

PG&E CORP

FORM 10-Q (Quarterly Report)

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

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, 2006

OR

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

For the transition period from _____ to _____

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

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

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

Address of principal executive offices, including zip code

Pacific Gas and Electric Company
(415) 973-7000

PG&E Corporation
(415) 267-7000

Registrant's telephone number, including area code

Indicate by check mark whether the registrants (1) have 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, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

PG&E Corporation: ☒ Large accelerated filer ☐ Accelerated Filer ☐ Non-accelerated filer

Pacific Gas and Electric Company: ☐ Large accelerated filer ☐ Accelerated Filer ☒ Non-accelerated filer

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 November 6, 2006:

PG&E Corporation	348,810,184 shares (excluding 24,665,500 shares held by a wholly owned subsidiary)
Pacific Gas and Electric Company	Wholly owned by PG&E Corporation

**PG&E CORPORATION AND
PACIFIC GAS AND ELECTRIC COMPANY,
FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2006
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PART I. FINANCIAL INFORMATION
ITEM 1: 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,	
	2006	2005	2006	2005
Operating Revenues				
Electric	\$ 2,470	\$ 2,107	\$ 6,547	\$ 5,546
Natural gas	698	697	2,786	2,424
Total operating revenues	3,168	2,804	9,333	7,970
Operating Expenses				
Cost of electricity	884	742	2,195	1,626
Cost of natural gas	298	326	1,539	1,293
Operating and maintenance	795	740	2,639	2,177
Depreciation, amortization and decommissioning	456	481	1,291	1,320
Total operating expenses	2,433	2,289	7,664	6,416
Operating Income	735	515	1,669	1,554
Interest income	40	22	104	60
Interest expense	(152)	(145)	(470)	(438)
Other income (expense), net	(22)	(14)	6	(16)
Income Before Income Taxes	601	378	1,309	1,160
Income tax provision	208	139	470	436
Income From Continuing Operations	393	239	839	724
Discontinued Operations	-	13	-	13
Net Income	\$ 393	\$ 252	\$ 839	\$ 737
Weighted Average Common Shares Outstanding, Basic	347	372	345	376
Earnings Per Common Share from Continuing Operations, Basic	\$ 1.09	\$ 0.63	\$ 2.36	\$ 1.88
Net Earnings Per Common Share, Basic	\$ 1.09	\$ 0.66	\$ 2.36	\$ 1.91
Earnings Per Common Share from Continuing Operations, Diluted	\$ 1.09	\$ 0.62	\$ 2.33	\$ 1.86
Net Earnings Per Common Share, Diluted	\$ 1.09	\$ 0.65	\$ 2.33	\$ 1.89
Dividends Declared Per Common Share	\$ 0.33	\$ 0.30	\$ 0.99	\$ 0.90

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions)	Balance At	
	September 30, 2006 (Unaudited)	December 31, 2005
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 422	\$ 713
Restricted cash	1,445	1,546
Accounts receivable:		
Customers (net of allowance for doubtful accounts of \$47 million in 2006 and \$77 million in 2005)	2,183	2,422
Regulatory balancing accounts	521	727
Inventories:		
Gas stored underground and fuel oil	235	231
Materials and supplies	137	133
Income taxes receivable	-	21
Prepaid expenses and other	753	187
Total current assets	5,696	5,980
Property, Plant and Equipment		
Electric	24,022	22,482
Gas	9,013	8,794
Construction work in progress	749	738
Other	16	16
Total property, plant and equipment	33,800	32,030
Accumulated depreciation	(12,439)	(12,075)
Net property, plant and equipment	21,361	19,955
Other Noncurrent Assets		
Regulatory assets	5,248	5,578
Nuclear decommissioning funds	1,817	1,719
Other	707	842
Total other noncurrent assets	7,772	8,139
TOTAL ASSETS	\$ 34,829	\$ 34,074

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)

	Balance At	
	September 30, 2006 (Unaudited)	December 31, 2005
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	\$ 281	\$ 260
Long-term debt, classified as current	281	2
Rate reduction bonds, classified as current	290	290
Energy recovery bonds, classified as current	343	316
Accounts payable:		
Trade creditors	720	980
Disputed claims and customer refunds	1,714	1,733
Regulatory balancing accounts	1,099	840
Other	455	441
Interest payable	481	473
Income taxes payable	192	-
Deferred income taxes	126	181
Other	1,572	1,416
Total current liabilities	7,554	6,932
Noncurrent Liabilities		
Long-term debt	6,696	6,976
Rate reduction bonds	76	290
Energy recovery bonds	2,025	2,276
Regulatory liabilities	3,601	3,506
Asset retirement obligations	1,654	1,587
Deferred income taxes	2,980	3,092
Deferred tax credits	107	112
Other	2,124	1,833
Total noncurrent liabilities	19,263	19,672
Commitments and Contingencies (Notes 2, 4, 5, 10 and 11)		
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 371,976,417 common and 1,375,576 restricted shares in 2006 and 366,868,512 common and 1,399,990 restricted shares in 2005	5,853	5,827
Common stock held by subsidiary, at cost, 24,665,500 shares	(718)	(718)
Unearned compensation	-	(22)
Reinvested earnings	2,633	2,139
Accumulated other comprehensive loss	(8)	(8)
Total common shareholders' equity	7,760	7,218
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	\$ 34,829	\$ 34,074

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,	
	2006	2005
Cash Flows From Operating Activities		
Net income	\$ 839	\$ 737
Discontinued operations	-	(13)
Net income from continuing operations	839	724
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, decommissioning and allowance for equity funds used during construction	1,343	1,295
Deferred income taxes and tax credits, net	(172)	(658)
Other deferred charges and noncurrent liabilities	(37)	(133)
Gain on sale of assets	(15)	-
Net effect of changes in operating assets and liabilities:		
Accounts receivable	239	58
Inventories	(8)	(97)
Accounts payable	(175)	(80)
Accrued taxes	212	14
Regulatory balancing accounts, net	404	940
Other current assets	(71)	(203)
Other current liabilities	(325)	145
Other	6	112
Net cash provided by operating activities	2,240	2,117
Cash Flows From Investing Activities		
Capital expenditures	(1,729)	(1,318)
Net proceeds from sale of assets	11	19
Decrease in restricted cash	58	453
Proceeds from nuclear decommissioning trust sales	942	2,428
Purchases of nuclear decommissioning trust investments	(1,040)	(2,492)
Other	-	67
Net cash used in investing activities	(1,758)	(843)
Cash Flows From Financing Activities		
Borrowings under accounts receivable facility	50	-
Repayments under working capital facility and accounts receivable facility	(310)	(300)
Borrowings under commercial paper facility, net	281	-
Proceeds from issuance of long-term debt, net of issuance costs of \$3 million in 2005	-	451
Proceeds from issuance of energy recovery bonds, net of issuance costs of \$14 million in 2005	-	1,874
Long-term debt matured, redeemed or repurchased	(1)	(1,556)
Rate reduction bonds matured	(214)	(214)
Energy recovery bonds matured	(224)	(77)
Preferred stock with mandatory redemption provisions redeemed	-	(122)
Preferred stock without mandatory redemption provisions redeemed	-	(36)
Common stock issued	108	231
Common stock repurchased	(114)	(1,087)
Common stock dividends paid	(342)	(223)
Other	(7)	46
Net cash used in financing activities	(773)	(1,013)
Net change in cash and cash equivalents	(291)	261

Cash and cash equivalents at January 1

713

972

Cash and cash equivalents at September 30	\$	422	\$	1,233
Supplemental disclosures of cash flow information				
Cash paid for:				
Interest (net of amounts capitalized)	\$	450	\$	373
Income taxes paid, net		428		1,051
Supplemental disclosures of noncash investing and financing activities				
Common stock dividends declared but not yet paid	\$	116	\$	111
Capital lease obligation		408		-

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,	
	2006	2005	2006	2005
Operating Revenues				
Electric	\$ 2,470	\$ 2,107	\$ 6,547	\$ 5,546
Natural gas	698	697	2,786	2,424
Total operating revenues	3,168	2,804	9,333	7,970
Operating Expenses				
Cost of electricity	884	742	2,195	1,626
Cost of natural gas	298	326	1,539	1,293
Operating and maintenance	793	738	2,637	2,179
Depreciation, amortization and decommissioning	456	481	1,290	1,320
Total operating expenses	2,431	2,287	7,661	6,418
Operating Income	737	517	1,672	1,552
Interest income	36	20	94	59
Interest expense	(144)	(138)	(447)	(416)
Other income (expense), net	(15)	(3)	16	9
Income Before Income Taxes	614	396	1,335	1,204
Income tax provision	236	148	509	457
Net Income	378	248	826	747
Preferred stock dividend requirement	3	4	10	12
Income Available for Common Stock	\$ 375	\$ 244	\$ 816	\$ 735

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions)	Balance At	
	September 30, 2006 (Unaudited)	December 31, 2005
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 68	\$ 463
Restricted cash	1,445	1,546
Accounts receivable:		
Customers (net of allowance for doubtful accounts of \$47 million in 2006 and \$77 million in 2005)	2,183	2,422
Related parties	24	3
Regulatory balancing accounts	521	727
Inventories:		
Gas stored underground and fuel oil	235	231
Materials and supplies	137	133
Income taxes receivable	-	48
Prepaid expenses and other	753	183
Total current assets	5,366	5,756
Property, Plant and Equipment		
Electric	24,022	22,482
Gas	9,013	8,794
Construction work in progress	749	738
Total property, plant and equipment	33,784	32,014
Accumulated depreciation	(12,424)	(12,061)
Net property, plant and equipment	21,360	19,953
Other Noncurrent Assets		
Regulatory assets	5,248	5,578
Nuclear decommissioning funds	1,817	1,719
Related parties receivable	-	23
Other	612	754
Total other noncurrent assets	7,677	8,074
TOTAL ASSETS	\$ 34,403	\$ 33,783

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)

	Balance At	
	September 30,	December 31,
	2006	2005
	(Unaudited)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	\$ 281	\$ 260
Long-term debt, classified as current	1	2
Rate reduction bonds, classified as current	290	290
Energy recovery bonds, classified as current	343	316
Accounts payable:		
Trade creditors	720	980
Disputed claims and customer refunds	1,714	1,733
Related parties	38	37
Regulatory balancing accounts	1,099	840
Other	441	423
Interest payable	474	460
Income taxes payable	65	-
Deferred income taxes	96	161
Other	1,419	1,255
Total current liabilities	6,981	6,757
Noncurrent Liabilities		
Long-term debt	6,696	6,696
Rate reduction bonds	76	290
Energy recovery bonds	2,025	2,276
Regulatory liabilities	3,601	3,506
Asset retirement obligations	1,654	1,587
Deferred income taxes	3,116	3,218
Deferred tax credits	107	112
Other	1,984	1,691
Total noncurrent liabilities	19,259	19,376
Commitments and Contingencies (Notes 2, 4, 5, 10 and 11)		
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 279,624,823 shares	1,398	1,398
Common stock held by subsidiary, at cost, 19,481,213 shares	(475)	(475)
Additional paid-in capital	1,818	1,776
Reinvested earnings	5,173	4,702
Accumulated other comprehensive loss	(9)	(9)
Total shareholders' equity	8,163	7,650
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	\$ 34,403	\$ 33,783

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,	
	2006	2005
Cash Flows From Operating Activities		
Net income	\$ 826	\$ 747
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, decommissioning and allowance for equity funds used during construction	1,342	1,294
Deferred income taxes and tax credits, net	(172)	(638)
Other deferred charges and noncurrent liabilities	(65)	(136)
Gain on sale of assets	(15)	-
Net effect of changes in operating assets and liabilities:		
Accounts receivable	239	58
Inventories	(8)	(97)
Accounts payable	(176)	(83)
Accrued taxes	113	77
Regulatory balancing accounts, net	404	940
Other current assets	(71)	(196)
Other current liabilities	(301)	141
Other	(5)	20
Net cash provided by operating activities	2,111	2,127
Cash Flows From Investing Activities		
Capital expenditures	(1,729)	(1,318)
Net proceeds from sale of assets	11	19
Decrease in restricted cash	58	453
Proceeds from nuclear decommissioning trust sales	942	2,428
Purchases of nuclear decommissioning trust investments	(1,040)	(2,492)
Other	-	67
Net cash used in investing activities	(1,758)	(843)
Cash Flows From Financing Activities		
Borrowings under accounts receivable facility	50	-
Repayments under working capital facility and accounts receivable facility	(310)	(300)
Borrowings under commercial paper facility, net	281	-
Proceeds from issuance of long-term debt, net of issuance costs of \$3 million in 2005	-	451
Proceeds from issuance of energy recovery bonds, net of issuance costs of \$14 million in 2005	-	1,874
Long-term debt matured, redeemed or repurchased	(1)	(1,554)
Rate reduction bonds matured	(214)	(214)
Energy recovery bonds matured	(224)	(77)
Common stock dividends paid	(345)	(330)
Preferred stock dividends paid	(10)	(12)
Preferred stock with mandatory redemption provisions redeemed	-	(122)
Preferred stock without mandatory redemption provisions redeemed	-	(36)
Common stock repurchased	-	(960)
Other	25	69
Net cash used in financing activities	(748)	(1,211)
Net change in cash and cash equivalents	(395)	73
Cash and cash equivalents at January 1	463	783

Cash and cash equivalents at September 30	\$	68	\$	856
Supplemental disclosures of cash flow information				
Cash paid for:				
Interest (net of amounts capitalized)	\$	423	\$	360
Income taxes paid, net		562		1,047
Supplemental disclosures of noncash investing and financing activities				
Capital lease obligation	\$	408	\$	-

See accompanying Notes to the Condensed Consolidated Financial Statements.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1: ORGANIZATION AND BASIS OF PRESENTATION

PG&E Corporation is a holding company whose primary purpose is to hold interests in energy-based businesses. The company conducts its business principally through Pacific Gas and Electric Company, or the Utility, a public utility operating in northern and central California. The Utility engages primarily 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, or CPUC, and the Federal Energy Regulatory Commission, or FERC.

This Quarterly Report on Form 10-Q is a combined report of PG&E Corporation and the Utility. Therefore, the Notes to the unaudited 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 its accounts and those of its wholly owned and controlled subsidiaries, and a variable interest entity which the Utility is required to consolidate under applicable accounting standards. All intercompany transactions have been eliminated from the Condensed Consolidated Financial Statements.

The accompanying interim unaudited Condensed Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America, or 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, or SEC, and do not contain all of the information and footnotes required by GAAP and the SEC for annual financial statements. The information at December 31, 2005 in both PG&E Corporation's and the Utility's Condensed Consolidated Balance Sheets included in this quarterly report was derived from the audited Consolidated Balance Sheets incorporated by reference into their combined Annual Report on Form 10-K for the year ended December 31, 2005. (PG&E Corporation's and the Utility's combined Annual Report on Form 10-K for the year ended December 31, 2005, together with the information incorporated by reference into such report, is referred to in this quarterly report as the "2005 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 in the Notes to the Consolidated Financial Statements in the 2005 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 and 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 (including delayed billings), disputed claims, asset retirement obligations, allowance for doubtful accounts receivable, provisions for losses that are deemed probable from environmental remediation liabilities, pension and other employee benefit plan liabilities, mark-to-market accounting, income tax related liabilities, litigation, and the Utility's review for impairment of long-lived assets and certain identifiable intangibles to be held and used whenever events or changes in circumstances indicate that the carrying amount of its assets might not be recoverable. A change in management's estimates or assumptions could have a material impact on PG&E Corporation's and the Utility's financial condition and results of operations during the period in which such change occurred. 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 could differ materially from these estimates and assumptions. PG&E Corporation's and the Utility's Condensed Consolidated Financial Statements reflect all adjustments that management believes are necessary for the fair presentation of their financial condition and results of operations for the periods presented. The results of operations for interim periods are not necessarily indicative of the results of operations for the full year.

As discussed below in Note 10, the U.S. Bankruptcy Court for the Northern District of California, or Bankruptcy Court, which oversaw the Utility's proceeding under Chapter 11 of the U.S. Bankruptcy Code, or Chapter 11, retains jurisdiction, among other things, to resolve the remaining disputed claims that were made in the Utility's Chapter 11 proceeding.

This quarterly report should be read in conjunction with PG&E Corporation's and the Utility's Consolidated Financial Statements and Notes to the Consolidated Financial Statements in the 2005 Annual Report.

NOTE 2: NEW AND SIGNIFICANT ACCOUNTING POLICIES

Variable Interest Entities

In April 2006, the Financial Accounting Standards Board, or FASB, issued Staff Position No. FIN 46R-6, "Determining the Variability to Be Considered in Applying FASB Interpretation No. 46R," or FSP FIN 46R-6. FSP FIN 46R-6 specifies how a company should determine variability in applying the accounting standard for consolidation of variable interest entities. The pronouncement states that such variability shall be determined based on an analysis of the design of the entity, including the nature of the risks in the entity, the purpose for which the entity was created, and the variability that the entity is designed to create and pass along to its interest holders. PG&E Corporation and the Utility adopted FSP FIN 46R-6 on July 1, 2006. The adoption of FSP FIN 46R-6 did not have a material impact on the Condensed Consolidated Financial Statements of PG&E Corporation or the Utility for the three and nine months ended September 30, 2006.

Share-Based Payment

On January 1, 2006, PG&E Corporation and the Utility adopted the provisions of Statement of Financial Accounting, or SFAS, No. 123R, "Share-Based Payment," or 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 shares that are expected to vest. Prior to January 1, 2006, PG&E Corporation and the Utility accounted for share-based payments, such as stock options, restricted stock and other share-based incentive awards, under the recognition and measurement provisions of Accounting Principles Board, or APB, Opinion No. 25, "Accounting for Stock Issued to Employees," or Opinion 25, as permitted by SFAS No. 123, "Accounting for Stock-Based Compensation," or SFAS No. 123. Under the provisions of Opinion 25, compensation cost for stock options was not recognized for periods prior to January 1, 2006, as all options granted under those plans had an exercise price equal to the market value of the underlying common stock on the date of grant.

For the nine months ended September 30, 2006, PG&E Corporation's and the Utility's operating income, income before income taxes, net income, and basic and diluted earnings per share are lower than if they had continued to account for share-based payments under Opinion 25. The following table provides a summary of the decrease of the items listed above as a result of SFAS No. 123R adoption:

(in millions except per share amounts)	PG&E		Utility	
	Corporation			
	Nine Months		Nine Months	
	Ended		Ended	
	September 30,		September 30,	
	2006		2006	
Operating Income	\$	(15)	\$	(11)
Income Before Income Taxes		(15)		(11)
Net Income		(9)		(7)
Earnings Per Common Share, Basic	\$	(0.02)		
Earnings Per Common Share, Diluted	\$	(0.03)		

For the three months ended September 30, 2006, the impact on the above items was immaterial. The impact on net income for the nine months ended September 30, 2006 is primarily attributed to the prospective application of accounting for share-based payment awards with terms that accelerate vesting on retirement and expense recognition of previously unvested stock options.

