to the Executive, or his estate, the following compensation benefits conditioned upon the occurrence of the Effective Date of this Agreement as set forth in paragraph 18(a) below:

a. **Salary continuation and bonus payment.** Subject to his compliance with the terms and conditions of this Agreement, from the Resignation Date and continuing until January 31, 2009, the Company shall continue to pay the Executive monthly payments equal to the same monthly base salary that it would have paid him had he continued to be employed through January 31, 2009, at the same time and on the same conditions as though he had continued to be employed by the Company. In addition, the Company will pay the Executive his target participation in PG&E Corporation's Short-Term Incentive Plan ("STIP") of \$584,375 for 2008, multiplied by the final 2008 STIP rate as determined by the PG&E Corporation's Compensation Committee of the Board of Directors, less applicable withholdings and deductions, payable in or about March 2009 in accordance with the Company's current pay practices.

b. **Continued Service Credit for Equity Awards.** Subject to his

compliance with the terms and conditions of this Agreement, the Company shall provide the Executive service credit from the Resignation Date to January 31, 2009 for purposes of vesting in restricted stock grants and performance share grants provided to the Executive under PG&E Corporation's 2006 Long-Term Incentive Plan ("LTIP") (including, without limitation, the restricted stock grants vesting on January 2, 2009 and January 29, 2009) in accordance with the terms of the restricted stock agreements and performance share agreements relating to such grants, provided, however, that all restricted stock grants and performance share grants that would not have vested as of January 31, 2009 based upon the vesting schedules set forth in such restricted stock agreements and performance share agreements shall be forfeited effective as of the Effective Date. The Executive shall not be eligible to receive (i) any incentive compensation for any period after December 31, 2008 or (ii) any additional equity awards from and after the Resignation Date.

c. **Other benefits.** Any benefits accrued under the PG&E Corporation Supplemental Executive Retirement Plan ("SERP") as of the Resignation Date shall be paid in accordance with the terms of such plan, and no additional benefits shall accrue under SERP after the Resignation Date. In accordance with the terms of the PG&E Corporation's Executive Stock Ownership Program, the Executive will not be entitled to any Special Incentive Stock Ownership Premiums ("SISOPs") and therefore will not be awarded any SISOPs. The Executive will be eligible for COBRA continuation coverage from the Resignation Date to the extent available to him at law. The Company will pay all COBRA premiums on behalf of the Executive and his family through January 31, 2009, provided that the Executive makes a COBRA election to continue said benefits on a timely basis. The Company further agrees to promptly reimburse the Executive for all out-of-pocket expenses incurred in the performance of his responsibilities as an officer or director of the Company pursuant to the Company's reimbursement policies in effect as of the time of submission. The Executive shall not be eligible for any benefits under the PG&E Corporation Officer Severance Policy not otherwise specifically provided for herein.

d. **Other employment or consulting.** Provided that the Executive does not take a position with or perform services for a direct competitor of the Company prior to January 31, 2009, the Executive shall not lose any of the benefits set forth in this Agreement based on the fact that he provides consulting services or accepts a job with a different employer after the Resignation Date, but before January 31, 2009. This paragraph 2(d) shall not affect the Executive's obligations under paragraph 7.

3. **Defense and indemnification in third-party claims.** The Company and/or its parent, affiliate, or subsidiary will provide the Executive with legal representation and indemnification protection in any legal proceeding in which he is a party or is threatened to be made a party by reason of the fact that he is or was an employee or officer of the Company and/or its parent, affiliate or subsidiary, in accordance with the terms of the resolution of the Board of Directors of the Company dated July 19, 1995, as well as otherwise required by law.

4. **Cooperation.**

a. The Executive will, upon reasonable notice, furnish information and proper assistance to the Company and/or its parent, affiliate or subsidiary (including truthful

testimony and document production) as may reasonably be required by them or any of them in connection with any legal, administrative or regulatory proceeding or investigation (internal or external) in which they or any of them is, or may become, a party, or in connection with any filing or similar obligation imposed by any taxing, administrative or regulatory authority having jurisdiction, provided, however, that the Company and/or its parent, affiliate or subsidiary will pay all reasonable out-of-pocket expenses incurred by the Executive in complying with this paragraph.

b. Until the Resignation Date, the Executive will, as requested by the Company or Chairman, Chief Executive Officer and President of PG&E Corporation, (i) continue to devote his best skill and perform his duties as Chief Executive Officer and President and a member of the board of directors of the Company (including, without limitation, in connection with fulfilling the Company's reporting obligations to the Securities and Exchange Commission), (ii) cooperate and participate in employee meetings, and (iii) cooperate in communications with media, investment community, regulators, elected officials, other policymakers, government officials and other stakeholders.