Prior to the adoption of SFAS No. 123R, PG&E Corporation and the Utility expensed share-based awards over the stated vesting period regardless of terms that accelerate vesting upon retirement. Subsequent to the adoption of SFAS No. 123R, compensation expense for all awards will be recognized over the shorter of the stated vesting period or the requisite service period. If awards granted prior to adopting SFAS No. 123R were expensed over the requisite service period instead of the stated vesting period, there would have been an immaterial impact on the Condensed Consolidated Financial Statements of PG&E Corporation and the Utility for the three and nine months ended September 30, 2006.

Prior to the adoption of SFAS No. 123R, PG&E Corporation and the Utility presented all tax benefits from share-based payment awards as operating cash flows in the Statement of Cash Flows. SFAS No. 123R requires the cash flows from the tax benefits resulting from tax deductions in excess of the compensation cost recognized for those awards (excess tax



benefits) to be classified as financing cash flows. PG&E Corporation's and the Utility's excess tax benefit of \$38 million and \$42 million, respectively, would have been classified as an operating cash inflow if PG&E Corporation and the Utility had not adopted SFAS No. 123R (see Note 8 below for further discussion of share-based compensation).

The following table illustrates the effect on PG&E Corporation's net income and earnings per common share, or EPS, for the three and nine months ended September 30, 2005 if PG&E Corporation had applied the fair value recognition provisions of SFAS No. 123 to outstanding options.

(in millions, except per share amounts)	Three Months Ended September 30,	Nine Months Ended September 30,
	2005	2005
Net income:		
As reported	\$ 252	\$ 737
Deduct: Incremental share-based employee compensation expense determined under the fair value based method for all awards, net of related tax effects	3	10
Pro forma	<u>\$ 249</u>	<u>\$ 727</u>
Basic earnings per common share:		
As reported	\$ 0.66	\$ 1.91
Pro forma	0.65	1.88
Diluted earnings per common share:		
As reported	\$ 0.65	\$ 1.89
Pro forma	0.64	1.86

The following table illustrates the effect on the Utility's net income for the three and nine months ended September 30, 2005 if the fair value recognition provisions of SFAS No. 123 had been applied to outstanding options.

(in millions)	Three Months Ended September 30,	Nine Months Ended September 30,
	2005	2005
Income available for common stock:		
As reported	\$ 244	\$ 735
Deduct: Incremental share-based employee compensation expense determined under the fair value based method for all awards, net of related tax effects	2	6
Pro forma	<u>\$ 242</u>	<u>\$ 729</u>

Accounting Changes and Error Corrections

On January 1, 2006, PG&E Corporation and the Utility adopted SFAS No. 154, "Accounting Changes and Error Corrections Disclosure," or SFAS No. 154. SFAS No. 154 replaces APB Opinion No. 20, "Accounting Changes," and SFAS No. 3, "Reporting Accounting Changes in Interim Financial Statements." SFAS No. 154 requires retrospective application to prior periods' financial statements of changes in accounting principle unless it is impracticable. SFAS No. 154 applies to all voluntary changes in accounting principle. It also applies to changes required by a new accounting pronouncement unless the new pronouncement includes contrary explicit transition provisions. The adoption of SFAS No. 154 did not have an impact on the Condensed Consolidated Financial Statements of PG&E Corporation or the Utility for the three and nine months ended September 30, 2006.

Other-Than-Temporary Impairment

In November 2005, the FASB issued Staff Position Nos. FAS 115-1 and 124-1, "The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments," or FSP 115-1 and 124-1, to provide guidance in determining when an investment is impaired, whether that impairment is other-than-temporary, and the measurement of an impairment loss. PG&E Corporation and the Utility adopted FSP

115-1 and 124-1 on January 1, 2006. The adoption of FSP 115-1 and 124-1 did not have a material impact on the Condensed Consolidated Financial Statements of PG&E Corporation

or the Utility for the three and nine months ended September 30, 2006.

Changes in Accounting for Certain Derivative Contracts

Derivatives Implementation Group, or DIG, Issue No. B38, "Embedded Derivatives: Evaluation of Net Settlement with respect to the Settlement of a Debt Instrument through Exercise of an Embedded Put Option or Call Option," or DIG B38, and DIG Issue No. B39 "Embedded Derivatives: Application of Paragraph 13(b) to Call Options That Are Exercisable Only by the Debtor," or DIG B39, address the circumstances in which a put or call option embedded in a debt instrument would be bifurcated from the debt instrument and accounted for separately. DIG B38 and DIG B39 were effective beginning in the first quarter of 2006. The adoption of DIG B38 and DIG B39 did not have a material impact on the Condensed Consolidated Financial Statements of PG&E Corporation or the Utility for the three and nine months ended September 30, 2006.

Comprehensive Income

Comprehensive income reports a measure of changes in equity of PG&E Corporation and the Utility that result from transactions and other economic events, other than transactions with shareholders. For the three and nine months ended September 30, 2005, PG&E Corporation's and the Utility's comprehensive income consisted of changes in the effects of the remeasurement of the Utility's defined benefit pension plan. PG&E Corporation and the Utility did not have any comprehensive income activity other than net income for the three and nine months ended September 30, 2006.

(in millions)	PG&E Corporation		Utility	
	2006	2005	2006	2005
Three months ended September 30				
Comprehensive income	<u>\$ 393</u>	<u>\$ 252</u>	<u>\$ 375</u>	<u>\$ 244</u>
Nine months ended September 30				
Net income available for common stock	\$ 839	\$ 737	\$ 816	\$ 735
Minimum pension liability adjustment (net of income tax benefit of \$1 million in 2005)	-	(1)	-	(2)
Comprehensive income	<u>\$ 839</u>	<u>\$ 736</u>	<u>\$ 816</u>	<u>\$ 733</u>

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) reports a measure for accumulated changes in equity of PG&E Corporation and the Utility that result from transactions and other economic events, other than transactions with shareholders. The following table sets forth the changes in each component of accumulated other comprehensive income (loss):

(in millions)	Hedging Transactions in Accordance with SFAS No. 133	Minimum Pension Liability Adjustment	Other	Accumulated Other Comprehensive Income (Loss)
Balance at December 31, 2004	\$ (1)	\$ (4)	\$ 1	\$ (4)
Period change in:				
Minimum pension liability adjustment	-	(1)	-	(1)
Other	1	-	(1)	-
Balance at September 30, 2005	<u>-</u>	<u>(5)</u>	<u>-</u>	<u>(5)</u>
Balance at December 31, 2005	<u>-</u>	<u>(8)</u>	<u>-</u>	<u>(8)</u>
Balance at September 30, 2006	<u>\$ -</u>	<u>\$ (8)</u>	<u>\$ -</u>	<u>\$ (8)</u>

There were no changes in PG&E Corporation's or the Utility's accumulated other comprehensive income (loss) components for the three and nine months ended September 30, 2006.

Pension and Other Postretirement Benefits

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

their employees and retirees (referred to collectively as “other benefits”). PG&E Corporation and the Utility use a December 31 measurement date for all of their plans and use publicly quoted market values and independent pricing services depending on the nature of the assets, as reported by the trustee, to determine the fair value of the plan assets.

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, 2006 and 2005 are as follows:

PG&E Corporation

(in millions)	Pension Benefits		Other Benefits	
	Three Months Ended		Three Months Ended	
	September 30,		September 30,	
	2006	2005	2006	2005
Service cost for benefits earned	\$ 59	\$ 53	\$ 7	\$ 8
Interest cost	128	125	18	18
Expected return on plan assets	(160)	(151)	(23)	(21)
Amortization of transition obligation	-	-	7	6
Amortization of prior service cost	13	14	4	3
Amortization of unrecognized loss	6	7	(1)	-
Net periodic benefit cost	\$ 46	\$ 48	\$ 12	\$ 14

(in millions)	Pension Benefits		Other Benefits	
	Nine Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2006	2005	2006	2005
Service cost for benefits earned	\$ 177	\$ 161	\$ 21	\$ 23
Interest cost	383	374	55	55
Expected return on plan assets	(480)	(451)	(67)	(64)
Amortization of transition obligation	-	-	19	19
Amortization of prior service cost	41	41	11	9
Amortization of unrecognized loss	17	21	(2)	(1)
Net periodic benefit cost	\$ 138	\$ 146	\$ 37	\$ 41

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

Under SFAS No. 71, “Accounting for the Effects of Certain Types of Regulation,” as amended, or SFAS No. 71, regulatory adjustments are recorded in the Condensed Consolidated Statements of Income and Condensed Consolidated Balance Sheets of the Utility to reflect the difference between Utility pension expense or income for accounting purposes and Utility pension expense or income for ratemaking purposes, which is based on a funding approach. The CPUC has authorized the Utility to recover the costs associated with its other benefits for 1993 and beyond. Recovery is based on the lesser of the amounts collected in rates or the annual contribution on a tax-deductible basis to the appropriate trusts. For 2006, only the portion of the pension contribution allocated to the Gas Transmission and Storage business is not recoverable in rates. For the year ended December 31, 2006, the expected reduction in net income as a result of the Utility not being able to recover this portion in rates is approximately \$5 million.

Nuclear Decommissioning Trust Investment Presentation on Statement of Cash Flows

As reported in the 2005 Annual Report, PG&E Corporation and the Utility changed the presentation of the Nuclear Decommissioning Trust investment in their Consolidated Statements of Cash Flows for the year ended December 31, 2005, to present investing cash outflows separately from investing cash inflows. Cash inflows and outflows in the Nuclear Decommissioning Trust investment balances were previously presented as a single line (net) within the investing section of the Statements of Cash Flows. PG&E Corporation and the Utility have presented cash inflows and outflows for the nine months ended September 30, 2006 and 2005 consistent with the 2005 Annual Report presentation. There was no impact to net cash provided by (used in) operating, investing or financing activities as a result of this change in presentation.

ACCOUNTING PRONOUNCEMENTS ISSUED BUT NOT YET ADOPTED

Accounting for Uncertainty in Income Taxes

In July 2006, the FASB issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes," or FIN 48. FIN 48 clarifies the accounting for uncertainty in income taxes. The interpretation prescribes a two-step process in the recognition and measurement of a tax position taken or expected to be taken in a tax return. The first step is to determine if it is more likely than not that a tax position will be sustained upon examination by taxing authorities. If this threshold is met, the second step is to measure the tax position on the balance sheet by using the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. FIN 48 also requires additional disclosures. FIN 48 is effective prospectively for fiscal years beginning after December 15, 2006. PG&E Corporation and the Utility are currently evaluating the impact of this new interpretation.

Fair Value Measurements

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements," or SFAS No. 157. 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. The standard also establishes a framework for measuring fair value and provides for expanded disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. PG&E Corporation and the Utility are currently evaluating the impact of this new accounting pronouncement.

Accounting for Defined Benefit Pensions and Other Postretirement Plans

In September 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans," or SFAS No. 158. SFAS No. 158 will require the funded status of an entity's plans to be recognized on the balance sheet, eliminate the additional minimum liability, and enhance related disclosure requirements. The funded status of a plan will be measured as the difference between the fair value of plan assets and the projected benefit obligation for a pension plan and the accumulated postretirement benefit obligation for other postretirement benefit plans. Additional disclosures are required in the year of application. SFAS No. 158 is effective as of the end of the fiscal year ending after December 15, 2006. PG&E Corporation and the Utility are currently evaluating the impact of this new accounting pronouncement.

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 rates in the future. The regulatory assets are amortized over future periods consistent with the related increase in customer revenue. If costs that a regulated enterprise expects to incur in the future are 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 that 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

The Utility's regulatory assets are comprised of the following:

(in millions)	Balance At	
	September 30, 2006	December 31, 2005
Energy recovery bond regulatory assets	\$ 2,252	\$ 2,509
Utility retained generation regulatory assets	1,038	1,099

Regulatory assets for deferred income tax	577	536
Unamortized loss, net of gain on reacquired debt	301	321
Environmental compliance costs	297	310
Rate reduction bond regulatory assets	248	456
Regulatory assets associated with plan of reorganization	149	163
Post-transition period contract termination costs	123	131
Scheduling coordinator costs	122	-
Other, net	141	53
Total regulatory assets	\$ 5,248	\$ 5,578

On February 10, 2005 and November 9, 2005, PG&E Energy Recovery Funding LLC, or PERF, a limited liability company wholly owned and consolidated by the Utility (but legally separate from the Utility), issued the first and second series, respectively, of energy recovery bonds, or ERBs. The first series was issued for approximately \$1.9 billion to refinance the after-tax balance of the settlement regulatory asset established under the settlement agreement among PG&E Corporation, the Utility, and the CPUC to resolve the Utility's Chapter 11 proceeding, or Settlement Agreement. The second series was issued for approximately \$844 million to pre-fund the Utility's tax liability that will be due as the Utility collects the dedicated rate component, or DRC, related to the first series of ERBs. Upon issuance of the first and second series, the Utility recorded ERB regulatory assets of approximately \$1.9 billion and \$838 million, respectively. For the nine months ended September 30, 2006, the Utility recorded amortization of the ERB regulatory assets of approximately \$257 million. The Utility expects to fully recover the ERB regulatory assets by the end of 2012.

As a result of the Settlement Agreement, the Utility recognized a one-time non-cash gain of \$1.2 billion, pre-tax (\$0.7 billion, after-tax), for the Utility retained generation regulatory assets in the first quarter of 2004. The individual components of these regulatory assets will be amortized over their respective lives, with a weighted average life of approximately 16 years. For the nine months ended September 30, 2006, the Utility recorded amortization of the Utility's retained generation regulatory assets of approximately \$61 million.

The regulatory assets for deferred income tax represent deferred income tax benefits that have already been 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 tax related to regulatory assets over periods ranging from 1 to 40 years.

The regulatory asset related to unamortized loss, net of gain, on reacquired debt represents costs related to debt reacquired or redeemed prior to maturity with associated discount and debt issuance costs. These costs are expected to be recovered over the remaining original amortization period of the reacquired debt over the next 1 to 21 years.

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

The Utility's regulatory asset related to the rate reduction bonds, or RRBs, represents electric industry restructuring costs that the Utility expects to collect over the term of the RRBs. For the nine months ended September 30, 2006, the Utility recorded amortization of the RRB regulatory asset of approximately \$208 million. The Utility expects to fully recover the RRB regulatory asset by the end of 2007.

Regulatory assets associated with the Utility's Chapter 11 plan of reorganization include costs incurred in financing the Utility's exit from Chapter 11 and costs to oversee the environmental enhancement 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 .

The regulatory asset related to post-transition period 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 until the end of September 2014, the power purchase agreement's original termination date.

The regulatory asset related to scheduling coordinator, or SC, costs represents costs that the Utility incurred in its capacity as a scheduling coordinator for its existing wholesale transmission customers beginning in 1998 (see Note 11 below).

Finally, as of September 30, 2006 and December 31, 2005, the regulatory asset "Other, net" includes approximately \$67 million and \$1 million, respectively, related to price risk management, or PRM, contracts entered into by the Utility to procure electricity and natural gas to reduce commodity price risks, which are accounted for as derivatives under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities", or SFAS No. 133. The costs and proceeds of these derivatives are recovered or refunded in regulated rates charged to customers.

In general, the Utility does not earn a return on regulatory assets where the related costs do not accrue interest. Accordingly, the only regulatory assets on which the Utility earns a return are the regulatory assets relating to the Utility's retained generation and unamortized loss, net of gain on reacquired debt.

Regulatory Liabilities

The Utility's regulatory liabilities are comprised of the following:

(in millions)	Balance At	
	September 30, 2006	December 31, 2005
Cost of removal obligation	\$ 2,292	\$ 2,141
Asset retirement costs	578	538
Employee benefit plans	251	195
Public purpose programs	194	154
Rate reduction bonds	110	157
Price risk management	49	213
Other	127	108
Total regulatory liabilities	\$ 3,601	\$ 3,506

The Utility's regulatory liabilities related to the cost of removal obligation represent revenues collected for asset removal costs that the Utility expects to incur in the future. The regulatory liability associated with asset retirement costs represents timing differences between the recognition of asset retirement obligations in accordance with GAAP applicable to non-regulated entities under SFAS No. 143, "Accounting for Asset Retirement Obligations", and FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations - an Interpretation of FASB Statement No. 143", or FIN 47, and the amounts recognized for ratemaking purposes. The Utility's regulatory liabilities related to employee benefit plans represent the cumulative differences between expenses recognized in accordance with GAAP and expenses recognized for ratemaking purposes. The Utility's regulatory liability related to public purpose programs represents revenues designated for public purpose program costs that are expected to be incurred in the future. The Utility's regulatory liability for RRBs represents the deferral of over-collected revenue associated with the RRBs that the Utility expects to return to customers in the future. The Utility's regulatory liability related to PRM represents contracts entered into by the Utility to procure electricity and natural gas to reduce commodity price risks, which are accounted for as derivatives under SFAS No. 133. The costs and proceeds of these derivatives are recovered or refunded in regulated rates charged to customers.

Regulatory Balancing Accounts

The Utility's regulatory balancing accounts are used as a mechanism for the Utility to recover amounts incurred for certain costs, primarily commodity costs. Sales balancing accounts accumulate differences between revenues and the Utility's authorized revenue requirements. Cost balancing accounts accumulate differences between incurred costs and authorized revenue requirements. The Utility also obtained CPUC approval for balancing account treatment of variances between forecasted and actual commodity costs and volumes. This approval results in eliminating the earnings impact from any throughput and revenue variances from adopted forecast levels. 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 that the Utility expects to collect or refund 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 noncurrent regulatory assets and liabilities. The CPUC does not allow the Utility to offset regulatory balancing account assets against balancing account liabilities.

Current Regulatory Balancing Account Assets

(in millions)	Balance At	
	September 30,	December 31,
	2006	2005
Natural gas revenue and cost balancing accounts	\$ 229	\$ 159
Electricity revenue and cost balancing accounts	292	568
Total	\$ 521	\$ 727

Current Regulatory Balancing Account Liabilities

(in millions)	Balance At	
	September 30,	December 31,
	2006	2005
Natural gas revenue and cost balancing accounts	\$ 86	\$ 13
Electricity revenue and cost balancing accounts	1,013	827
Total	\$ 1,099	\$ 840

During the nine months ended September 30, 2006, the under-collection in the Utility's electricity revenue and cost balancing account assets decreased mainly due to increased customer revenue collection from the July 2006 heat storm that resulted in higher electricity usage. The increase in the over-collected position of the Utility's electricity revenue and cost balancing account liabilities is attributable to the Utility's procurement of electricity from hydroelectric resources, which resulted in lower operating costs compared to operating costs associated with procurement from qualifying facilities, or QFs.

The under-collection recorded in the Utility's natural gas revenue and cost balancing account for assets and the over-collection recorded in the Utility's natural gas revenue and cost balancing account for liabilities resulted from set revenue requirements, which exceed actual revenue collection from customers during the spring and summer season when gas usage is lowest for the year.

NOTE 4: DEBT

PG&E Corporation

For details on PG&E Corporation's and the Utility's debt obligations, credit facilities, and short-term borrowings not discussed below, refer to Note 4 in the Notes to the Consolidated Financial Statements in the 2005 Annual Report. Additionally, the Utility is required to recognize capital lease obligations related to certain QF contracts. Refer to Note 11 below for further details.

Convertible Subordinated Notes

PG&E Corporation currently has outstanding \$280 million of 9.50% Convertible Subordinated Notes, or Convertible Subordinated Notes, that are scheduled to mature on June 30, 2010. These Convertible Subordinated Notes may be converted (at the option of the holder) at any time prior to maturity into 18,558,655 shares of common stock of PG&E Corporation, at a conversion price of approximately \$15.09 per share. The conversion price is subject to an adjustment should a significant change occur in the number of PG&E Corporation's outstanding common shares. To date, the conversion price has not required adjustment. In addition, holders of the Convertible Subordinated Notes are entitled to receive "pass-through dividends" determined by multiplying the amount of the cash dividend paid by PG&E Corporation per share of common stock by a number equal to the principal amount of the Convertible Subordinated Notes divided by the conversion price. In connection with each of the common stock dividends paid on January 16, April 15, July 15, and October 15, 2006, PG&E Corporation paid approximately \$6 million of "pass-through dividends" to the holders of Convertible Subordinated Notes. The holders have a one-time right to require PG&E Corporation to repurchase the Convertible Subordinated Notes on June 30, 2007, at a purchase price equal to the principal amount plus accrued and unpaid interest (including liquidated damages and unpaid "pass-through dividends," if any). Accordingly, PG&E Corporation has classified the Convertible

Subordinated Notes in Current Liabilities - Long-term debt, in the accompanying Condensed Consolidated Balance Sheet as of September 30, 2006.

In accordance with SFAS No. 133, the dividend participation rights component is considered to be an embedded derivative instrument and, therefore, must be bifurcated from the Convertible Subordinated Notes and recorded at fair value in PG&E Corporation's Condensed Consolidated Financial Statements. Changes in the fair value are recognized in PG&E Corporation's Condensed Consolidated Statements of Income as a non-operating expense or income (included in Other income (expense), net). At September 30, 2006 and December 31, 2005, the total estimated fair value of the dividend participation rights component, on a pre-tax basis, was approximately \$82 million and \$92 million, respectively, of which \$23 million and \$22 million, respectively, was classified as a current liability (in Current Liabilities - Other) and \$59 million and \$70 million, respectively, was classified as a noncurrent liability (in Noncurrent Liabilities - Other).

Utility

Pollution Control Bonds

The California Pollution Control Financing Authority and the California Infrastructure and Economic Development Bank issued various series of tax-exempt pollution control bonds for the benefit of the Utility. At September 30, 2006, pollution control bonds in the aggregate principal amount of \$1.6 billion were outstanding. Under the pollution control bond loan agreements, the Utility is obligated to pay on the due dates an amount equal to the principal, premium (if any), and interest on these bonds to the trustees for the bonds.

All of the pollution control bonds financed or refinanced pollution control facilities at the Utility's Geysers geothermal power plant, or the Geysers Project, or at the Utility's Diablo Canyon nuclear power plant, or Diablo Canyon. In 1999, the Utility sold the Geysers Project to Geysers Power Company LLC, a subsidiary of Calpine Corporation. The Geysers Project purchase and sale agreements state that Geysers Power Company LLC will use the facilities solely as pollution control facilities within the meaning of Section 103(b)(4)(F) of the Internal Revenue Code and associated regulations, or the Code. On February 3, 2006, Geysers Power Company LLC filed for reorganization under Chapter 11. The Utility believes that the Geysers Project will continue to meet the use requirements of the Code.

Commercial Paper Program

On January 10, 2006, the Utility entered into various agreements to establish the terms and procedures for the issuance of up to \$1 billion of unsecured commercial paper by the Utility for general corporate purposes. The commercial paper will not be registered under the Securities Act of 1933 or applicable state securities laws and may not be offered or sold in the United States without registration under the Securities Act of 1933 or applicable state securities laws or an applicable exemption from registration requirements. The commercial paper may have maturities of up to 365 days and will rank equally with the Utility's unsubordinated and unsecured indebtedness. At September 30, 2006, the Utility had \$281 million of commercial paper outstanding at an average interest rate of approximately 5.38%. Commercial paper notes are sold at an interest rate dictated by the market at the time of issuance.

Rate Reduction Bonds

In December 1997, PG&E Funding LLC, a limited liability corporation wholly owned by and consolidated by the Utility, issued \$2.9 billion of RRBs. The proceeds of the RRBs were used by PG&E Funding LLC to purchase from the Utility the right, known as "transition property," to be paid a specified amount from a charge levied on residential and small commercial customers. The total principal amount of RRBs outstanding at September 30, 2006 was approximately \$366 million. The RRBs outstanding are scheduled to mature on December 26, 2007.

While PG&E Funding LLC is a wholly owned consolidated subsidiary of the Utility, it is legally separate from the Utility. The assets of PG&E Funding LLC are not available to creditors of the Utility or PG&E Corporation, and the transition property is not legally an asset of the Utility or PG&E Corporation. The RRBs are secured solely by the transition property and there is no recourse to the Utility or PG&E Corporation.

Energy Recovery Bonds

In 2005, PERF issued two separate series of ERBs in the aggregate amount of \$2.7 billion. 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 DRC. DRC charges are authorized by the CPUC under state legislation and will be paid by the Utility's electricity

customers until the ERBs are fully retired. The total principal amount of ERBs outstanding at September 30, 2006 was approximately \$2.4 billion.

While PERF is a wholly owned consolidated subsidiary of the Utility, PERF is legally separate from the Utility. The assets of PERF (including the recovery property) 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's and the Utility's changes in shareholders' equity for the nine months ended September 30, 2006 were as follows:

(in millions)	PG&E Corporation	Utility
	Total Common Shareholders' Equity	Total Shareholders' Equity
Balance at December 31, 2005	\$ 7,218	\$ 7,650
Net income	839	826
Common stock issued	108	-
PG&E Corporation common stock repurchased:		
Settlement of accelerated share repurchase obligation -March 2006	(58)	-
Settlement of accelerated share repurchase obligation - June 2006	(56)	-
Common restricted stock amortization	15	-
Common stock dividends paid	(228)	(345)
Common stock dividends declared but not yet paid	(116)	-
Preferred stock dividends	-	(10)
Tax benefit from share-based payment awards	38	42
Balance at September 30, 2006	<u>\$ 7,760</u>	<u>\$ 8,163</u>

Stock Repurchases

On November 16, 2005, PG&E Corporation entered into an accelerated share repurchase arrangement, or ASR, with Goldman Sachs & Co., or GS&Co., under which PG&E Corporation repurchased and retired 31,650,300 shares of its outstanding common stock for an initial aggregate purchase price of approximately \$1.1 billion, or \$34.75 per share. Under the share forward agreement related to the ASR, certain additional payments were required by both PG&E Corporation and GS&Co., including a price adjustment based on the difference between the initial purchase price and the average of the daily volume weighted average price of PG&E Corporation common stock over a seven-month period. The price adjustment and any additional payment obligations could be settled, at PG&E Corporation's option, in cash or in shares of its common stock, or a combination of the two. Until the ASR was completed or terminated, GAAP required PG&E Corporation to assume that it would issue shares to settle its obligations. PG&E Corporation calculated the number of shares that would have been required to satisfy its obligations upon completion of the ASR based on the market price of PG&E Corporation's common stock at the end of the reporting period. The number of shares that would be required to satisfy the obligations was treated as outstanding for purposes of calculating diluted EPS. To reflect the potential dilution that existed while the share forward obligations were outstanding, PG&E Corporation treated approximately 1 million additional shares of PG&E Corporation common stock as outstanding for purposes of calculating diluted EPS for the nine months ended September 30, 2006 (see Note 6 below). On March 31, 2006 and June 13, 2006, PG&E Corporation paid GS&Co. approximately \$58 million and \$56 million, respectively (net of amounts payable by GS&Co. to PG&E Corporation), in accordance with the terms of the ASR. PG&E Corporation's payments to GS&Co. reduced common shareholders' equity. PG&E Corporation has no remaining obligation under the November 2005 ASR.

Dividends

On February 16, June 22, and September 21, 2006, the Utility paid common stock dividends totaling \$371 million, including \$345 million of common stock dividends paid to PG&E Corporation and \$26 million of common stock dividends paid to PG&E Holdings, LLC, a wholly owned subsidiary of the Utility.

On January 16, April 15, July 15, and October 15, 2006, PG&E Corporation paid common stock dividends of \$0.33 per share, totaling \$488 million, including \$33 million of common stock dividends paid to Elm Power Corporation, a wholly owned subsidiary of PG&E Corporation. PG&E Corporation and the Utility record common stock dividends declared to Reinvested Earnings.

On February 15, May 15, and August 15, 2006, the Utility paid a cash dividend on various series of its preferred stock outstanding totaling \$10 million. On September 20, 2006, the Board of Directors of the Utility declared a cash dividend on various series of its preferred stock payable on November 15, 2006 to shareholders of record on October 31, 2006.

NOTE 6: 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” prior to exercising the conversion option and meet the criteria of a participating security. The Convertible Subordinated Notes are convertible, at the option of the holders, into 18,558,655 common shares. All PG&E Corporation's participating securities participate on a 1:1 basis in dividends with common shareholders.

PG&E Corporation applies the treasury stock method of reflecting the dilutive effect of outstanding stock-based compensation in the calculation of diluted EPS in accordance with SFAS No. 128, “Earnings Per Share,” or SFAS No. 128. SFAS No. 128 requires that proceeds from the exercise of options and warrants shall be assumed to be used to purchase common shares at the average market price during the reported period. The incremental shares, the difference between the number of shares assumed issued upon exercise and the number of shares assumed purchased, must be included in the number of weighted average common shares used for the calculation of diluted EPS.

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

(in millions, except share amounts)	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2006	2005	2006	2005
Net income	\$ 393	\$ 252	\$ 839	\$ 737
Less: distributed earnings to common shareholders	115	111	344	334
Undistributed earnings	278	141	495	403
Less: undistributed earnings from discontinued operations	-	13	-	13
Undistributed earnings from continuing operations	\$ 278	\$ 128	\$ 495	\$ 390
Common shareholders earnings				
<i>Basic</i>				
Distributed earnings to common shareholders	\$ 115	\$ 111	\$ 344	\$ 334
Undistributed earnings allocated to common shareholders - continuing operations	264	122	469	371
Undistributed earnings allocated to common shareholders - discontinued operations	-	12	-	12
Total common shareholders earnings, basic	\$ 379	\$ 245	\$ 813	\$ 717
<i>Diluted</i>				
Distributed earnings to common shareholders	\$ 115	\$ 111	\$ 344	\$ 334
Undistributed earnings allocated to common shareholders - continuing operations	264	122	469	371
Undistributed earnings allocated to common shareholders - discontinued operations	-	12	-	12
Total common shareholders earnings, diluted	\$ 379	\$ 245	\$ 813	\$ 717
Weighted average common shares outstanding, basic	347	372	345	376
9.50% Convertible Subordinated Notes	19	19	19	19

Weighted average common shares outstanding and participating securities, basic	366	391	364	395
Weighted average common shares outstanding, basic	347	372	345	376
Employee share-based compensation and accelerated share repurchase program ⁽¹⁾	2	4	4	4
Weighted average common shares outstanding, diluted	349	376	349	380
9.50% Convertible Subordinated Notes	19	19	19	19
Weighted average common shares outstanding and participating securities, diluted	368	395	368	399
Net earnings per common share, basic				
Distributed earnings, basic	\$ 0.33	\$ 0.30	\$ 1.00	\$ 0.89
Undistributed earnings - continuing operations, basic	0.76	0.33	1.36	0.99
Undistributed earnings - discontinued operations, basic	-	0.03	-	0.03
Total	\$ 1.09	\$ 0.66	\$ 2.36	\$ 1.91
Net earnings per common share, diluted				
Distributed earnings, diluted	\$ 0.33	\$ 0.30	\$ 0.99	\$ 0.88
Undistributed earnings - continuing operations, basic	0.76	0.32	1.34	0.98
Undistributed earnings - discontinued operations, basic	-	0.03	-	0.03
Total	\$ 1.09	\$ 0.65	\$ 2.33	\$ 1.89

⁽¹⁾ Includes approximately one million shares treated as outstanding in connection with the November 2005 ASR for the nine months ended September 30, 2006 (see Note 5 for further discussion). The remaining approximately three million shares relate to share-based compensation and are deemed to be outstanding in accordance with SFAS No. 128 for the purpose of calculating EPS for the nine months ended September 30, 2006.

Options to purchase 23,000 shares of PG&E Corporation common stock were excluded from the computation of diluted EPS for the three and nine months ended September 30, 2005 because the exercise prices of these options were greater than the average market price of PG&E Corporation common stock over these periods. All options to purchase shares of PG&E Corporation common stock were included in the computation of diluted EPS for the three and nine months ended September 30, 2006 because the option exercise prices of these options were lower than the average market price of PG&E Corporation common stock over these periods.

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

NOTE 7: RISK MANAGEMENT ACTIVITIES

Commodity Procurement Activities

The Utility enters into contracts to procure electricity, natural gas, nuclear fuel, and firm transmission rights. Except for contracts that meet the definition of normal purchases and sales, all derivative contracts, including contracts designated as cash flow hedges of natural gas in the natural gas portfolios, are recorded at fair value and presented as PRM assets and liabilities on the balance sheet. On PG&E Corporation's and the Utility's Condensed Consolidated Balance Sheets, PRM activities consist of \$21 million in Current Assets - Prepaid expenses and other, \$48 million in Other Noncurrent Assets - Other, \$208 million in Current Liabilities - Other, and \$66 million in Noncurrent Liabilities - Other as of September 30, 2006, and \$140 million in Current Assets - Prepaid expenses and other, \$212 million in Other Noncurrent Assets - Other, and \$2 million in Current Liabilities - Other as of December 31, 2005. Since these contracts are used within the regulatory framework, regulatory accounts are recorded to offset the costs and proceeds of these derivatives recognized in earnings and subsequently recovered in regulated rates charged to customers. The Utility recorded \$15 million as long-term regulatory liabilities, \$12 million as current regulatory liabilities, and \$29 million as regulatory assets from cash flow hedges at September 30, 2006, compared to \$59 million as long-term regulatory liabilities, \$2 million as current regulatory liabilities, and less than \$1 million as regulatory assets at December 31, 2005.

Credit risk is the risk of loss that PG&E Corporation and the Utility would incur if customers or counterparties failed to perform their contractual obligations. The Utility is exposed to a concentration of credit risk associated with receivables from the sale of natural gas and electricity to residential and small commercial customers in northern and central California. This credit risk exposure is mitigated by requiring deposits from new customers and from those customers whose past payment practices are below standard. A material loss associated with the regional concentration of retail receivables is not considered likely.

Additionally, the Utility has a concentration of credit risk associated with its wholesale counterparties mainly in the energy industry, including other 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. This concentration of counterparties may impact the Utility's overall exposure to credit risk because counterparties may be similarly affected by economic or regulatory changes, or other changes in conditions. If a counterparty failed to perform on its contractual obligation to deliver electricity, then the Utility may need to procure electricity at current market prices, which may be higher than those originally contracted. Credit losses attributable to receivables and electrical and gas procurement activities from both retail and wholesale customers and counterparties are expected to be recoverable from customers through rates and, therefore, are not expected to have a material impact on earnings.

The Utility manages credit risk for its wholesale customers or counterparties by assigning credit limits based on an evaluation of their financial condition, net worth, credit rating, and other credit criteria as deemed appropriate. Credit limits and credit quality are monitored frequently and a detailed credit analysis is performed at least annually. Further, the Utility relies on 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 contractual specified limits.

The schedule below summarizes the Utility's net credit risk exposure, 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, 2006 and December 31, 2005:

(in millions)	Gross Credit Exposure Before Credit Collateral ⁽¹⁾			Number of Wholesale Customers or Counterparties >10%	Net Exposure to Wholesale Customers or Counterparties >10%	
		Credit Collateral	Net Credit Exposure ⁽²⁾			
September 30, 2006	\$	212	\$ 23	\$ 189	2	\$ 107
December 31, 2005		447	105	342	3	165

⁽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. The Utility's gross credit exposure includes wholesale activity only.

⁽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.

NOTE 8: SHARE-BASED COMPENSATION

On January 1, 2006, the PG&E Corporation 2006 Long-Term Incentive Plan, or 2006 LTIP, became effective. The 2006 LTIP permits the award of various forms of incentive awards, including stock options, stock appreciation rights, restricted stock awards, restricted stock units, performance shares, performance units, deferred compensation awards, and other stock-based awards, to eligible employees of PG&E Corporation and its subsidiaries. Non-employee directors of PG&E Corporation are also eligible to receive restricted stock and either stock options or restricted stock units under the formula grant provisions of the 2006 LTIP. A maximum of 12 million shares of PG&E Corporation common stock (subject to adjustment for changes in capital structure, stock dividends, or other similar events) have been reserved for issuance under the 2006 LTIP, of which 11,429,162 shares were available for award at September 30, 2006.

The 2006 LTIP replaced the PG&E Corporation Long-Term Incentive Program, which expired on December 31, 2005. Awards made under the PG&E Corporation Long-Term Incentive Program before December 31, 2005 and that are still

outstanding continue to be governed by the terms and conditions of the PG&E Corporation Long-Term Incentive Program. Some of the stock options that are still outstanding under the PG&E Corporation Long-Term Incentive Program have associated dividend equivalents.

PG&E Corporation and the Utility use an estimated annual forfeiture rate of 2%, 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 share-based incentive awards for the three and nine months ended September 30, 2006:

(in millions)	PG&E Corporation		Utility	
	Three Months	Nine Months	Three Months	Nine Months
	Ended	Ended	Ended	Ended
	September 30,	September 30,	September 30,	September 30,
	2006	2006	2006	2006
Stock Options	\$ 3	\$ 9	\$ 2	\$ 6
Restricted Stock	4	15	3	11
Performance Shares	(1)	20	(1)	14
Total Compensation Expense (pre-tax)	\$ 6	\$ 44	\$ 4	\$ 31
Total Compensation Expense (after-tax)	\$ 4	\$ 26	\$ 2	\$ 18

As discussed in Note 2, "New and Significant Accounting Policies - Share-Based Payment," effective January 1, 2006, PG&E Corporation adopted the fair value recognition provisions for share-based payment using the modified prospective application method provided by SFAS No. 123R.

Stock Options

Stock options are granted with an exercise price equal to the market price of PG&E Corporation's stock at the date of grant and generally vest over four years of continuous service. The options have a 10-year contractual term.