5. Release of claims and covenant not to sue.

a. In consideration of the payments and other benefits the Company is providing under this Agreement, the Executive, on behalf of himself and his representatives, agents, heirs and assigns, waives, releases, discharges and promises never to assert any and all claims, liabilities or obligations of every kind and nature, whether known or unknown, suspected or unsuspected that he ever had, now has or might have as of the Effective Date against the Company or its predecessors, parent, affiliates, subsidiaries, shareholders, owners, directors, officers, employees, agents, attorneys, successors, or assigns. These released claims include, without limitation, any claims arising from or related to the Executive's employment with the Company, its parent or any of its affiliates and subsidiaries, and the termination of that employment. These released claims also specifically include, but are not limited, any claims arising under any federal, state and local statutory or common law, such as (as amended and as applicable) Title VII of the Civil Rights Act, the Age Discrimination in Employment Act, the Americans With Disabilities Act, the Employee Retirement Income Security Act, the California Fair Employment and Housing Act, the California Labor Code, any other federal, state or local law governing the terms and conditions of employment or the termination of employment, and the law of contract and tort; and any claim for attorneys' fees.

b. The Executive acknowledges that there may exist facts or claims in addition to or different from those which are now known or believed by him to exist. Nonetheless, this Agreement extends to all claims of every nature and kind whatsoever, whether known or unknown, suspected or unsuspected, past or present, and the Executive specifically waives all rights under Section 1542 of the California Civil Code which provides that:

A GENERAL RELEASE DOES NOT EXTEND TO CLAIMS WHICH THE CREDITOR DOES NOT KNOW OR SUSPECT TO EXIST IN HIS OR HER FAVOR AT THE TIME OF EXECUTING THE RELEASE, WHICH IF KNOWN TO HIM OR HER MUST HAVE MATERIALLY AFFECTED HIS OR

HER SETTLEMENT WITH THE DEBTOR.

c. With respect to the claims released in the preceding paragraphs, the Executive will not initiate or maintain any legal or administrative action or proceeding of any kind against the Company or its predecessors, parent, affiliates, subsidiaries, shareholders, owners, directors, officers, employees, agents, attorneys, successors, or assigns, for the purpose of obtaining any personal relief, nor (except as otherwise required or expressly permitted by law) assist or participate in any such proceedings, including any proceedings brought by any third parties.

d. The Executive agrees to reconfirm the release and covenants set forth herein by executing and returning the attached Exhibit A within 30 days after the Resignation Date. The Company shall be under no obligation to pay any obligation to the Executive accruing after the Resignation Date absent the Executive's signature and return of the Exhibit A to the Company, unless otherwise required by law. In the event the Executive should die or become legally incapacitated prior to executing and returning the attached Exhibit A, a release similar to that set forth in Exhibit A executed by the Executive's estate or legal representative will be sufficient to obligate the Company to pay all remaining obligations or benefits.

6. **Non-disclosure.** The Executive will not use, disclose, publicize, or circulate any confidential, non-public or proprietary information concerning the Company or its subsidiaries or affiliates, which has come to his attention during his employment with the Company, unless doing so is expressly authorized in writing by the PG&E Corporation's Chief Legal Officer, or is otherwise required or expressly permitted by law. Before making any legally-required disclosure, the Executive will give the Company notice at least ten (10) business days in advance.

7. **No unfair competition.**

a. The Executive will not engage in any unfair competition against the Company, its parent or any of its subsidiaries or affiliates.

b. For a period of one year after the Effective Date, the Executive will not, directly or indirectly, solicit or contact for the purpose of diverting or taking away or attempt to solicit or contact for the purpose of diverting or taking away:

- (1) any existing customer of the Company or its parent, affiliates or subsidiaries;
- (2) any prospective customer of the Company or its parent, affiliates or subsidiaries about whom the Executive acquired information as a result of any solicitation efforts by the Company or its parent, affiliates or subsidiaries, or by the prospective customer, during the Executive's employment with the Company;
- (3) any existing vendor of the Company or its parent, affiliates or subsidiaries;

- (4) any prospective vendor of the Company or its parent, affiliates or subsidiaries, about whom the Executive acquired information as a result of any solicitation efforts by the Company or its parent, affiliates or subsidiaries, or by the prospective vendor, during the Executive's employment with the Company;
- (5) any existing employee, agent or consultant of the Company or its parent, affiliates or subsidiaries, to terminate or otherwise alter, or interfere with, the person's or entity's employment, agency or consultant relationship with the Company or its parent, affiliates or subsidiaries; or
- (6) any existing employee, agent or consultant of the Company or its parent, affiliates or subsidiaries, to work in any capacity for or on behalf of any person, company or other business enterprise that is in competition with the Company or its parent, affiliates or subsidiaries.

8. **Material breach by Employee.** In the event that the Executive breaches any material provision of this Agreement, including but not necessarily limited to paragraphs 4, 5, 6, and/or 7, the Company may cease paying or providing any unpaid amounts or benefits (including, without limitation, continued salary payments and vesting of restricted stock grants and performance share grants) specified in this Agreement, except as otherwise required by law or subsequently determined to be due and owing pursuant to arbitration and a determination of an appropriate offset, if any, based on established liability and damages. Subject to the Company's establishment of breach and proof of damages, the Company shall also be entitled to the return of any and all amounts or benefits (including, without limitation, continued salary payments and vesting of restricted stock grants and performance share grants) previously paid or provided to him under this Agreement not otherwise required by law. Despite any breach by the Executive, his other duties and obligations under this Agreement, including his waivers and releases, will remain in full force and effect. In the event of a breach or threatened breach by the Executive of any of the provisions in paragraphs 4, 5, 6, and/or 7, the Company will, in addition to any other remedies provided in this Agreement, be entitled to equitable and/or injunctive relief and, because the damages for such a breach or threatened breach will be difficult to determine and will not provide a full and adequate remedy, the Company will also be entitled to specific performance by the Executive of his obligations under paragraphs 4, 5, 6, and/or 7, without any requirement to post any bond, which is hereby expressly waived by the Executive.

9. **Material breach by the Company.** The Executive will be entitled to recover actual damages in the event of any material breach of this Agreement by the Company, including any unexcused late or non-payment of any amounts owed under this Agreement, or any unexcused failure to provide any other benefits specified in this Agreement. In the event of a breach or threatened breach by the Company of any of its material obligations to him under this Agreement, the Executive will be entitled to seek, in addition to any other remedies provided in this Agreement, specific performance of the Company's obligations and any other applicable equitable or injunctive relief. Despite any breach by the Company, its other duties and

obligations under this Agreement will remain in full force and effect.

10. **No admission of liability.** This Agreement is not, and will not be considered, an admission of liability or a violation of any applicable contract, law, rule, regulation, or order of any kind.

11. **Non-Disparagement.** The Executive agrees to refrain from performing any act, engaging in any conduct or course of action or making or publishing any statements, claims, allegations or assertions, which have or may reasonably have the effect of demeaning the name or business reputation of PG&E Corporation or any of its subsidiaries or affiliates, or any of their respective employees, officers, directors, agents or advisors in their capacities as such or which adversely affects (or may reasonably be expected adversely to affect) the best interests (economic or otherwise) of any of them. The Company agrees to refrain from performing any act, engaging in any conduct or course of action or making or publishing any statements, claims, allegations or assertions in any print, electronic or television media or in investor conference calls or webcasts, which have or may reasonably have the effect of demeaning the name or business reputation of the Executive. The Company further agrees to instruct the members of the Company's Board of Directors, Peter Darbee, and all of the Company's Chief Executive Officers, Chief Operating Officers, Presidents, Senior Vice Presidents and Vice Presidents (in each case, while such person remains a Board member or employee of the Company) to comply with the Company's obligations under this paragraph. In the event that Peter Darbee, or the Company's Chief Legal Officer or Head of Human Resources acquires actual knowledge that a violation of the Company's obligations under this paragraph 11 has occurred, the Company shall take reasonable action to reprimand and further discourage such behavior in violation of this paragraph 11. Each Party agrees that nothing in this paragraph 11 shall preclude the other Party from fulfilling any duty or obligation that he or it may have at law, from responding to any subpoena or official inquiry from any court or government agency, including providing truthful testimony, documents subpoenaed or requested or otherwise cooperating in good faith with any proceeding or investigation, or from taking any reasonable actions to enforce such party's rights under this Agreement in accordance with the dispute resolution provisions specified in paragraph 14 hereof. Each Party shall continue to comply with its or his obligations under this Paragraph 11 regardless of any alleged breach by the other Party of its or his agreements contained in this paragraph 11 unless and until there has been a final determination by a court or an arbitration panel that the other Party has breached its or his obligations under this paragraph 11.