The fair value of each stock option is estimated on the date of grant using the Black-Scholes valuation method. The weighted average grant date fair value of options granted using the Black-Scholes valuation method was \$6.98 and \$8.51 per share in 2006 and 2005, respectively. The significant assumptions used for shares granted in 2006 and 2005 were:

	2006	2005
Expected stock price volatility	22.1%	40.6%
Expected annual dividend payment	\$ 1.32	\$ 1.20
Risk-free interest rate	4.46%	3.74%
Expected life	5.6 years	5.9 years

Expected volatilities are based on historical volatility of PG&E Corporation's common stock. The expected life of stock options is derived from historical data that estimates stock option exercise and employee departure behavior. The risk-free interest rate for periods within the contractual term of the stock option is based on the U.S. Treasury rates in effect at the date of grant.

The following table summarizes total intrinsic value of options exercised during the three and nine months ended September 30, 2006:

(in millions)	PG&E Corporation		Utility	
	Three Months	Nine Months	Three Months	Nine Months
	Ended	Ended	Ended	Ended
	September 30,	September 30,	September 30,	September 30,
2006:				
Intrinsic value of options exercised	\$ 18	\$ 79	\$ 9	\$ 41
2005:				
Intrinsic value of options exercised	\$ 28	\$ 118	\$ 13	\$ 52

The tax benefit from options exercised totaled \$34 million for the period ended September 30, 2006, of which approximately \$40 million was recognized by the Utility.

The following table summarizes stock option activity for PG&E Corporation and the Utility for the nine months ended September 30, 2006:

Options	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2006	11,899,059	\$ 23.26		
Granted ⁽¹⁾	12,457	37.47		
Exercised	(4,542,714)	22.47		
Forfeited or expired	(120,556)	24.96		
Outstanding at September 30, 2006	7,248,246	24.09	5.6	\$ 159,222,487
Exercisable at September 30, 2006	4,924,480	18.42	4.1	\$ 92,773,369

⁽¹⁾ No stock options were awarded to employees in 2006; however, certain non-employee directors of PG&E Corporation were awarded stock options.

The following table summarizes stock option activity for the Utility for the nine months ended September 30, 2006:

Options	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2006	7,371,761	\$ 23.15		
Granted	-	-		
Exercised	(2,395,596)	22.30		
Forfeited or expired	(96,974)	24.76		
Outstanding at September 30, 2006	4,879,191	23.56	5.9	\$ 107,769,131
Exercisable at September 30, 2006	3,245,709	18.90	4.5	\$ 63,933,389

As of September 30, 2006, there was approximately \$13 million of total unrecognized compensation cost, of which \$9 million related to the Utility. That cost is expected to be recognized over a weighted average period of 1.9 years for PG&E Corporation and over a weighted average period of 1.8 years for the Utility.

Restricted Stock

During the nine months ended September 30, 2006, PG&E Corporation awarded 548,555 shares of PG&E Corporation restricted common stock to eligible participants of PG&E Corporation and its subsidiaries, of which 387,600 shares were awarded to the Utility's eligible participants.

The restricted shares are held in an escrow account. The shares become available to the employees as the restrictions lapse. For the restricted stock awarded in 2003, the restrictions on 80% of the shares lapse automatically over a period of four years at the rate of 20% per year. Restrictions on the remaining 20% of the shares will lapse at a rate of 5% per year if PG&E Corporation's annual total shareholder return, or TSR, is in the top quartile of its comparator group as measured at the end of the immediately preceding year. For restricted stock awarded in 2004 and 2005, there are no performance criteria and the restrictions will lapse ratably over four years. For restricted stock awarded in 2006, the restrictions on 60% of the shares will lapse automatically over a period of three years at the rate of 20% per year. If PG&E Corporation's annual TSR is in the top quartile of its comparator group as measured for the three immediately preceding calendar years, the restrictions on the

remaining 40% of the shares will lapse on the first business day of 2009. If PG&E Corporation's TSR is not in the top quartile for such period, then the restrictions on the remaining 40% of the shares will lapse on the first business day of 2011. Compensation expense related to the portion of the 2006 restricted stock award

subject to conditions based on TSR is recognized over the shorter of the requisite service period and three years.

The tax benefit from restricted stock settlements totaled \$4 million for the nine months ended September 30, 2006, of which approximately \$2 million was recognized by the Utility. There was no tax benefit from restricted stock settlements for the three months ended September 30, 2006 for PG&E Corporation or the Utility.

The following table summarizes restricted stock activity for PG&E Corporation and the Utility for the nine months ended September 30, 2006:

	Number of Shares of Restricted Stock	Weighted Average Grant- Date Fair Value
Nonvested at January 1, 2006	1,399,990	\$ 22.31
Granted	548,555	37.47
Vested	(493,874)	20.97
Forfeited	(79,095)	18.33
Nonvested at September 30, 2006	<u>1,375,576</u>	<u>29.18</u>

The following table summarizes restricted stock activity for the Utility for the nine months ended September 30, 2006:

	Number of Shares of Restricted Stock	Weighted Average Grant- Date Fair Value
Nonvested at January 1, 2006	958,997	\$ 22.47
Granted	387,600	37.47
Vested	(340,396)	21.08
Forfeited	(65,522)	19.53
Nonvested at September 30, 2006	<u>940,679</u>	<u>29.37</u>

As of September 30, 2006, there was approximately \$21 million of total unrecognized compensation cost, of which \$15 million related to the Utility. PG&E Corporation and the Utility expect to recognize this cost over a weighted average period of 1.6 years.

Performance Shares

During the nine months ended September 30, 2006, PG&E Corporation awarded 548,555 performance shares to certain officers and employees of PG&E Corporation and its subsidiaries, of which 387,600 shares were awarded to certain Utility officers and employees. Performance shares are hypothetical shares of PG&E Corporation common stock that vest at the end of a three-year period and are settled in cash. Upon vesting, the amount of cash that recipients are entitled to receive is based on the average closing price of PG&E Corporation stock for the last 30 calendar days of the year preceding the vesting date and a payout percentage, ranging from 0% to 200%, as measured by PG&E Corporation's TSR relative to its comparator group for the applicable three-year period.

The following table summarizes performance share activity for PG&E Corporation and the Utility for the nine months ended September 30, 2006:

	Number of Performance Shares
Nonvested at January 1, 2006	803,975
Granted	548,555
Vested	-
Forfeited	<u>(21,062)</u>

The following table summarizes performance shares activity for the Utility for the nine months ended September 30, 2006:

	Number of Performance Shares
Nonvested at January 1, 2006	566,086
Granted	387,600
Vested	-
Forfeited	(20,507)
Nonvested at September 30, 2006	<u>933,179</u>

Outstanding performance shares are classified as a liability on the Condensed Consolidated Financial Statements of PG&E Corporation and the Utility because the performance shares can only be settled in cash upon satisfaction of the performance criteria. The liability related to the performance shares is marked to market at each reporting date to reflect the market price of PG&E Corporation common stock and the payout percentage at the end of the reporting period. Accordingly, compensation expense recognized for performance shares will fluctuate with PG&E Corporation's common stock price and its performance relative to its peer group.

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 costs and allocations 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 of the services. PG&E Corporation also allocates certain other corporate administrative and general costs, at cost, 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 and related receivable (payable) balances were as follows:

(in millions)	Three Months Ended		Nine Months Ended		Receivable (Payable) Balance Outstanding at	
	September 30,		September 30,		September 30,	December 31,
	2006	2005	2006	2005	2006	2005
Utility revenues from:						
Administrative services provided to PG&E Corporation	\$ 1	\$ 1	\$ 3	\$ 4	\$ 1	\$ 2
Utility employee benefit assets due from PG&E Corporation	(1)	-	(2)	-	21	23
Interest from PG&E Corporation on employee benefit assets	-	-	1	-	-	-
Utility expenses from:						
Administrative services received from PG&E Corporation	\$ 24	\$ 21	\$ 72	\$ 70	\$(38)	\$(37)

NOTE 10: THE UTILITY'S EMERGENCE FROM CHAPTER 11

The Utility emerged from Chapter 11 when its plan of reorganization became effective on April 12, 2004. The plan of reorganization incorporated the terms of the Settlement Agreement. Although the Utility's operations are no longer subject to the oversight of the Bankruptcy Court, the Bankruptcy Court retains jurisdiction to hear and determine disputes arising in connection with the interpretation, implementation, or enforcement of (1) the Settlement Agreement, (2) the plan of reorganization, and (3) the Bankruptcy Court's December 22, 2003 order confirming the plan of reorganization, or confirmation order. In addition, the Bankruptcy Court retains jurisdiction to resolve remaining disputed claims. Refer to the 2005 Annual Report for a further discussion of the Utility's emergence from Chapter 11.

On March 16, 2006, the U.S. Court of Appeals for the Ninth Circuit, or Ninth Circuit, dismissed as moot an appeal of the confirmation order. The appeal had been filed by two former commissioners of the CPUC who did not vote to approve the Settlement Agreement. On March 30, 2006, one of the two former commissioners filed a petition for rehearing with the

Ninth Circuit. On April 7, 2006, the Ninth Circuit denied the petition. The time period during which the former commissioners could have filed a petition for rehearing with the U.S. Supreme Court has expired, rendering the confirmation order final and no longer subject to appeal.

As of September 30, 2006 and December 31, 2005, the Utility had accrued approximately \$1.2 billion for remaining net disputed claims, consisting of approximately \$1.7 billion of accounts payable-disputed claims primarily payable to the California Independent System Operator, or ISO, and the California Power Exchange, or PX, offset by an accounts receivable amount from the ISO and the PX of approximately \$0.5 billion. The Utility held approximately \$1.2 billion in escrow, which is recorded as restricted cash, for the payment of the remaining disputed claims as of September 30, 2006 and December 31, 2005. Upon resolution of these claims and under the terms of the Settlement Agreement, any net refunds, claims, offsets, or other credits that the Utility receives from energy suppliers will be returned to customers, less deductions for contingencies, amounts related to certain wholesale power purchases and amounts due to shareholders. With the approval of the Bankruptcy Court, the Utility has withdrawn certain amounts from escrow in connection with settlements with certain ISO and PX sellers.

NOTE 11: COMMITMENTS AND CONTINGENCIES

PG&E Corporation and the Utility have substantial financial commitments and contingencies in connection with agreements entered into supporting the Utility's operating activities.

Commitments

PG&E Corporation

In addition to material commitments related to the Utility and disclosed elsewhere in the Notes to the Condensed Consolidated Financial Statements, at September 30, 2006, PG&E Corporation has a commitment relating to natural gas pipeline firm transportation contracts effective November 1, 2007 through October 31, 2023. The firm quantity under the contracts is approximately 50 million cubic feet per day and PG&E Corporation has estimated that annual reservation charges will range between approximately \$8 million and \$10 million.

Utility

Power Purchase Agreements

As part of the ordinary course of business, throughout the year, the Utility enters into various agreements to purchase energy and makes payments on existing power purchase agreements. At September 30, 2006, the expected payments for power purchase agreements based on September 30, 2006 forward prices were as follows:

(in millions)

2006	\$	542
2007		2,072
2008		1,998
2009		1,744
2010		1,516
Thereafter		11,304
Total	\$	19,176

Payments made by the Utility under power purchase agreements amounted to approximately \$1,863 million for the nine months ended September 30, 2006, and \$1,535 million for the same period in 2005. As the Utility acts as only an agent for the California Department of Water Resources, or DWR, the amounts described above do not include payments related to DWR power purchases.

The CPUC is considering various policy and pricing issues related to power purchased from QFs in several rulemaking proceedings. It is expected that a proposed decision addressing those issues will be issued soon. In April 2006, the Utility and the Independent Energy Producers on behalf of certain QFs entered into a settlement agreement to resolve these issues irrespective of how the CPUC ultimately resolves these issues. These issues remain unresolved for the QFs that did not accept the terms of the settlement agreement. On July 20, 2006, the CPUC approved the settlement agreement and amendments relating to QFs which became effective once the CPUC decision became final and non-appealable on August 21, 2006. As of September 30, 2006, 122 QFs are subject to an amendment of their existing contracts with the Utility to

reduce the Utility's energy payments and to establish a new five-year fixed pricing option for non-natural gas-fired QFs. The settlement agreement also resolves certain energy crisis claims among the Utility and the settling QFs that are pending in another CPUC proceeding. When a final decision addressing these issues is issued by the CPUC, the Utility will re-evaluate the accounting treatment for QF contracts that are affected by the decision.

As a result of the amendments, several of the QF contracts became subject to lease accounting under SFAS No. 13, "Accounting for Leases," or SFAS No. 13, due to the nature of the fixed capacity payments. SFAS No. 13 requires the Utility to recognize capital lease obligations and assets equal to the present value of the fixed capacity payments under the QF agreements that are treated as capital leases. Accordingly, the Utility recorded Current Liabilities - Other and Non-Current Liabilities - Other of approximately \$26 million and \$378 million, respectively, as of September 30, 2006, representing the present value of the fixed capacity payments due under these contracts. The corresponding assets of \$408 million are included in plant, property and equipment on the Utility's Condensed Consolidated Balance Sheet at September 30, 2006. The Utility's Condensed Consolidated Balance Sheet also reflects accumulated amortization related to the leased assets of \$4 million at September 30, 2006.

The following table shows the future fixed capacity payments due under the QF contracts that are treated as capital leases. (These amounts are also included in the table above). The fixed capacity payments are discounted to the present value shown 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)

2006	\$	11
2007		50
2008		50
2009		50
2010		50
Thereafter		352
Total fixed capacity payments		563
Less: Amount representing interest		(159)
Present value of fixed capacity payments	\$	404

Interest and amortization expense associated with the lease obligation is included in the cost of electricity on the Utility's Condensed Consolidated Statement of Income. In accordance with SFAS No. 71, the timing of the Utility's recognition of the lease expense will conform to the ratemaking treatment for the Utility's recovery of the cost of electricity. The QF contracts that are treated as capital leases expire between April 2014 and September 2021.

Capacity payments are based on the QF's total available capacity and contractual capacity commitment. Capacity payments may be adjusted if the QF fails to meet or exceeds 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 the United States and Canada to serve its residential and small commercial, or core, gas customers. The contract lengths and natural gas sources of the Utility's portfolio of natural gas procurement contracts have fluctuated, generally based on market conditions.

At September 30, 2006, the Utility's expected payments for natural gas purchases based on September 30, 2006 forward prices and gas transportation services based on existing contract prices were as follows:

(in millions)

2006	\$	421
2007		860
2008		30
2009		25
2010		8
Thereafter		-
Total	\$	1,344



Payments made by the Utility for natural gas purchases and gas transportation services amounted to approximately \$1,654 million for the nine months ended September 30, 2006 and \$1,584 million for the same period in 2005.

Nuclear Fuel Agreements

The Utility has entered into purchase agreements for nuclear fuel. These agreements have terms ranging from three to six years and are intended to ensure long-term fuel supply. Pricing terms also are diversified, ranging from fixed prices to market-based prices to base prices that are escalated using published indices.

At September 30, 2006, the undiscounted obligations under nuclear fuel agreements were as follows:

(in millions)		
2006	\$	63
2007		125
2008		86
2009		71
2010		93
Thereafter		453
Total	\$	891

Payments made by the Utility for nuclear fuel amounted to approximately \$41 million for the nine months ended September 30, 2006 and approximately \$65 million for the same period in 2005.

Reliability Must Run Agreements

The ISO has entered into reliability must run, or RMR, agreements with various power plant owners, including the Utility, that require designated units in certain power plants, known as RMR units, to remain available to generate electricity upon the ISO's demand when needed for local transmission system reliability. As a participating transmission owner under the Transmission Control Agreement with the ISO, the Utility is responsible for the ISO's costs paid under RMR agreements to power plant owners within or adjacent to the Utility's service territory. At September 30, 2006, the Utility estimated that it could be obligated to pay the ISO approximately \$59 million for costs to be incurred under these RMR agreements during the period October 1, 2006 to December 31, 2006.

The Utility recovers those costs it incurs under RMR agreements in rates from customers under the Utility's FERC-jurisdictional transmission owner tariff, without mark-up or service fees. The Utility tracks these costs and related recoveries in the reliability services balancing account. Periodically, the Utility's electricity transmission rates are adjusted to refund over-collections to the Utility's customers or to collect any under-collections from customers. The Utility estimates it will receive approximately \$5 million during the same period under the RMR agreements that the Utility has with the ISO for the Utility's units that have been designated as RMR units.

RMR agreements are established or extended on an annual basis. It is likely that the number of RMR agreements and the associated costs will be reduced in 2007 because many or all local transmission system reliability issues may be addressed through the CPUC's Local Resource Adequacy Requirements proceeding.

In November 2001, the Utility and other interested California parties filed a complaint with the FERC against RMR owners other than the Utility, alleging that certain rates under those owners' RMR agreements with the ISO were unlawfully high and proposing that the FERC apply a ratemaking methodology to these other RMR agreements that would significantly reduce those rates. The FERC dismissed the complaint in 2005. In September 2005, the Utility and other interested California parties filed a petition for review of the FERC's decision with the United States Court of Appeals for the District of Columbia Circuit, or D.C. Circuit. On June 19, 2006, the D.C. Circuit granted the FERC's requested remand of the appeal to permit further consideration of the case by the FERC.

On January 26, 2006, the FERC permitted new RMR rates for two RMR plants owned by affiliates of Calpine Corporation to become effective, subject to possible refund after the rate cases are concluded either through a FERC-approved settlement or a FERC decision following evidentiary hearings. The new rates increased the Utility's RMR payments for these facilities by approximately \$70 million per year over the amounts paid in 2005. In addition, on August 1, 2006, the Utility filed claims in the Chapter 11 proceedings of several affiliates of Calpine Corporation that own RMR plants, including the two affiliates with the pending rate cases discussed above, seeking refunds of RMR costs that the Utility paid in the approximate aggregate amount of \$98 million. On October 12, 2006, several Calpine Corporation affiliates, the Utility,

and the California Electricity Oversight Board signed a settlement agreement resolving these and other FERC cases, including the case filed in November 2001 discussed in the preceding paragraph and the Utility's claims in the Chapter 11 proceedings of several Calpine Corporation affiliates. Obligations under the settlement agreement, such as refunds to the Utility and certain power contracts between the Utility and various Calpine Corporation affiliates, will become effective only after the settlement has been approved by the CPUC, the FERC, and the bankruptcy court adjudicating the Chapter 11 proceedings of the Calpine Corporation affiliates. The refunds that the Utility may obtain in connection with the resolution of these cases will be credited to the Utility's electricity customers. For the Utility's RMR contract payments through September 2006, the refunds are expected to total \$43 million, with an additional \$16 million in estimated refunds resulting from RMR contract payments for the remainder of 2006.

Underground Electric Facilities

At September 30, 2006, the Utility was committed to spending approximately \$228 million for the conversion of existing overhead electric facilities to underground electric facilities. These funds are conditionally committed depending on the timing of the work, including the schedules of the respective cities and counties and telephone utilities involved. The Utility expects to spend approximately \$50 million to \$60 million each year in connection with these projects. Consistent with past practice, the Utility expects that these capital expenditures will be included in rate base as each individual project is completed and recoverable in rates charged to customers.

Contingencies

PG&E Corporation

PG&E Corporation retains one guarantee related to certain indemnity obligations of its former subsidiary, National Energy & Gas Transmission, Inc., or NEGT, that were issued to the purchaser of an NEGT subsidiary company during 2000. The underlying indemnity obligations of NEGT have expired and PG&E Corporation's sole remaining exposure of up to \$150 million relates to any potential environmental obligations that were known to NEGT at the time of the sale but not disclosed to the purchaser. PG&E Corporation has never received any claims nor does it consider it probable that any claims will be made under the guarantee. Accordingly, PG&E Corporation has made no provision for this guarantee at September 30, 2006.

Utility

PX Block-Forward Contracts

In February 2001, during the energy crisis, the California Governor seized all of the Utility's contracts for the forward delivery of power in the PX California market, otherwise known as "block-forward contracts," for the benefit of the state under California's Emergency Services Act. These block-forward contracts had an estimated unrealized value of up to \$243 million at the time the State of California seized them. The Utility, the PX, and some of the PX market participants have filed competing claims in state court against the State of California to recover the value of these seized contracts. In November 2005, the PX assigned its interest in this litigation to certain market participants that elected to take assignment of the litigation, subject to the terms and conditions of a settlement agreement approved by the FERC. A motion by the PX for court approval of the assignment is pending in the Sacramento Superior Court; the State of California disputes this assignment. The State of California also disputes the plaintiffs' rights to recovery in the litigation and disputes that the plaintiffs were damaged in any way, arguing that the contracts had no value beyond the price at which the block-forward transactions were executed. This state court litigation is pending. Although the Utility has recorded a receivable of approximately \$243 million relating to the estimated value of the contracts at the time of seizure, the Utility also has established a reserve of \$243 million for these contracts. If the Utility ultimately prevails, it would record income in the amount of any recovery. PG&E Corporation and the Utility are unable to predict the outcome of this litigation or the amount of any potential recovery.

California Energy Crisis Proceedings

FERC Proceedings

Various entities, including the Utility and the State of California, are seeking refunds from energy suppliers in the California ISO and PX markets for electricity overcharges on behalf of California electricity purchasers for the period May 2000 to June 2001 through various proceedings pending at the FERC and judicial proceedings. The first refund proceeding at the FERC commenced on August 2, 2000 when a complaint was filed against all suppliers in the ISO and PX markets. The FERC

determined that it only had authority to order refunds pursuant to this complaint for the period beginning 60 days after the complaint was filed (i.e., October 2, 2000). Other FERC proceedings for violation of the FERC's market manipulation rules are also pending.

In March 2003, the FERC accepted a judge's initial decision that power suppliers overcharged the utilities, the State of California, and other buyers by approximately \$1.8 billion from October 2, 2000 to June 20, 2001. On August 2, 2006, the Ninth Circuit issued an opinion finding that the FERC had erred in excluding certain types of transactions as eligible for price mitigation within the existing FERC refund period (October 2, 2000 - June 20, 2001) and requiring the FERC to investigate possible tariff violations, market manipulation, and anomalous bidding practices that may have occurred before October 2, 2000. The Ninth Circuit also found that the FERC could not refuse to consider the need for a market-wide remedy (as opposed to company-specific prosecutions) for market manipulation and tariff violations that may have occurred before October 2, 2000. Requests for rehearing of this Ninth Circuit decision are due on February 28, 2007. The Ninth Circuit's expansion of the types of transactions that the FERC must review and the expansion of the time period could result in additional refunds. The Ninth Circuit ruling addressed which transactions were subject to refund, but left to later proceedings questions about how refunds are calculated.

In its March 2003 order, the FERC also modified the refund methodology to include use of a new natural gas price methodology and indicated that energy suppliers could request a reduction in the amount of refunds that the FERC may find they owe by the amount of any higher actual natural gas costs that they incurred. Various energy suppliers submitted their audited natural gas cost reports to the ISO in November 2005. The FERC also allowed energy suppliers to provide information about their costs to determine the extent to which refunds, if ordered, would result in sales revenue below their costs. The FERC has issued various decisions on the cost information filed by energy suppliers, but some issues remain unresolved and the August 2, 2006 Ninth Circuit order may require revisions to those filings. The FERC also directed the ISO and the PX to make compliance filings to enable the FERC to establish the amount of refunds. These compliance filings cannot be made until the FERC finalizes its decisions on the cost information filed by energy suppliers.

In September 2005, the Ninth Circuit issued a partial decision finding that the FERC did not have the authority to compel governmental and municipal utilities to provide refunds. The Utility and other California parties intend to file a request for rehearing of this decision by November 13, 2006. On March 16, 2006, the California utilities and the California Electric Oversight Board filed a lawsuit in federal district court against 19 municipal and governmental entities seeking refunds. Additional refund claims also are being pursued against several other governmental entities. On October 24, 2006, arguments were held on motions to dismiss the litigation seeking refunds from the municipal and governmental entities. A decision on the motions to dismiss is expected by the end of 2006. The Utility is unable to predict the outcome of the decision or the impact it could have on settlement discussions.

Final refunds will not be determined by the FERC until the FERC rules on the energy suppliers' filings, the ISO and PX rerun their market data and submit their compliance filings, the FERC addresses the issues remanded to it by the Ninth Circuit, and pending and future appeals are resolved.

The Utility has entered into settlements with various power suppliers resolving certain disputed claims and the Utility's refund claims against these power suppliers. The Utility has recorded credits of approximately \$1 billion under these settlements, including the settlements described below. These settlement agreements provide that the amounts payable by the parties are, in some instances, subject to adjustment based on the ultimate judicial determination of the FERC's refund authority, and the FERC's final decisions regarding refund amounts, cost filings, gas and emissions recovery and allocation, and interest. Additional settlement discussions with other energy suppliers are ongoing. Future amounts received under these settlements, and any future settlements with energy suppliers, will be credited to customers.

Enron Settlement

In November 2005, the FERC approved an agreement among the Utility, the California Attorney General, the DWR, Southern California Edison, San Diego Gas & Electric Company, the California Electric Oversight Board, and the CPUC (collectively, the California Parties), along with the Attorneys Generals of the States of Oregon and Washington, the FERC's Office of Market Oversight and Investigations (collectively, the Other Parties), and Enron Corporation and various of its subsidiaries, or Enron, to satisfy Enron's liabilities to make refunds.

The settlement provides that Enron would pay \$47 million in cash to the California Parties and the Other Parties and allow them an unsecured claim of \$875 million in the bankruptcy proceedings of Enron Power Marketing, Inc., a subsidiary through which Enron conducted its power marketing operations in California, to settle electric and gas market overcharges. Of these amounts, the Utility expects to ultimately receive approximately \$12 million in cash, over time, and approximately

\$346 million of the unsecured bankruptcy claim. In February 2006, the Utility received cash proceeds of approximately \$20 million, consisting of \$5 million from the cash portion of the settlement proceeds and \$15 million as a partial distribution of the allowed unsecured bankruptcy claim, which was credited to customers. In April 2006, the Utility received a second distribution on its allowed unsecured bankruptcy claim, consisting of \$41 million in cash and 281,828 shares of Portland General Electric (formerly owned by Enron) common stock. The Utility subsequently sold all of the shares of Portland General Electric common stock, realizing approximately \$8 million in net proceeds. The cash proceeds from both the second distribution and the sale of the stock, after deductions for contingencies, amounts related to certain wholesale power purchases, and amounts due to shareholders, were credited to the Utility's customers. In October 2006, the Utility received a third distribution on its allowed unsecured bankruptcy claim, consisting of \$28 million in cash and 24,471 shares of Portland General Electric common stock. The proceeds from this distribution will be credited to customers. The final value of the bankruptcy claim will not be determined until the conclusion of Enron's bankruptcy case unless liquidated earlier in a secondary market for such claims.

Reliant Settlement

In December 2005, the FERC approved an agreement among the Utility, the Attorneys General of the States of Oregon and Washington, the DWR, the FERC's Office of Market Oversight and Investigations, Southern California Edison, San Diego Gas & Electric Company, and Reliant Energy, Inc. and various of its subsidiaries, or Reliant, to resolve claims against Reliant for gas and electric market manipulation and overcharges during the California energy crisis in 2000 and 2001.

Under the terms of the agreement, Reliant assigned to the counterparties approximately \$300 million of its receivables from the ISO or the PX and agreed to pay the counterparties an additional \$131 million in cash. In 2005, the Utility recognized approximately \$105 million of its share of Reliant's assigned receivable from the ISO or the PX as a reduction in the Utility's payable to the PX. Additionally, in March 2006, the Utility received approximately \$88 million in cash for its share of initial cash proceeds. These proceeds, after deductions for contingencies, amounts related to certain wholesale power purchases and amounts due to shareholders, have been credited to the Utility's customers. The Utility expects to receive additional cash proceeds of approximately \$10 million over time.

Mirant Settlement

In January 2005, the Utility and other parties entered into a settlement agreement with Mirant Corporation and certain of its subsidiaries, or Mirant, related to claims outstanding in Mirant's Chapter 11 proceeding. The FERC and Mirant's bankruptcy court approved the settlement in April 2005.

The first part of the two-part settlement is among Mirant, the California Attorney General's Office, the DWR, the CPUC, Southern California Edison, San Diego Gas & Electric Company, and the Utility, among others, resolving market manipulation claims against Mirant and Mirant's liability for FERC refunds, penalties, and civil liabilities arising out of the California energy crisis in 2000 and 2001. Under this portion of the agreement, Mirant provided approximately \$320 million in cash equivalents and \$175 million of allowed claims in the bankruptcy proceeding of Mirant America's Energy Marketing, LP. Of these amounts, the Utility received approximately \$134 million in a combination of cash and a cash-equivalent reduction in the Utility's payable to the PX. Additionally, the Utility received approximately \$45 million in allowed claims excluding interest, which the Utility sold in December 2005 for approximately \$48 million, including interest owed by Mirant. The consideration received, after deductions for contingencies, amounts related to certain wholesale power purchases and amounts due to shareholders, has been credited to the Utility's customers.

The second part of the settlement is between the Utility and Mirant, and is designed to settle claims that Mirant overcharged the Utility under Mirant's RMR contracts and other disputes. In January 2006, under the terms of the settlement agreement, the Utility received consideration, in the form of cash and new Mirant stock, of approximately \$43 million in settlement of an RMR claim and \$20 million in settlement of a claim relating to sulfur dioxide emission allowances. These proceeds were credited to the Utility's customers during the quarter ended March 31, 2006. In addition, Mirant agreed to transfer to the Utility the equipment, permits, and contracts for the construction of a modern 530-megawatt, or MW, electric generating facility known as Contra Costa Unit 8 which Mirant had started to build but never completed. On June 13, 2006, the FERC authorized Mirant to transfer Contra Costa Unit 8 to the Utility. On June 15, 2006, the CPUC approved the Utility's application to acquire Contra Costa Unit 8, to complete construction, and to operate the facility. The completion of the acquisition remains subject to the satisfaction of a number of closing conditions. If the Utility and Mirant do not close the acquisition of Contra Costa Unit 8 on or before June 30, 2008, the Utility will be paid \$70 million from an escrow account funded by Mirant in lieu of transferring the assets. Also, in accordance with the settlement, the Utility entered into contracts with several of Mirant's units in the Utility's service territory. On July 28, 2006, the Utility and Mirant entered into two new

contracts, which both supplemented and partially superseded the contracts from the settlement, resulting in further savings to the Utility's customers. The new contracts, one for the 2007 period and one for a multi-year period beginning in January 2008, give the Utility the right to dispatch power from 1,985 MW of units owned by Mirant subsidiaries when the facilities are not needed by the ISO to meet local reliability needs. On August 4, 2006, the Utility filed an advice letter seeking CPUC approval for the multi-year contract and expects possible approval during the fourth quarter of 2006.

Scheduling Coordinator Costs

Before the ISO commenced operation in 1998, the Utility had entered into several wholesale electric transmission contracts with various governmental entities. After the ISO began operations, the Utility served as the scheduling coordinator, or SC, with the ISO for these existing wholesale transmission customers, or ETCs. The ISO billed the Utility for providing certain services associated with this scheduling. These ISO charges are referred to as "SC costs." The SC costs were initially tracked in the transmission revenue balancing account, or TRBA, in order to recover the SC costs from retail and new wholesale transmission customers, or TO Tariff customers.

In 1999, a FERC administrative law judge, or ALJ, ruled that the Utility could not recover the SC costs through the TRBA and instead should seek to recover the SC costs from the ETCs. The Utility appealed this ruling. In January 2000, the FERC accepted a filing by the Utility to establish the Scheduling Coordinator Services, or SCS, Tariff, to serve as an alternative mechanism for recovery of the SC costs from the ETCs in case the Utility's appeal was unsuccessful and the Utility was ultimately unable to recover these costs in the TRBA. In August 2002, the FERC affirmed the ALJ's 1999 ruling that the Utility should refund to TO Tariff customers the SC costs that the Utility had collected through the TRBA. In the absence of an order from the FERC granting recovery of these costs through the TRBA, the Utility removed the SC costs from the TRBA and reflected the SC costs as accounts receivable under the SCS Tariff. The Utility appealed the FERC's decision to the D.C. Circuit. In June 2004, the Utility began billing the ETCs under the SCS Tariff for SC charges retroactive to April 1, 1998. In the course of the SCS Tariff proceeding at the FERC, the Utility entered into settlement agreements with several ETCs under which the settling ETCs paid the Utility compromised amounts in full satisfaction of past due SC costs. Most of the settlement agreements provided that if the Utility's pending appeal to the D.C. Circuit was successful, the Utility would refund the settlement amounts paid by the ETCs.

In July 2005, the D.C. Circuit issued an order finding that the Utility was not barred from recovering the SC costs through the TRBA and remanded the matter to the FERC for further action. In December 2005, the FERC issued an order concluding that the Utility should recover the SC costs through the TRBA mechanism or through bilateral agreements with the ETCs, but could not recover the costs through the SCS Tariff, and the FERC terminated the SCS Tariff proceeding. On May 22, 2006, the FERC issued an order further clarifying that the Utility could recover through the TRBA all of the costs that it had incurred as an SC and ordered the Utility to refund to the ETCs all amounts paid by the ETCs to the Utility pursuant to the SCS Tariff. As of July 31, 2006, the Utility had made refunds to the ETCs pursuant to the FERC's May 2006 order and the settlement agreements that required refunds to be made if the Utility's appeal was successful.

On April 4, 2006, the Utility filed an application with the FERC seeking approval of the \$109 million that the Utility recorded as SC costs from April 1998 through July 2005, together with interest of \$47 million accrued over that time period. The Utility requested that the FERC permit the Utility to recover these costs from TO Tariff customers over three and one-half years. On June 22, 2006, the Utility filed additional information to supplement the application as directed by the FERC. The Utility also filed an advice letter with the CPUC notifying the CPUC that the Utility will seek to pass through the portion of any FERC-approved SC costs that is allocable to the Utility's retail electric customers. In light of these events, in the quarter ended June 30, 2006, the Utility's net income increased by approximately \$22 million, or \$37 million pre-tax, reflecting the portion of SC costs determined to be probable of recovery through the TRBA and the reversal of a reserve for SC costs under the SCS Tariff which was terminated by the FERC, offset by SCS refunds to the ETCs.

On August 31, 2006, the Utility received an order from the FERC approving the Utility's April 4, 2006 application. On September 30, 2006, the order was no longer subject to rehearing or appeal. In light of this FERC order, the Utility determined that all SC costs are probable of recovery from TO Tariff customers through the TRBA, resulting in an overall increase to the Utility's pre-tax income of \$92 million and \$129 million, respectively, for the three and nine months ended September 30, 2006, reflecting SC costs incurred from April 1998 through September 2006. SC costs incurred after September 30, 2006 and in the future are considered probable of recovery through the TRBA.

Nuclear Insurance

The Utility has several types of nuclear insurance for Diablo Canyon and its retired nuclear facility at Humboldt Bay, or Humboldt Bay Unit 3. The Utility has insurance coverage for property damages and business interruption losses as a

member of Nuclear Electric Insurance Limited, or 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 \$41.4 million per one-year policy term.

NEIL also provides coverage for damages caused by acts of terrorism at nuclear power plants. If one or more acts of domestic terrorism cause property damage covered under any of the nuclear insurance policies issued by NEIL to any NEIL member within a 12-month period, the maximum recovery under all those nuclear insurance policies may not exceed \$3.24 billion plus the additional amounts recovered by NEIL for these losses from reinsurance. There is no policy coverage limitation for an act caused by foreign terrorism because NEIL would be entitled to receive substantial reimbursement by the federal government under the Terrorism Risk Insurance Extension Act of 2005. The Terrorism Risk Insurance Extension Act of 2005 expires on December 31, 2007.

Under the Price-Anderson Act, public liability claims from a nuclear incident are limited to \$10.8 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 \$10.8 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, are designed for the production of electrical energy, and have a rated capacity of 100 MW or higher. If a nuclear incident results in costs in excess of \$300 million, then the Utility may be responsible for up to \$100.6 million per reactor, with payments in each year limited to a maximum of \$15 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 \$201.2 million per incident, with payments in each year limited to a maximum of \$30 million per incident. Under the Energy Policy Act of 2005, the Price-Anderson Act was extended through December 31, 2025. Both the maximum assessment per reactor and the maximum yearly assessment will be adjusted for inflation beginning August 31, 2008.

In addition, the Utility has \$53.3 million of liability insurance for the retired nuclear generating unit at Humboldt Bay power plant 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 .

California Department of Water Resources Contracts

Electricity from the DWR contracts to the Utility provided approximately 23% of the electricity delivered to the Utility's customers for the nine months ended September 30, 2006. The DWR purchased the electricity under contracts with various generators. The Utility, as an agent, is responsible for administration and dispatch of the DWR's electricity procurement contracts allocated to the Utility for purposes of meeting a portion of the Utility's net open position. The Utility's net open position is the portion of the Utility's customer demand, plus the applicable reserve margins that is not satisfied from the Utility's own generation facilities and existing electricity contracts. The DWR remains legally and financially responsible for its electricity procurement contracts. The Utility acts as a billing and collection agent of the DWR's revenue requirements from the Utility's customers.

The DWR contracts currently allocated to the Utility terminate at various dates through 2015 and consist of must-take and capacity charge contracts. Under must-take contracts, the DWR must take and pay for electricity generated by the applicable generating facilities regardless of whether the electricity is needed. Under capacity charge contracts, the DWR must pay a capacity charge but is not required to purchase electricity unless the Utility dispatches the resource and the resource delivers the required electricity. In the Utility's CPUC-approved long-term electricity procurement plan, the Utility has not assumed that the DWR contracts will be renewed beyond their current expiration dates.

The DWR has stated publicly in the past that it intends to transfer full legal title to, 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. The 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 will be no less than A2 and the Utility's long-term issuer credit rating by Standard & Poor's Ratings Services will be no less than A;

- 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.