12. **Complete agreement.** This Agreement sets forth the entire agreement between the Parties pertaining to the subject matter of this Agreement and fully supersedes any prior or contemporaneous negotiations, representations, agreements, or understandings between the Parties with respect to any such matters, whether written or oral (including any that would have provided the Executive with any different benefits or payments). The Parties acknowledge that they have not relied on any promise, representation or warranty, express or implied, not contained in this Agreement. Parol evidence will be inadmissible to show agreement by and among the Parties to any term or condition contrary to or in addition to the terms and conditions contained in this Agreement.

13. **Severability.** If any provision of this Agreement is determined to be invalid,

void, or unenforceable, the remaining provisions will remain in full force and effect except that, should paragraphs 4, 5, 6, and/or 7 be held invalid, void or unenforceable, either jointly or separately, the Company will be entitled to rescind the Agreement and/or recover from the Executive any payments made and benefits provided to him under this Agreement.

14. **Dispute Resolution.** With the exception of any request for specific performance, injunctive or other equitable relief, any dispute or controversy of any kind arising out of or related to this Agreement, the Executive's employment with the Company, the separation of the Executive from that employment and from his positions as an officer and/or director of the Company or any subsidiary or affiliate, or any claims for benefits, will be resolved exclusively by final and binding arbitration using a one-member arbitration panel selected by mutual agreement, or if the Parties fail to agree on an arbitrator, then in accordance with the Commercial Arbitration Rules of the American Arbitration Association currently in effect, provided, however, that the arbitrator will be limited to awarding the award requested by the Executive or the Company and shall not determine an alternative or compromise remedy. The only claims not covered by this paragraph are any non-waivable claims for benefits under workers' compensation or unemployment insurance laws, which will be resolved under those laws. Any arbitration pursuant to this paragraph will take place in San Francisco, California. The Parties may be represented by legal counsel at the arbitration but must bear their own fees for such representation in the first instance, subject to a claim for subsequent reimbursement under paragraph 17. The Parties will equally share the costs of the arbitration, including the arbitrator's fees, administrative costs and filing fees, unless otherwise prohibited by law. To the extent properly split, said arbitration costs will be subject to a claim for subsequent reimbursement under paragraph 17. The Parties agree that the arbitrator will have the power to decide any motions brought by any party to the arbitration, including discovery motions, motions for summary judgment and/or adjudication and motions to dismiss and demurrers, prior to any arbitration hearing. The arbitrator will issue a written decision on the merits. The Parties specifically waive any right to a jury trial on any dispute or controversy covered by this paragraph. Judgment may be entered on the arbitrator's award in any court of competent jurisdiction. Subject to the arbitration provisions of this paragraph, the sole jurisdiction and venue for any action for injunctive or declaratory relief related to the subject matter of this Agreement will be the California state and federal courts in the City and County of San Francisco, and both Parties hereby consent to the jurisdiction of such courts for any such action.

15. **Governing law.** This Agreement will be governed by and construed under the laws of the United States and, to the extent not preempted by such laws, by the laws of the State of California, without regard to their conflicts of laws provisions.

16. **No waiver.** The failure of either Party to exercise or enforce, at any time, or for any period of time, any of the provisions of this Agreement will not be construed as a waiver of that provision, or any portion of that provision, and will in no way affect that party's right to exercise or enforce such provisions. No waiver or default of any provision of this Agreement will be deemed to be a waiver of any succeeding breach of the same or any other provisions of this Agreement.