Severance in Connection with Efforts to Achieve Cost and Operating Efficiencies

In connection with the Utility's continued effort to streamline processes and achieve cost and operating efficiencies through implementation of various initiatives, jobs from numerous Utility locations around California are being consolidated. As a result, a number of positions have been eliminated. The Utility expects that more positions will be eliminated by the end of 2007. Impacted employees have the option to elect severance or reassignment.

Estimating severance costs requires the Utility to predict whether employees will elect severance or reassignment, and the number of available vacant positions for employees wishing to be reassigned. Depending on the employees' elections, costs will further vary based on the employees' years of service and annual salary. Given the uncertainty of each of these variables, the estimated range is relatively wide. At September 30, 2006, the Utility's future severance expenses related to these initiatives are expected to range from \$10 million to approximately \$99 million, of which the Utility has recorded approximately \$10 million as of September 30, 2006. The following table presents the changes in the liability from December 31, 2005:

(in millions)

Balance at December 31, 2005	\$	2
Expenses		9
Less: Payments		(1)
Balance at September 30, 2006	\$	<u>10</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 the Comprehensive Environmental Response Compensation and Liability Act of 1980, as amended, and similar state environmental laws. These sites include former manufactured gas plant sites, power plant sites, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous materials. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances 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 that remediation is probable and it can estimate a range of reasonably likely clean-up costs. The Utility reviews its remediation liability on a quarterly basis for each site where it may be exposed to remediation responsibilities. The liability is an estimate of costs for site investigations, remediation, operations and maintenance, monitoring, and site closure using current technology, 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. 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 estimates the upper end of the cost range using reasonably possible outcomes least favorable to the Utility.

The Utility had an undiscounted environmental remediation liability of approximately \$513 million at September 30, 2006 and approximately \$469 million at December 31, 2005. The increase in the undiscounted environmental remediation liability reflects an increase of \$63 million for the nine months ended September 30, 2006 for remediation at the Utility's gas compressor stations located near Hinkley, California and Topock, Arizona. The Utility had accrued \$54 million of this increase at June 30, 2006. The portion of the increased liability of \$32 million for remediation at the Hinkley facility is attributable to changes in the California Regional Water Quality Control Board's imposed remediation levels. Costs incurred at this facility are not recoverable from customers and, as a result, net income was reduced by \$19 million for the nine months ending September 30, 2006. Ninety percent of the estimated remediation costs associated with the Utility's gas compressor station located near Topock, Arizona will be recoverable in rates in accordance with the hazardous waste ratemaking mechanism which permits the Utility to recover 90% of hazardous waste remediation costs from customers

without a reasonableness review. The \$513 million accrued at September 30, 2006 includes approximately \$235 million for remediation at gas compressor sites, approximately \$100 million related to the pre-closing remediation liability associated with divested generation facilities, and approximately \$178 million related to remediation costs for those generation facilities that the Utility still owns, gas gathering sites, third-party disposal sites, and manufactured gas plant sites that either are owned by the Utility or are the subject of remediation orders by environmental agencies or claims by the current owners of the former manufactured gas plant sites. Of the \$513 million environmental remediation liability, approximately \$139 million has been included in prior rate setting proceedings. The Utility expects that an additional \$297 million will be allowable for inclusion 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 \$779 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. The amount of approximately \$779 million does not include an estimate for the cost of remediation at known sites owned or operated in the past by the Utility's predecessor corporations for which the Utility has not been able to determine whether a liability exists.

Taxation Matters

The Internal Revenue Service, or IRS, has completed its audit of PG&E Corporation's 1997 and 1998 consolidated federal income tax returns and has assessed additional federal income taxes of approximately \$87 million (including interest). PG&E Corporation filed protests contesting certain adjustments made by the IRS in that audit. In April 2006, PG&E Corporation and the IRS Appeals Office resolved the remaining contested adjustment. The IRS Appeals Office is incorporating the results into its final report. However, the IRS Appeals Office has not indicated when it will complete its report.

The IRS is currently auditing PG&E Corporation's 2001 and 2002 consolidated federal income tax returns. The IRS is proposing to disallow a number of deductions claimed in PG&E Corporation's 2001 and 2002 tax returns. The largest of these deductions is a deduction for abandoned or worthless assets owned by NEGT. In addition, the IRS is proposing to disallow \$104 million of synthetic fuel credits claimed in PG&E Corporation's 2001 and 2002 tax returns. If the IRS includes all of its proposed disallowances in its final Revenue Agent Report, the alleged tax deficiency would approximate \$452 million. PG&E Corporation believes that it properly reported these transactions in its tax returns and will contest any IRS assessment. The IRS has indicated that it plans to complete its audit of PG&E Corporation's 2001 and 2002 tax returns and issue a Revenue Agent Report in the first quarter of 2007.

The IRS is also in the early stages of an audit of PG&E Corporation's 2003 and 2004 consolidated federal income tax returns and has not yet proposed any new adjustments to these tax returns.

As of September 30, 2006, PG&E Corporation has accrued approximately \$138 million to cover potential non-Utility tax obligations and interest related to outstanding audits, including \$89 million related to the proposed disallowance of deduction for abandoned or worthless assets owned by NEGT discussed above, and \$49 million to cover potential tax obligations related to non-NEGT issues. The Utility has accrued \$52 million as of September 30, 2006 to cover potential tax obligations for outstanding audits.

After considering the above accruals, PG&E Corporation and the Utility do not expect the final resolution of the outstanding audits to have a material impact on their financial condition or results of operations .

In the third quarter of 2006, PG&E Corporation recorded tax benefits of approximately \$19 million with respect to capital losses carried forward and used in its 2005 federal and California income tax returns. The 2005 federal and California income tax returns were filed in August 2006 and October 2006, respectively. PG&E Corporation has \$209 million of remaining capital loss carry forwards, which, if not used by December 2009, will expire. These capital losses resulted from PG&E Corporation's disposition of its ownership interest in NEGT in 2004.

Legal Matters

In the normal course of business, PG&E Corporation and the Utility are named as parties in a number of claims and lawsuits. The most significant of these are discussed below.

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 case. In assessing such contingencies, PG&E Corporation's and the Utility's policy is to exclude anticipated legal costs.

The accrued liability for legal matters is included in PG&E Corporation's and the Utility's other current liabilities in the Condensed Consolidated Balance Sheets, and totaled approximately \$71 million at September 30, 2006 and \$388 million at December 31, 2005. The decrease in the accrued liability for legal matters is primarily due to payments made under the chromium litigation settlement agreement discussed below.

PG&E Corporation and the Utility do not believe it is probable that losses associated with legal matters that exceed amounts already recognized will be incurred in amounts that would be material to PG&E Corporation's or the Utility's financial condition or results of operations .

Chromium Litigation

In accordance with the terms of a settlement agreement entered into on February 3, 2006, on April 21, 2006, the Utility released \$295 million from escrow for payment to approximately 1,100 plaintiffs who had filed complaints against the Utility in the Superior Court for the County of Los Angeles, or Superior Court. The Superior Court has dismissed the 10 complaints covered by the settlement agreement. There are three complaints filed by approximately 125 plaintiffs who did not participate in the settlement that are still pending in the Superior Court. The plaintiffs allege that exposure to chromium at or near the Utility's compressor station at Hinkley, California caused personal injuries, wrongful deaths, or other injuries.

With respect to the unresolved claims, the Utility will continue to pursue appropriate defenses, including the statute of limitations, the exclusivity of workers' compensation laws, lack of exposure to chromium, and the inability of chromium to cause certain of the illnesses alleged.

PG&E Corporation's and the Utility's Condensed Consolidated Balance Sheets at September 30, 2006 include an accrual of approximately \$19 million to reflect the remaining unresolved claims. PG&E Corporation and the Utility do not expect that the outcome with respect to the remaining unresolved claims will have a material adverse effect on their financial condition or results of operations.

Pending CPUC Investigation

In February 2005, the CPUC issued a ruling opening an investigation into the Utility's billing and collection practices and credit policies. The investigation was begun at the request of The Utility Reform Network, or TURN, after the CPUC's January 13, 2005 decision that characterized the definition of " billing error " in a revised Utility tariff to include delayed bills and Utility-caused estimated bills as being consistent with " existing CPUC policy, tariffs, and requirements. " The Utility contends that prior to the CPUC's January 13, 2005 decision, " billing error " under the Utility's former tariffs did not encompass delayed bills or Utility-caused estimated bills. The Utility's petition asking the appellate court to review the CPUC's decision denying rehearing of its January 13, 2005 decision is still pending.

On February 3, 2006, the CPUC's Consumer Protection and Safety Division, or CPSD, and TURN submitted their reports to the CPUC concluding that the Utility violated applicable tariffs related to delayed and estimated bills. The CPSD recommended that the Utility refund to customers \$117 million, plus interest at the three-month commercial paper interest rate, that allegedly was collected in violation of the tariffs. TURN recommended that the Utility refund to customers \$53 million, plus interest at the three-month commercial paper interest rate, that allegedly was collected in violation of the tariffs. The two refunds are not additive. The CPSD also recommended that the Utility pay fines of \$6.75 million, while TURN recommends fines in the form of a \$1 million contribution to Relief for Energy Assistance through Community Help. Both the CPSD and TURN recommend that refunds and fines be funded by shareholders. In May and July 2006, the CPSD and TURN indicated they had reduced their recommended refund amounts to approximately \$54 million and \$36 million, respectively, plus interest at the three-month commercial paper interest rate . It is uncertain when the CPUC will issue a final decision.

If the CPUC finds that the Utility violated applicable tariffs or the CPUC's orders or rules, the CPUC may seek to order the Utility to refund any amounts collected in violation of tariffs, plus interest, to customers who paid such amounts. In addition, if the CPUC finds that the Utility violated applicable tariffs or the CPUC's orders or rules, the CPUC may seek to impose penalties on the Utility.

PG&E Corporation and the Utility do not expect that the outcome of this matter will have a material adverse effect 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 company whose primary purpose is to hold interests in energy-based businesses. The company conducts its business principally through Pacific Gas and Electric Company, or the Utility, a public utility operating in northern and central California. The Utility engages primarily 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.

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 and a variable interest entity which the Utility is required to consolidate under applicable accounting standards. This combined Management's Discussion and Analysis of Financial Condition and Results of Operations, or MD&A, of PG&E Corporation and the Utility should be read in conjunction with these Condensed Consolidated Financial Statements and Notes to the Condensed Consolidated Financial Statements, as well as the MD&A, Consolidated Financial Statements and Notes to the Consolidated Financial Statements incorporated by reference into their joint Annual Report on Form 10-K for the year ended December 31, 2005 filed with the Securities and Exchange Commission, or SEC. PG&E Corporation's and the Utility's combined Annual Report on Form 10-K for the year ended December 31, 2005, together with the information incorporated by reference into such report, is referred to in this quarterly report as the "2005 Annual Report."

The Utility served approximately 5.1 million electricity distribution customers and approximately 4.2 million natural gas distribution customers at September 30, 2006. The Utility had approximately \$34.4 billion in assets at September 30, 2006 and generated revenues of approximately \$9.3 billion in the nine months ended September 30, 2006.

The Utility is regulated primarily by the California Public Utilities Commission, or CPUC, and the Federal Energy Regulatory Commission, or FERC. The Utility's revenues are generated 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, or rate base. Changes in any individual revenue requirement affect customers' rates and could affect the Utility's revenues. Pending regulatory proceedings that could result in rate changes and affect the Utility's revenues are discussed in the 2005 Annual Report. Significant developments that have occurred since the 2005 Annual Report was filed with the SEC are discussed in this report.

Summary of Changes in Earnings per Common Share and Net Income for the Three and Nine Months Ended September 30, 2006

PG&E Corporation's diluted earnings per common share, or EPS, for the three and nine months ended September 30, 2006 were \$1.09 per share and \$2.33 per share respectively, compared to the same periods in 2005 of \$0.65 per share and \$1.89 per share, respectively. The increase in diluted EPS for the nine months ended September 30, 2006 is primarily due to the FERC's approval of recovery of certain costs the Utility began incurring in 1998 in its capacity as scheduling coordinator, or SC, for its existing wholesale electricity transmission customers, the recovery of certain interest and litigation costs related to disputed generator claims that the Utility recognized following completion of the CPUC's verification audit in the Utility's 2005 annual electric true-up proceeding, or AET, and a lower number of shares outstanding following the November 2005 repurchase of 31,650,300 shares of PG&E Corporation common stock. The increase in EPS for the three months ended September 30, 2006 is primarily due to the same factors as for the year to date, and also due to increased gas transmission revenues compared to the same period in 2005. On a year to date basis, the increased gas transmission revenues were more than offset by the carrying cost credit associated with the second series of energy recovery bonds, or ERBs, issued in November 2005.

For the three and nine months ended September 30, 2006, PG&E Corporation's net income increased by \$141 million, or 56%, and by \$102 million, or 14%, respectively, compared to the same periods in 2005. The recognition of recovery of SC costs, resulted in an increase to net income of approximately \$55 million and \$77 million, for the three and nine months ended September 30, 2006, respectively, as compared to the same periods in 2005 (see further discussion in "Regulatory

Matters - Scheduling Coordinator Costs” below). During the third quarter of 2006, the Utility’s net income also increased by approximately \$39 million due to the recovery of certain interest and litigation costs incurred in connection with disputed generator claims. Additionally, increased gas transmission revenues in the third quarter increased net income by approximately \$7 million. On a year to date basis, the increased gas transmission revenues were more than offset by the carrying cost credit associated with the second series of ERBs issued in November 2005.

Factors Affecting Financial Condition and Results of Operations

In addition to the changes affecting net income as described above, several factors have had, and are expected to continue to have, a significant impact on PG&E Corporation's and the Utility's financial condition and results of operations, including:

- *The Outcome of Regulatory Proceedings, Including the 2007 General Rate Case* - Various regulatory proceedings are pending at the FERC and the CPUC, including the Utility’s 2007 General Rate Case, or GRC, which is pending at the CPUC to determine the amount of the Utility’s authorized base revenues to be collected from customers for the period 2007 through 2009. On August 21, 2006, the Utility, together with various parties, requested the CPUC to approve a settlement agreement reached among the parties to resolve all of the issues raised by these parties and all revenue requirement related issues raised by other parties in the Utility’s 2007 GRC proceeding. The revenue requirement amounts set forth in the settlement agreement reflect an increase of \$222 million in the Utility's electric distribution revenues, an increase of \$21 million in gas distribution revenues, and a decrease of \$30 million in generation operation revenues for an overall increase of \$213 million over the authorized 2006 amounts. The settlement agreement also includes attrition increases for 2008, 2009, and 2010. On October 19, 2006, the CPUC approved the Utility’s request to make its 2007 test year GRC revenue requirement effective on January 1, 2007, since the CPUC is scheduled to issue a final decision after that date.
- *The Success of the Utility’s Strategy to Achieve Operational Excellence and Improved Customer Service* - During 2006, the Utility is continuing to undertake various initiatives to implement changes to its business processes and systems in an effort to provide better, faster and more cost-effective service to its customers. The Utility believes that the proposed amounts of the attrition adjustments for 2008, 2009 and 2010 included in the proposed GRC settlement agreement will be sufficient in light of the estimated cost savings anticipated to be realized from implementation of these initiatives. If the actual cost savings are greater than anticipated, such benefits would accrue to shareholders. Conversely, if these cost savings are not realized, earnings available for shareholders would be reduced.
- *The Amount and Timing of Capital Expenditures* - The Utility has requested regulatory approval of various capital expenditures to fund (1) investments in transmission and distribution infrastructure needed to serve its customers (i.e., to extend the life of existing infrastructure, to replace existing infrastructure, and to add new infrastructure to meet load growth), and (2) investment in new long-term generation resources, as may be authorized by the CPUC in accordance with the Utility’s long-term electricity procurement plan. The CPUC also has authorized the Utility to deploy its advanced metering infrastructure, or AMI, project and authorized the Utility to recover its estimated project cost of \$1.7 billion, including \$1.4 billion of estimated capital costs, in rates.

- *Proposed New Long-Term Generation Resources* - On April 11, 2006, the Utility filed an application with the CPUC seeking approval of seven agreements for new long-term electricity generation resource commitments, including five power purchase agreements (four of which have been executed) and two contracts that provide for the construction by third parties of two new power plants to be owned and operated by the Utility. One of these contracts calls for the construction of a 657-megawatt, or MW, power plant and the other contract calls for the construction of a 163-MW power plant at the Utility's Humboldt Bay facility. On October 17, 2006, a proposed decision was issued recommending approval of the seven agreements. The Utility anticipates that the CPUC will issue a final decision on the Utility's application by the end of the year. Assuming that the CPUC approves the agreements and that permitting and construction schedules are met, the new generation facilities are anticipated to begin delivering power to the grid in 2009 and 2010. In addition, on June 15, 2006, the CPUC approved the Utility's application to acquire and build a 530-MW power plant to be located in Contra Costa County, or Contra Costa Unit 8.
- *Capital Structure* - The CPUC has granted the Utility a waiver to file a cost of capital application for 2007 and allowed the Utility to maintain the Utility's 2006 authorized cost of capital and capital structure, including the Utility's authorized equity component of 52% and the authorized, return on equity, or ROE, of 11.35%.
- *Issuance of Energy Recovery Bonds* - During 2005, PG&E Energy Recovery Funding LLC, a limited liability company wholly owned by the Utility, or PERF, issued two separate series of ERBs for an aggregate amount of approximately \$2.7 billion. In February 2005, the proceeds of the first series of ERBs in the amount of \$1.9 billion were used to refinance the after-tax portion of the settlement regulatory asset established by the settlement agreement among PG&E Corporation, the Utility and the CPUC to resolve the Utility's Chapter 11 proceeding, or Chapter 11 Settlement Agreement. From January 1, 2005 through the date of the refinancing the Utility earned approximately \$12 million, after tax, on the after-tax settlement regulatory asset calculated at the Utility's authorized 11.22% ROE for 2005. The Utility's earnings after the refinancing no longer include an ROE on the settlement regulatory asset. The November 2005 issuance of the second series of ERBs in the amount of \$844 million was used to pre-fund the Utility's tax liability that will be due as the Utility collects the dedicated rate component used to secure repayment of the first series of ERBs from its customers. Until these taxes are fully paid, the Utility provides customers a carrying cost credit. The equity portion of this carrying cost credit reduced the Utility's 2006 net income for the three and nine months ended September 30, 2006 by approximately \$14 million and \$43 million, respectively, as compared to the same periods in 2005. The equity portion of this carrying cost credit is estimated to reduce the Utility's net income in 2006 and 2007 by approximately \$55 million and \$48 million. The equity portion of the carrying cost credit will decline each year over the term of the ERBs until the ERBs are fully repaid in 2012.
- *Chromium Litigation Settlement* - On April 21, 2006, the Utility paid approximately \$295 million to settle most of the claims involving allegations that exposure to chromium at or near some of the Utility's natural gas compressor stations caused personal injuries, wrongful deaths, or other injuries, referred to as the Chromium Litigation (discussed in Note 11 of the Notes to the Condensed Consolidated Financial Statements). PG&E Corporation and the Utility had previously accrued \$314 million for the settlement and they do not believe that the outcome of the remaining unresolved claims in the Chromium Litigation will have a material adverse effect on their future results of operations or financial condition.