17. **Attorney's Fees and Costs.** The prevailing party in any dispute or controversy

over the terms of this Agreement will be entitled to recover, in addition to any other available remedies specified in this Agreement, (i) such party's reasonable attorneys' fees, except as otherwise set forth herein and (ii) such party's all other litigation expenses and costs incurred in litigation or arbitration, including any arbitrator, administrative or filing fees except to the extent that the recovery of such costs is prohibited or limited by law.

18. **Acceptance of Agreement.**

a. The Executive was provided up to 21 days to consider and accept the terms of this Agreement and was advised to consult with an attorney about the Agreement before signing it. After signing the Agreement, the Executive will have an additional seven (7) days in which to revoke in writing acceptance of this Agreement. To revoke, the Executive will submit a signed statement to that effect to PG&E Corporation's Chief Legal Officer before the close of business on the seventh day. If the Executive does not submit a timely revocation, the Effective Date of this Agreement will be the eighth day after he has signed it.

b. The Executive acknowledges reading and understanding the contents of this Agreement, being afforded the opportunity to review carefully this Agreement with an attorney of his choice, not relying on any oral or written representation not contained in this Agreement, signing this Agreement knowingly and voluntarily, and, after the Effective Date of this Agreement, being bound by all of its provisions.

Dated: July 8, 2008 .

PACIFIC GAS AND ELECTRIC COMPANY

By: JOHN R. SIMON
JOHN R. SIMON

Dated: July 8, 2008
3:00pm

William T. Morrow

WILLIAM T. MORROW

EXHIBIT A

EMPLOYMENT TERMINATION CERTIFICATE

I entered into a **SEPARATION AGREEMENT** (☐ *Separation Agreement* ☐) with Pacific Gas & Electric Company (☐ *Company* ☐) dated July , 2008 (☐ *Effective Date* ☐). I hereby acknowledge that:

(1) A blank copy of this Employment Termination Certificate was attached as Exhibit A to the Separation Agreement when the Company gave it to me for review. I have been given sufficient and reasonable time to consider signing this Certificate. I have discussed the Separation Agreement and this Certificate with an attorney before executing either document.

(2) The benefits payable under paragraph 2(a)-(c) of the Separation Agreement are only payable to me if I sign this Certificate after the Resignation Date (as defined in the Separation Agreement).

(3) I executed the Separation Agreement prior to my last day of employment. In exchange for the remaining benefits provided for in paragraph 2(a)-(c) of the Separation Agreement, I hereby agree that this Certificate will be a part of my Separation Agreement such that the release of claims and the covenants that I provided under paragraph 5 of the Separation Agreement will, by my signature below, extend to and cover any other claims that arose after the Effective Date, up to and including the Resignation Date and the date this Certificate is signed, provided, however, by signing the Employment Termination Certificate I am not releasing any claim I have to receive any and all benefits otherwise due to me under the terms of the Separation Agreement, or otherwise required by law.

(4) Nothing in this Certificate alters, diminishes, or mitigates the scope and breadth of the releases and covenants that I previously provided to the Company under the Separation Agreement, which shall remain in full force and effect regardless of whether I sign this Certificate.

(5) By signing below, I hereby extend the release of claims and the covenants that I provided to the Company and other released parties under the Separation Agreement to cover any other claims (as more fully described in paragraph 5 of the Separation Agreement) that arose or may have arisen at any time after the Effective Date, up to and including the Resignation Date and the date this Certificate is signed. I knowingly and voluntarily waive any and all rights or benefits which I may have had, may now have or in the future may have under the terms of Section 1542 of the California Civil Code, which provides as follows:

**A GENERAL RELEASE DOES NOT EXTEND TO CLAIMS WHICH THE CREDITOR DOES NOT
KNOW OR SUSPECT TO EXIST IN HIS OR HER FAVOR AT THE TIME OF EXECUTING THE
RELEASE WHICH, IF KNOWN BY HIM OR HER MUST**

HAVE MATERIALLY AFFECTED HIS OR HER SETTLEMENT WITH THE DEBTOR.