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, the realization or resolution of which are outside of management's control. These statements are based on current expectations and projections about future events, and assumptions regarding these events and management's knowledge of facts at the date of this report. These forward-looking statements relate to estimated capital expenditures, estimated Utility rate base, estimated environmental remediation 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,” “may,” “might,” “should,” “would,” “could,” “goal,” “potential” and similar expressions. PG&E Corporation’s and the Utility’s results of operations and financial condition depend primarily on whether the Utility is able to operate its business within authorized revenue requirements, timely recover its authorized costs, and earn its authorized rate of return. 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, are discussed in the section of the 2005 Annual Report entitled “Risk Factors.” These factors include, but are not limited to:

Operating Environment

- How the Utility manages its responsibility to procure electric capacity and energy for its customers, which can be affected by, among other factors, the extent to which the Utility's distribution customers are permitted to switch between purchasing electricity from the Utility or from alternate energy service providers as direct access customers or from cities, counties and others in the Utility's service territory as community choice aggregators, potentially resulting in stranded generating asset costs and non-recoverable procurement costs, as well as the impact of existing state and potential federal law requirements to comply with greenhouse gas emission standards and to meet renewable energy and resource adequacy targets;
- The adequacy and price of natural gas supplies, and the ability of the Utility to manage and respond to the volatility of the natural gas market for its customers;
- Weather, storms, earthquakes, fires, floods, diseases, other natural disasters, explosions, accidents, mechanical breakdowns, acts of terrorism, and other events or hazards that affect demand for electricity or natural gas, result in power outages, reduce generating output, disrupt natural gas supply, cause damage to the Utility's assets or generating facilities, cause damage to the operations or assets of third parties on which the Utility relies, or subject the Utility to third party claims for damage or injury;
- Unanticipated population growth or decline, general economic and financial market conditions, and changes in technology including the development of alternative energy sources, all of which may affect customer demand for natural gas or electricity;
- Whether the Utility is required to cease operations temporarily or permanently at the Utility’s nuclear power plant, or Diablo Canyon, because the Utility is unable to increase its on-site spent nuclear fuel storage capacity, find another depository for spent fuel, or timely complete the replacement of the steam generators, or because of mechanical breakdown, lack of nuclear fuel, environmental or regulatory constraints, or for some other reason and the risk that the Utility may be required to purchase electricity from more expensive sources; and
- Whether the Utility is able to recognize the benefits expected to result from its efforts to improve customer service through implementation of specific initiatives to streamline business processes and deploy new technology such as its project to deploy an AMI.

Legislative Actions and Regulatory Proceedings

- The outcome of the regulatory proceedings pending at the CPUC and the FERC, including those discussed in “Regulatory Matters” below, and the impact of future ratemaking actions by the CPUC and the FERC;
- The impact of the Energy Policy Act of 2005 which, among other provisions, repealed the Public Utility Holding Company Act of 1935 making electric utility industry consolidation more likely; expanded the FERC’s authority to review proposed mergers; changed the FERC regulatory scheme applicable to qualifying facilities, or QFs; authorized the FERC to oversee an Electric Reliability Organization to establish electric reliability standards and penalty provisions for failure to meet the standards; and modified certain other aspects of energy regulation and federal tax policies applicable to the Utility;

- The impact of wholesale electric or gas market rules, including the California Independent System Operator's, or ISO's, new rules to implement the ISO's Market Redesign and Technology Upgrade initiative, to become effective on November 7, 2007, to restructure the California electricity market, including the establishment of a new day-ahead market, new locational marginal pricing methods, and new ISO systems and interfaces with market participants;
- The extent to which the CPUC or the FERC delays or denies recovery of the Utility's costs, including electricity or gas purchase costs, from customers due to a regulatory determination that such costs were not reasonable or prudent, or for other reasons, resulting in write-offs of regulatory assets;
- How the CPUC administers the capital structure, stand-alone dividend, and first priority conditions of the CPUC's past decisions permitting the establishment of holding companies for the California investor-owned electric utilities and the outcome of the CPUC's new rulemaking proceeding concerning the relationship between the California investor-owned energy utilities and their holding companies and non-regulated affiliates, which may include (1) establishing reporting requirements for the allocation of capital between utilities and their non-regulated affiliates by the parent holding companies, (2) changing the CPUC's affiliate transaction rules, and/or (3) restricting the flow of information and sharing of services among the Utility, PG&E Corporation and PG&E Corporation's other affiliates, if any;
- Whether the Utility is determined to be in compliance with all applicable rules, regulations, tariffs and orders relating to electricity and natural gas utility operations, including those relating to the procurement of renewable energy, resource adequacy, greenhouse gas emissions, electric reliability standards, billing and collection practices as discussed below in "Regulatory Matters," and the extent to which a finding of non-compliance could result in customer refunds, penalties or other non-recoverable expenses; and
- Whether the Utility is required to incur material costs or capital expenditures or curtail or cease operations at affected facilities, including the Utility's natural gas compressor stations, to comply with existing and future environmental laws, regulations and policies, including existing state and potential federal and state laws related to greenhouse gas emissions and global warming.

Pending Litigation

- The outcome of pending litigation.

Municipalization and Bypass

- Continuing efforts by local public utilities to take over the Utility's distribution assets through exercise of their condemnation power or by duplication of the Utility's distribution assets or service, and other forms of municipalization that may result in stranded investment capital, decreased customer growth, loss of customer load and additional barriers to cost recovery.

See the section entitled "Risk Factors" in the 2005 Annual Report and Part II, Item 1A. Risk Factors, below, for further discussion of the more significant risks that could affect the outcome of these forward-looking statements and PG&E Corporation's and the Utility's future financial condition and results of operations.

RESULTS OF OPERATIONS

The table below details certain items from the accompanying Condensed Consolidated Statements of Income for the three and nine-month periods ended September 30, 2006 and 2005:

(in millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Utility				
Electric operating revenues	\$ 2,470	\$ 2,107	\$ 6,547	\$ 5,546
Natural gas operating revenues	698	697	2,786	2,424
Total operating revenues	3,168	2,804	9,333	7,970
Cost of electricity	884	742	2,195	1,626
Cost of natural gas	298	326	1,539	1,293
Operating and maintenance	793	738	2,637	2,179
Depreciation, amortization and decommissioning	456	481	1,290	1,320
Total operating expenses	2,431	2,287	7,661	6,418
Operating income	737	517	1,672	1,552
Interest income	36	20	94	59
Interest expense	(144)	(138)	(447)	(416)
Other income (expense), net ⁽¹⁾	(18)	(7)	6	(3)
Income before income taxes	611	392	1,325	1,192
Income tax provision	236	148	509	457
Income available for common stock	\$ 375	\$ 244	\$ 816	\$ 735
PG&E Corporation, Eliminations and Other ⁽²⁾				
Operating revenues	\$ -	\$ -	\$ -	\$ -
Operating (gain) expenses	2	2	3	(2)
Operating income (loss)	(2)	(2)	(3)	2
Interest income	4	2	10	1
Interest expense	(8)	(7)	(23)	(22)
Other income (expense), net	(4)	(7)	-	(13)
Loss before income taxes	(10)	(14)	(16)	(32)
Income tax benefit	(28)	(9)	(39)	(21)
Income (Loss) From Continuing Operations	18	(5)	23	(11)
Discontinued Operations	-	13	-	13
Net income	\$ 18	\$ 8	\$ 23	\$ 2
Consolidated Total ⁽²⁾				
Operating revenues	\$ 3,168	\$ 2,804	\$ 9,333	\$ 7,970
Operating expenses	2,433	2,289	7,664	6,416
Operating income	735	515	1,669	1,554
Interest income	40	22	104	60
Interest expense	(152)	(145)	(470)	(438)
Other income (expense), net ⁽¹⁾	(22)	(14)	6	(16)
Income before income taxes	601	378	1,309	1,160
Income tax provision	208	139	470	436
Income From Continuing Operations	393	239	839	724
Discontinued Operations	-	13	-	13
Net income	\$ 393	\$ 252	\$ 839	\$ 737

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

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

Utility

Overview

Under cost-of-service ratemaking, the Utility's rates are determined based on its costs of service. The CPUC and the FERC determine the amount of "revenue requirements" that the Utility is authorized to collect from its customers to recover the Utility's operating and capital costs and earn a fair return. Revenue requirements are primarily determined based on the Utility's forecast of future costs, including the costs of purchasing electricity and natural gas on behalf of the Utility's customers. A substantial portion of the Utility revenues are adjusted periodically through revenue balancing account mechanisms to reflect differences between actual sales compared to forecasted sales used in setting rates. The balancing account mechanisms also track differences between actual purchased power and natural gas procurement costs compared to the forecasted amounts used in setting rates.

The Utility currently faces a certain level of volumetric risk for the portion of intrastate natural gas transmission capacity that is not subscribed for under long-term contracts with fixed reservation charges to core customers or other long-term contract holders (see further discussion in the Natural Gas Transportation and Storage section in the section entitled "Risk Management Activities" of the 2005 Annual Report). In addition, the Utility faces some volumetric risk in collecting its full electric transmission revenue requirement authorized in its electric transmission business.

The Utility's primary base revenue requirement proceeding is the GRC filed with the CPUC. In the GRC, the CPUC authorizes the Utility to collect from customers an amount known as base revenues to recover basic business and operational costs related to the Utility's electricity and natural gas distribution and electricity generation operations. The GRC typically sets annual revenue requirement levels for a three-year rate period. The CPUC authorizes these revenue requirements in GRC proceedings based on a forecast of costs for the first, or test, year. In the past, the CPUC has authorized future revenue requirement adjustments (attrition adjustments) in the subsequent years of the GRC cycle. In addition, the CPUC generally conducts an annual cost of capital proceeding to determine the Utility's authorized capital structure and the authorized rate of return that the Utility may earn on its electricity and natural gas distribution and electricity generation assets. The cost of capital proceeding establishes the percentage components that common equity, preferred equity, and debt will represent in the Utility's total authorized capital structure for a specific year. The CPUC then establishes the authorized return on common equity, preferred equity, and debt that the Utility will collect in its authorized rates. The CPUC also has established ratemaking mechanisms to permit the Utility to timely recover its costs to procure electricity and natural gas on behalf of its customers in the energy markets.

The Utility's rates reflect the sum of individual revenue requirement components authorized by the CPUC and the FERC. Changes in any individual revenue requirement affect customers' rates and could affect the Utility's revenues. Pending regulatory proceedings that could result in rate changes and affect the Utility's revenues are discussed in the section entitled "Regulatory Matters" in the 2005 Annual Report. Developments that have occurred in significant regulatory proceedings discussed in the 2005 Annual Report and significant new regulatory matters that have been initiated since the 2005 Annual Report was filed with the SEC are discussed below in the section entitled "Regulatory Matters." In the AET proceeding, the Utility requests the CPUC to authorize an adjustment to electric and gas rates effective on the first day of the following year to (1) reflect over- and under-collections in the Utility's major electric and gas balancing accounts, and (2) consolidate various other electricity and gas revenue requirement changes authorized by the CPUC or the FERC. Although the rate changes become effective on the first day of the following year, balances in all accounts are subject to review, verification audit, and adjustment, if necessary, by the CPUC. The timing of the CPUC and other regulatory decisions affect when the Utility is able to record the authorized revenues.

Electric Operating Revenues

The Utility's electricity rates are determined based on its cost of service. Differences between the authorized revenue requirements and amounts collected by the Utility from customers in rates are tracked in regulatory balancing accounts and are reflected in miscellaneous revenues in the table below.

In addition to electricity provided by the Utility's own generation facilities and electricity provided under the Utility's power purchase agreements with third-party providers, the Utility relies on electricity provided under long-term electricity procurement contracts entered into in 2001 through September 2005 by the California Department of Water Resources, or the DWR, to meet a material portion of its customers' demand. Revenues collected on behalf of the DWR and the DWR's related costs are not included in the Utility's Condensed Consolidated Statements of Income, reflecting the Utility's role as a billing and collection agent for the DWR's sales to the Utility's customers. Changes in the DWR's revenue requirements will not affect the Utility's revenues.

The Utility is required to dispatch, or schedule, all of the electricity resources within its portfolio, including electricity provided under the DWR allocated contracts, in the most cost-effective way. This requirement, in certain cases, requires the Utility to schedule more electricity than is necessary to meet its retail load and to sell this additional electricity on the open market. The Utility typically schedules excess electricity when the expected sales proceeds exceed the variable costs to operate a generation facility or buy electricity under an optional contract. Proceeds from the sale of surplus electricity are allocated between the Utility and the DWR based on the percentage of volume supplied by each entity to the Utility's total load. The Utility's net proceeds from the sale of surplus electricity after deducting the portion allocated to the DWR are recorded as a reduction to the cost of electricity.

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

(in millions)	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2006	2005	2006	2005
Electric revenues	\$ 3,055	\$ 2,507	\$ 8,119	\$ 6,780
DWR pass-through revenue	(585)	(400)	(1,572)	(1,234)
Total electric operating revenues	\$ 2,470	\$ 2,107	\$ 6,547	\$ 5,546
Total electricity sales (in GWh) ⁽¹⁾	24,001	23,306	63,886	61,572

⁽¹⁾ Includes DWR electricity sales.

For the three months ended September 30, 2006, the Utility's electric operating revenues increased by approximately \$363 million, or 17%, compared to the same period in 2005 mainly due to the following factors:

- An increase in electric operating revenues of approximately \$136 million due to a FERC order allowing the Utility to recover SC costs the Utility incurred from April 1998 through September 2006 through the Transmission Revenue Balancing Account, or TRBA (see "Regulatory Matters - Scheduling Coordinator Costs" below);
- Higher electricity procurement costs, including hedging costs, which are passed through to customers, increased electric operating revenues by approximately \$82 million (see "Cost of Electricity" below);
- Upon completion of the 2005 AET verification audit, the Utility recognized approximately \$65 million of revenues due to the recovery of net interest costs charged to the Energy Recovery Bond Balancing Account, or ERBBA, related to net disputed generator claims for the period between the effective date of the Utility's plan of reorganization and the first issuance of ERBs, and for certain energy supplier refund litigation costs (see "Regulatory Matters - Energy Recovery Bond Balancing Account" below);
- The dedicated rate component, or DRC, charge related to the ERBs increased electric operating revenues by approximately \$36 million (see further discussion in Notes 3 and 4 of the Notes to the Condensed Consolidated Financial Statements). During the third quarter of 2005, the Utility collected the DRC charge for the first series of ERBs that were issued on February 10, 2005. During the third quarter of 2006, the Utility collected the DRC associated with the first series of ERBs in addition to the DRC charge related to the second series of ERBs, issued on November 9, 2005;
- Attrition adjustments, as authorized in the 2003 GRC, in which the CPUC approved the minimum and maximum yearly adjustments to the Utility's 2003 base revenue requirements, increased electric operating revenues by approximately \$34 million;
- Higher transmission revenues, including an increase in revenues as authorized in the FERC transmission rate case (see "Regulatory Matters - FERC Transmission Rate Cases" below), increased electric operating revenues by approximately \$24 million;

- The Utility recorded approximately \$28 million in electric revenues representing a portion of an annual revenue requirement authorized by the CPUC to recover a pension contribution attributable to the Utility's GRC lines of business (see "Regulatory Matters - Defined Benefit Pension Plan Contribution" below); and
- Miscellaneous other electric operating revenues, including revenues associated primarily with public purpose programs, the California Alternate Rates for Energy Program, and the Self-Generation Incentive Plan, increased by approximately \$54 million.

The above increases were partially offset by the following decreases to electric operating revenues:

- A decrease to electric operating revenues of approximately \$66 million related to the recovery of costs in 2005 on the deferred tax component of the settlement regulatory asset with no similar amount in 2006; and
- The carrying cost credit, including both the debt and equity components, associated with the issuance of the second series of ERBs decreased electric operating revenues by approximately \$30 million. The second series of ERBs was issued to pre-fund the Utility's tax liability that will be due as the Utility collects the DRC related to the first series of ERBs from its customers over the term of the ERBs. Until these taxes are fully paid, the Utility provides customers a carrying cost credit, computed at the Utility's authorized rate of return on rate base, to compensate them for the use of proceeds from the second series of ERBs (see further discussion in the section entitled "Regulatory Matters" in the 2005 Annual Report).

For the nine months ended September 30, 2006, the Utility's electric operating revenues increased by approximately \$1 billion, or 18%, compared to the same period in 2005 mainly due to the following factors:

- Higher electricity procurement costs, including hedging costs, which are passed through to customers, increased electric operating revenues by approximately \$527 million (see "Cost of Electricity" below);
- The DRC charge related to the ERBs increased electric operating revenues by approximately \$150 million (see further discussion in Notes 3 and 4 of the Notes to the Condensed Consolidated Financial Statements). During the first nine months of 2005, the Utility collected the DRC for the first series of ERBs that were issued on February 10, 2005. During the first nine months of 2006, the Utility collected the DRC associated with the first series of ERBs in addition to the DRC related to the second series of ERBs, issued on November 9, 2005;
- An increase in electric operating revenues of approximately \$136 million due to a FERC order allowing the Utility to recover SC costs the Utility incurred from April 1998 through September 2006 through the TRBA. (See "Regulatory Matters - Scheduling Coordinator Costs" below);
- Higher transmission revenues, including an increase in revenues as authorized in the FERC transmission rate case (see "Regulatory Matters - FERC Transmission Rate Cases" below), increased electric operating revenues by approximately \$96 million;
- Attrition adjustments, as authorized in the 2003 GRC, in which the CPUC approved the minimum and maximum yearly adjustments to the Utility's 2003 base revenue requirements, increased electric operating revenues by approximately \$100 million;
- The Utility recorded approximately \$83 million in electric revenues representing a portion of an annual revenue requirement authorized by the CPUC to recover a pension contribution attributable to the Utility's GRC lines of business (see "Regulatory Matters - Defined Benefit Pension Plan Contribution" below);

- Upon completion of the 2005 AET verification audit, the Utility recognized approximately \$65 million of revenues due to the recovery of net interest costs charged to the ERBBA related to net disputed generator claims for the period between the effective date of the Utility's plan of reorganization and the first issuance of ERBs, and for certain energy supplier refund litigation costs (see further discussion in "Regulatory Matters - Energy Recovery Bond Balancing Account"); and
- Miscellaneous other electric operating revenues, including revenues associated primarily with public purpose programs, the California Alternate Rates for Energy Program, and the Self-Generation Incentive Plan, increased by approximately \$93 million.