I understand that section 1542 gives me the right not to release existing claims of which I am not now aware, but I expressly and voluntarily choose to waive my rights under California Civil Code Section 1542, as well as under any other federal or state statute or common law principles of similar effect.

I UNDERSTAND THAT I HAVE A RIGHT TO CONSULT WITH AN ATTORNEY OF MY OWN CHOOSING AND TO HAVE THE TERMS OF THIS CERTIFICATE FULLY EXPLAINED TO ME PRIOR TO SIGNING, AND THAT I AM GIVING UP ANY LEGAL CLAIMS I HAVE AGAINST THE PARTIES RELEASED IN THE SEPARATION AGREEMENT BY SIGNING THIS CERTIFICATE. I AM SIGNING THIS CERTIFICATE KNOWINGLY, WILLINGLY AND VOLUNTARILY IN EXCHANGE FOR THE BENEFITS DESCRIBED IN THE SEPARATION AGREEMENT.

William T. Morrow

Date: _____

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

(in millions, except per share amounts)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Net income	\$ 304	\$ 278	\$ 821	\$ 803
Less: distributed earnings to common shareholders	140	127	419	379
Undistributed earnings	<u>\$ 164</u>	<u>\$ 151</u>	<u>\$ 402</u>	<u>\$ 424</u>
Common shareholders earnings				
<i>Basic</i>				
Distributed earnings to common shareholders	\$ 140	\$ 127	\$ 419	\$ 379
Undistributed earnings allocated to common shareholders	156	143	382	402
Total common shareholders earnings, basic	<u>\$ 296</u>	<u>\$ 270</u>	<u>\$ 801</u>	<u>\$ 781</u>
<i>Diluted</i>				
Distributed earnings to common shareholders	\$ 140	\$ 127	\$ 419	\$ 379
Undistributed earnings allocated to common shareholders	156	143	382	402
Total common shareholders earnings, diluted	<u>\$ 296</u>	<u>\$ 270</u>	<u>\$ 801</u>	<u>\$ 781</u>
Weighted average common shares outstanding, basic	357	352	356	350
9.50% Convertible Subordinated Notes	19	19	19	19
Weighted average common shares outstanding and participating securities, basic	<u>376</u>	<u>371</u>	<u>375</u>	<u>369</u>
Weighted average common shares outstanding, basic	357	352	356	350
Employee share-based compensation	1	1	1	2
Weighted average common shares outstanding, diluted	358	353	357	352
9.50% Convertible Subordinated Notes	19	19	19	19
Weighted average common shares outstanding and participating securities, diluted	<u>377</u>	<u>372</u>	<u>376</u>	<u>371</u>
Net earnings per common share, basic				
Distributed earnings, basic ⁽¹⁾	\$ 0.39	\$ 0.36	\$ 1.18	\$ 1.08
Undistributed earnings, basic	0.44	0.41	1.07	1.15
Total	<u>\$ 0.83</u>	<u>\$ 0.77</u>	<u>\$ 2.25</u>	<u>\$ 2.23</u>
Net earnings per common share, diluted				
Distributed earnings, diluted	\$ 0.39	\$ 0.36	\$ 1.17	\$ 1.08
Undistributed earnings, diluted	0.44	0.41	1.07	1.14
Total	<u>\$ 0.83</u>	<u>\$ 0.77</u>	<u>\$ 2.24</u>	<u>\$ 2.22</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 September 30, <u>2008</u>	Nine Months Ended September 30, <u>2008</u>	Year Ended December 31,				
			<u>2007</u>	<u>2006</u>	<u>2005</u>	<u>2004</u>	<u>2003</u>
Earnings:							
Net income	\$ 321	\$ 870	\$ 1,024	\$ 985	\$ 934	\$ 3,982	\$ 923
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	167	421	571	602	574	2,561	528
Net fixed charges	209	650	889	801	589	671	964
Total Earnings	<u>\$ 697</u>	<u>\$ 1,941</u>	<u>\$ 2,484</u>	<u>\$ 2,388</u>	<u>\$ 2,097</u>	<u>\$ 7,214</u>	<u>\$ 2,415</u>
Fixed Charges:							
Interest on short-term borrowings and long-term debt, net	\$ 194	\$ 605	\$ 834	\$ 770	\$ 573	\$ 682	\$ 947
Interest on capital leases	5	16	23	11	1	1	1
AFUDC debt	10	29	32	20	15	(12)	16
Earnings required to cover the preferred stock dividend and preferred security distribution requirements of majority owned trust	-	-	-	-	-	-	-
Total Fixed Charges	<u>\$ 209</u>	<u>\$ 650</u>	<u>\$ 889</u>	<u>\$ 801</u>	<u>\$ 589</u>	<u>\$ 671</u>	<u>\$ 964</u>
Ratios of Earnings to Fixed Charges	<u>3.33</u>	<u>2.99</u>	<u>2.79</u>	<u>2.98</u>	<u>3.56</u>	<u>10.75</u>	<u>2.51</u>

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 dividend requirements and preferred security distribution requirements of majority-owned trust. Fixed charges exclude interest on FASB Interpretation No. 48 (Accounting for Uncertainty in Income Taxes) tax liabilities.

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

	Three Months Ended September 30, <u>2008</u>	Six Months Ended September 30, <u>2008</u>	<u>2007</u>	Year Ended December 31,				<u>2003</u>
	<u>2006</u>	<u>2005</u>	<u>2004</u>					
Earnings:								
Net income	\$ 321	\$ 870	\$ 1,024	\$ 985	\$ 934	\$ 3,982	\$ 923	
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	167	421	571	602	574	2,561	528	
Net fixed charges	209	650	889	801	589	671	964	
Total Earnings	<u>\$ 697</u>	<u>\$ 1,941</u>	<u>\$ 2,484</u>	<u>\$ 2,388</u>	<u>\$ 2,097</u>	<u>\$ 7,214</u>	<u>\$ 2,415</u>	
Fixed Charges:								
Interest on short- term borrowings and long-term debt, net	\$ 194	\$ 605	\$ 834	\$ 770	\$ 573	\$ 682	\$ 947	
Interest on capital leases	5	16	23	11	1	1	1	
AFUDC debt	10	29	32	20	15	(12)	16	
Earnings required to cover the preferred stock dividend and preferred security distribution requirements of majority owned trust	-	-	-	-	-	-	-	
Total Fixed Charges	<u>209</u>	<u>650</u>	<u>889</u>	<u>801</u>	<u>589</u>	<u>671</u>	<u>964</u>	
Preferred Stock Dividends:								
Tax deductible dividends	3	9	9	12	12	9	9	
Pre-tax earnings required to cover non-tax deductible preferred stock dividend requirements	1	2	8	3	13	34	27	
Total Preferred Stock Dividends	<u>4</u>	<u>11</u>	<u>17</u>	<u>15</u>	<u>25</u>	<u>43</u>	<u>36</u>	
Total Combined Fixed Charges and Preferred Stock Dividends								
	\$ 213	\$ 661	\$ 906	\$ 816	\$ 614	\$ 714	\$ 1,000	

**Ratios of Earnings to
Combined Fixed**

**Charges and
Preferred Stock
Dividends**

<u>3.27</u>	<u>2.94</u>	<u>2.74</u>	<u>2.93</u>	<u>3.42</u>	<u>10.10</u>	<u>2.42</u>
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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 the preferred stock dividend requirements and preferred security distribution requirements of majority-owned trust. "Preferred stock dividends" represent tax deductible dividends and pre-tax earnings that are required to pay the dividends on outstanding preferred securities. Fixed charges exclude interest on FASB Interpretation No. 48 (Accounting for Uncertainty in Income Taxes) tax liabilities.

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 September 30, 2008 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: November 6, 2008

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 September 30, 2008 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: November 6, 2008

CHRISTOPHER P. JOHNS
Christopher P. Johns
Senior Vice President, Chief Financial Officer and Treasurer

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 September 30, 2008 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: November 6, 2008

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 September 30, 2008 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: November 6, 2008

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 September 30, 2008 ("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

November 6, 2008

**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 September 30, 2008 ("Form 10-Q"), I, Christopher P. Johns, Senior Vice President, Chief Financial Officer and Treasurer 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 and Treasurer

November 6, 2008

**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 September 30, 2008 ("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

November 6, 2008

**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 September 30, 2008 ("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

November 6, 2008