The above increases were partially offset by the following decreases to electric operating revenues:

- A decrease to electric operating revenues of approximately \$155 million related to revenue requirements associated with the settlement regulatory asset and the recovery of costs on the deferred tax component of the settlement regulatory asset in 2005, with no similar amounts recorded in 2006; and
- The carrying cost credit, including both the debt and equity components, associated with the issuance of the second series of ERBs decreased electric operating revenues by approximately \$94 million. The second series of ERBs was issued to pre-fund the Utility's tax liability that will be due as the Utility collects the DRC related to the first series from its customers over the term of the ERBs. Until these taxes are fully paid, the Utility provides customers a carrying cost credit, computed at the Utility's authorized rate of return on rate base to compensate them for the use of proceeds from the second series of ERBs (see further discussion in the section entitled "Regulatory Matters" in the 2005 Annual Report).

The Utility's electric operating revenues are expected to increase through the remainder of 2006 primarily due to higher electricity procurement costs, revenues associated with the recovery of the pension contribution, and an attrition adjustment authorized in the 2003 GRC decision. Revenues for the period 2007 through 2009 would also increase to the extent authorized by the CPUC in the 2007 GRC and if the CPUC approves the Utility's proposed new long-term generation resource commitments. (For further discussion, see "2007 General Rate Case" and "Electricity Generation Resources" under "Regulatory Matters" below). In addition, on September 1, 2006, the Utility began collecting estimated costs of its AMI project as authorized by the CPUC in July 2006. (For further discussion of the AMI project, see "Capital Expenditures" below.) The Utility also filed an application with the CPUC seeking to recover costs incurred in connection with severe storms that occurred in the first half of 2006 and a period of unusually high temperatures that occurred in July 2006 referred to as a "heat storm." (For further discussion, see "Regulatory Matters - Catastrophic Event Memorandum Account Application" below.) In addition, revenues associated with the DRC charge for both series of ERBs are expected to be collected through 2012.

Cost of Electricity

The Utility's cost of electricity includes electricity purchase costs and the cost of fuel used by its owned generation facilities but excludes costs to operate the Utility's generation facilities, which are included in operating and maintenance expense. Electricity purchase costs and the cost of fuel used by owned generation facilities are passed through in rates to customers (see "Electric Operating Revenues" above).

The following table provides a summary of the Utility's cost of electricity and the total amount and average cost of purchased power, excluding, in each case, both the cost and volume of electricity provided by the DWR to the Utility's customers:

(in millions)	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2006	2005	2006	2005
Cost of purchased power	\$ 895	\$ 798	\$ 2,325	\$ 1,827
Proceeds from surplus sales allocated to the Utility	(46)	(98)	(245)	(331)
Fuel used in own generation	35	42	115	130
Total cost of electricity	\$ 884	\$ 742	\$ 2,195	\$ 1,626

Average cost of purchased power per kWh	\$ 0.081	\$ 0.081	\$ 0.079	\$ 0.074
Total purchased power (GWh)	11,037	9,848	29,295	24,779

The Utility's cost of electricity increased by approximately \$142 million, or 19%, in the three months ended September 30, 2006 as compared to the same period in 2005. The cost of purchased power, including hedging costs, increased by approximately \$97 million, or 12%. This increase was primarily due to an increase in the amount of purchased power of approximately 1,189 Gigawatt-hours, or GWh, or 12%. The volume of total purchased power increased due to an increase in customer usage which is partially attributable to the July 2006 heat storm (see further discussion below in "Regulatory Matters - Catastrophic Event Memorandum Account Application") and a decrease in the volume of electricity provided by the DWR to the Utility's customers.

The Utility's cost of electricity increased by approximately \$569 million, or 35%, in the nine months ended September 30, 2006 as compared to the same period in 2005. The cost of purchased power, including hedging costs, increased by approximately \$498 million, or 27%. The increase is due to an increase in the amount of purchased power of approximately 4,516 GWh, or 18%. The volume of total purchased power increased due to an increase in customer usage which is partially attributable to the July 2006 heat storm and a decrease in the volume of electricity provided by the DWR to the Utility's customers. The increase in the volume of purchased power is also due to a 39-day refueling outage at Diablo Canyon during the second quarter of 2006 which required the Utility to purchase higher-cost replacement power, as compared to the first nine months of 2005 when Diablo Canyon was in full operation and no such purchases were required. The average cost of purchased power increased by \$0.005 per kilowatt-hour, or kWh, or 7%.

The Utility's cost of electricity for the remainder of 2006 will depend upon electricity prices and any change in customer usage which will directly impact the Utility's net open position (see the "Risk Management Activities" section in this MD&A). The cost of electricity is also dependent upon weather patterns and seasonality.

The Utility's future cost of electricity also may be affected by potential federal or state legislation or rules which may regulate the emissions of greenhouse gases from the Utility's electric generating facilities or the generating facilities from which the Utility procures power. Currently, pursuant to legislation enacted recently in California, the CPUC is expected to adopt by February 1, 2007 a greenhouse gas emissions performance standard that would apply to electricity procured or generated by the Utility. Additionally, California recently enacted a greenhouse gas emissions law, Assembly Bill 32, which establishes a regulatory program and schedule for establishing a cap on greenhouse gas emissions in the state at 1990 levels effective by 2020, including a cap on the Utility's emissions of greenhouse gases. The Utility's existing and forecast emissions of greenhouse gases are relatively low compared to average emissions by other electric utilities and generators in the country, and the Utility's incremental costs of complying with greenhouse gas emissions regulations being promulgated by the CPUC and other California agencies are expected to be recovered in full in rates from the Utility's customers under the CPUC's ratemaking standards applicable to electricity procurement costs.

Natural Gas Operating Revenues

The Utility sells natural gas and natural gas transportation (transmission and distribution) services to its customers. The Utility's transportation system transports gas throughout California to the Utility's distribution system, which, in turn, delivers gas to end-use customers. The Utility's natural gas customers consist of two categories: core and non-core customers. The core customer class is comprised mainly of residential and smaller commercial natural gas customers. The non-core customer class is comprised of industrial, larger commercial and electric generation natural gas customers. The Utility provides natural gas delivery services to all core and non-core customers connected to the Utility's system in its service territory. Core customers can purchase natural gas from alternate energy service providers or can elect to have the Utility provide both delivery service and natural gas supply.

The Utility's natural gas transmission and storage rates for the 2005 through 2007 period have been determined by a December 2004 CPUC decision which approved the Gas Accord III Settlement Agreement reached among the Utility and other interested parties. Under the Gas Accord III Settlement Agreement, the Utility faces volumetric risk for the portion of intrastate natural gas transmission volumes that are not subscribed for under long-term contracts with fixed reservation charges to core customers or other long-term contract holders. Thus, the Utility assumes the risk of not recovering its full natural gas transmission and storage costs that are not covered by these long-term contracts (see discussion under "Risk Management Activities - Natural Gas Transportation and Storage" in the 2005 Annual Report). The CPUC decision dated December 16, 2004, adopts the Gas Accord III Settlement Agreement that provides that the Utility is required to file its next Gas Transmission and Storage Rate Case no later than February 9, 2007.

The Utility recovers the cost of gas (subject to the ratemaking mechanism discussed below) acquired on behalf of core procurement customers through its retail gas rates. The Utility is protected against after-the-fact reasonableness reviews of these gas procurement costs under an incentive mechanism known as the Core Procurement Incentive Mechanism, or CPIM. Under the CPIM, the Utility's purchase costs for a twelve month period are compared to an aggregate market-based benchmark based on a weighted average of published monthly and daily natural gas price indices at the points where the Utility typically purchases natural gas. The CPIM establishes a "tolerance band" around the benchmark index price, and all costs within the tolerance band are fully recovered from core customers. If total gas costs fall below the tolerance band, PG&E's customers and shareholders will share 75% and 25% of the savings below the tolerance band, respectively. Conversely, if total gas costs rise above the tolerance band, the Utility's core customers and shareholders share equally the costs above the tolerance band. The shareholder award is capped at the lower of 1.5% of total natural gas commodity costs or \$25 million. While this incentive mechanism remains in place, changes in the price of natural gas, consistent with the market-based benchmark, are not expected to materially impact net income.

On October 6, 2005, the CPUC approved the Utility's hedging plan for the winters of 2005-2006, 2006-2007, and 2007-2008. Core customers will pay the cost of these hedges and receive any payouts as these transactions are handled outside of the CPIM. The Utility is at risk to the extent that the CPUC may disallow portions of the hedging cost based on its subsequent review of the Utility's performance under the filed plan. As part of the hedging plan, the Utility also agreed to forego a shareholder award under the CPIM for the 2004-2005 CPIM year.

On August 24, 2006, the CPUC approved the Utility's expanded hedging plan on behalf of core customers to protect them from fuel price spikes this winter. The CPUC decision allows all of the costs and benefits of the expanded winter 2006-2007 hedging plans to be outside of the CPIM.

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

(in millions)	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2006	2005	2006	2005
Bundled natural gas revenues	\$ 615	\$ 640	\$ 2,565	\$ 2,249
Transportation service-only revenues	83	57	221	175
Total natural gas operating revenues	\$ 698	\$ 697	\$ 2,786	\$ 2,424
Average bundled revenue per millions of Mcf of natural gas sold	\$ 17.05	\$ 16.20	\$ 12.72	\$ 10.93
Total bundled natural gas sales (in millions of Mcf)	36	40	202	207

The Utility's natural gas operating revenues increased by approximately \$1 million, or 0.14%, during the three months ended September 30, 2006 compared to the same period in 2005. Bundled natural gas revenues decreased by approximately \$25 million, or 4%, primarily due to an approximate \$55 million decrease in cost of natural gas in the third quarter of 2006, including hedging costs, as further discussed below in "Cost of Natural Gas." This decrease was partially offset by the following:

- Attrition adjustments, as authorized in the 2003 GRC, and revenues authorized in the 2006 cost of capital proceeding increased natural gas operating revenues by approximately \$9 million;
- The Utility recorded approximately \$11 million in natural gas revenues representing a portion of an annual revenue requirement authorized by the CPUC to recover a pension contribution attributable to the Utility's GRC lines of business (see "Regulatory Matters - Defined Benefit Pension Plan Contribution" below); and
- Miscellaneous and other natural gas revenues increased by approximately \$10 million.

In addition, transportation service-only revenues increased by approximately \$26 million, or 46%, primarily as a result of an increase in rates.

The Utility's natural gas operating revenues increased by approximately \$362 million, or 15%, during the nine months ended September 30, 2006 compared to the same period in 2005. The increase in natural gas operating revenues was primarily due to the following factors:

- A \$212 million increase primarily due to an increase in the cost of natural gas (primarily in the first quarter of 2006 compared to the first quarter of 2005), including hedging costs, as further discussed below in “Cost of Natural Gas;”
- Attrition adjustments, as authorized in the 2003 GRC, and revenues authorized in the 2006 cost of capital proceeding increased natural gas operating revenues by approximately \$27 million;
- The Utility recorded approximately \$33 million in natural gas revenues representing a portion of an annual revenue requirement authorized by the CPUC to recover a pension contribution attributable to the Utility’s GRC lines of business (see "Regulatory Matters - Defined Benefit Pension Plan Contribution" below);
- Miscellaneous and other natural gas revenues increased by approximately \$44 million; and
- Transportation service-only revenues increased by approximately \$46 million, or 26%, primarily as a result of an increase in rates.

The Utility's natural gas revenues in 2006 are expected to increase due to an attrition rate increase as authorized in the 2003 GRC decision, revenue requirements associated with recovery of the pension contribution, and an annual rate escalation authorized in the Gas Accord III Settlement, and will be further impacted by changes in the cost of natural gas.

Cost of Natural Gas

The Utility's cost of natural gas includes the purchase cost of natural gas and transportation costs on interstate pipelines, but excludes the costs associated with operating and maintaining the Utility's intrastate pipeline, which are included in operating and maintenance expense.

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

(in millions)	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2006	2005	2006	2005
Cost of natural gas sold	\$ 265	\$ 293	\$ 1,435	\$ 1,189
Cost of natural gas transportation	33	33	104	104
Total cost of natural gas	\$ 298	\$ 326	\$ 1,539	\$ 1,293
Average cost per millions of Mcf of natural gas sold	\$ 7.36	\$ 7.33	\$ 7.10	\$ 5.74
Total natural gas sold (in millions of Mcf)	36	40	202	207

The Utility's total cost of natural gas, including hedging costs, decreased by approximately \$28 million, or 9%, in the three months ended September 30, 2006 as compared to the same period in 2005. This decrease was primarily due to a decrease in the volume of natural gas sold of approximately 4 million Mcf, or 10% (where Mcf is defined as 1,000 cubic feet).

The Utility's total cost of natural gas, including hedging costs, increased by approximately \$246 million, or 19%, in the nine months ended September 30, 2006 as compared to the same period in 2005. This increase was primarily due to an increase in the average price of natural gas purchased, including hedging costs over the nine months ended September 30, 2006 of approximately \$1.36 per millions of Mcf, or 24%.

The Utility recovers the costs of gas (subject to the ratemaking mechanism discussed above in “Natural Gas Operating Revenues” above), acquired on behalf of core procurement customers through its retail gas rates. The Utility's cost of natural gas sold in 2006 will be primarily affected by the prevailing costs of natural gas, which are determined by North American regions that supply the Utility. The cost of gas will also be affected by customer demand.

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. Generally, many of these expenses are offset by corresponding annual revenues authorized by the CPUC and the FERC in various rate proceedings.

During the three months ended September 30, 2006, the Utility's operating and maintenance expenses increased by approximately \$55 million, or 7%, compared to the same period in 2005, mainly due to the following factors:

- An increase of approximately \$35 million primarily due to funding for pension contributions as a result of the CPUC-approved settlement (see "Regulatory Matters - Defined Benefit Pension Plan Contribution" below);
- An increase of approximately \$32 million related to administrative expenses for customer energy efficiency programs and AMI; and
- An increase of approximately \$15 million related to outside consulting, contract expense, and various programs and initiatives, including strategies to achieve operational excellence and improved customer service.

Partially offsetting these increases are the following decreases:

- A decrease of approximately \$12 million in licensing and administrative fees paid to the FERC; and
- A decrease of approximately \$14 million related to lower costs associated with the Utility's Long-Term Disability Plan.

During the nine months ended September 30, 2006, the Utility's operating and maintenance expenses increased by approximately \$458 million, or 21%, compared to the same period in 2005, mainly due to the following factors:

- An increase of approximately \$126 million primarily due to funding for pension contributions as a result of the CPUC-approved settlement (see "Regulatory Matters - Defined Benefit Pension Plan Contribution" below);
- An increase of approximately \$79 million related to administrative expenses for customer energy efficiency programs, low-income customer assistance programs, the Self-Generation Incentive Program and AMI;
- An increase of approximately \$59 million related to salary expenses reflecting increased costs associated with base salaries and incentives;
- An increase of approximately \$40 million reflecting costs associated with the scheduled Diablo Canyon refueling outage in the second quarter of 2006;
- An increase of approximately \$35 million related to outside consulting, contract expense, and various programs and initiatives, including strategies to achieve operational excellence and improved customer service;
- An increase of approximately \$25 million primarily due to an increase in incremental costs attributed to a winter storm during the first quarter of 2006 and the July 2006 heat storm during the third quarter of 2006. The Utility intends to file a 2006 Catastrophic Event Memorandum Account, or CEMA, application with the CPUC on November 13, 2006 for recovery of these costs (see "Regulatory Matters - Catastrophic Event Memorandum Account Application" below); and
- An increase of approximately \$41 million for costs associated with maintaining distribution plant and overhead lines for electric services, franchise fee expense resulting from higher revenues and franchise fee rates, and property taxes due to electric plant growth and higher electric assessments in 2006.

The Utility's operating and maintenance expenses in 2006 are expected to increase as a result of increased expenses related to various programs and initiatives, including public purpose programs and strategies to achieve operational excellence and improved customer service (see the "Overview" section in this MD&A for further discussion). In connection with the Utility's continued effort to streamline processes to achieve cost and operating efficiencies, jobs from numerous locations around California are being consolidated and a number of positions have been eliminated. Impacted employees may elect severance or reassignment. The Utility has already incurred severance costs relating to the positions that have already been eliminated. The Utility expects that more positions will be eliminated through 2007. The Utility estimates that it may incur between \$10 million and \$99 million for future severance expenses that would be included in future operating and maintenance expenses (see further discussion in Note 11 of the Notes to the Condensed Consolidated Financial Statements). 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, and various other administrative and general expenses.

Depreciation, Amortization and Decommissioning

The Utility charges the original cost of retired plant less salvage value to accumulated depreciation upon retirement of plant in service for its lines of business that apply Statement of Financial Accounting Standards, or SFAS, No. 71, "Accounting for the Effects of Certain Types of Regulation," as amended, which includes electricity and natural gas distribution, electricity generation and transmission, and natural gas transportation and storage.

In the three months ended September 30, 2006, the Utility's depreciation, amortization and decommissioning expenses decreased by \$25 million, or 5%, compared to the same period in 2005, primarily as a result of the decrease in amortization of the settlement regulatory asset resulting from the refinancing of the settlement regulatory asset by the issuance of the first series of ERBs. The Utility recorded approximately \$49 million in the three months ended September 30, 2005 for amortization of the settlement regulatory asset, with no similar amount in 2006.

This decrease is partially offset by an increase in the amortization of the ERB regulatory assets of approximately \$30 million. During the third quarter of 2006, the Utility continued to amortize the ERB regulatory assets for the first series of ERBs issued in February 2005, as well as the second series of ERBs issued in November 2005.

In the nine months ended September 30, 2006, the Utility's depreciation, amortization and decommissioning expenses decreased by \$30 million, or 2%, compared to the same period in 2005, primarily as a result of the decrease in amortization of the settlement regulatory asset resulting from the refinancing of the settlement regulatory asset by the issuance of the first series of ERBs. The Utility recorded approximately \$125 million in the nine months ended September 30, 2005 for amortization of the settlement regulatory asset, with no similar amount in 2006. This decrease is partially offset by an increase in the amortization of the ERB regulatory assets by approximately \$118 million. During the first nine months of 2006, the Utility amortized the ERB regulatory assets for the first series of ERBs as well as the second series of ERBs. In addition, the Utility recorded approximately \$23 million in depreciation expense in the nine months ended September 30, 2005 related to recovery of costs as authorized in a December 2004 settlement agreement between the Utility, the CPUC's Division of Ratepayer Advocates, or DRA, Aglet Consumer Alliance, and The Utility Reform Network, or TURN. Under the settlement agreement the Utility was authorized to collect revenue requirements to recover the capital plant costs associated with distribution-related electric industry restructuring costs through rates in 2005. There was no similar depreciation expense in 2006.

In the future, the Utility's depreciation, amortization, and decommissioning expenses are expected to increase as a result of an overall increase in assets due to higher capital expenditures.

Interest Income

In the three months ended September 30, 2006, interest income increased by approximately \$16 million, or 80%, compared to the same period in 2005. In the nine months ended September 30, 2006, interest income increased by approximately \$35 million, or 59%, compared to the same period in 2005. Increases for both periods were a result of the August 31, 2006 FERC decision approving recovery of SC costs, including interest (see "Regulatory Matters - Scheduling Coordinator Costs" below). This increase was partially offset by a decrease in interest earned on short-term investments.

The Utility's interest income during 2006 will be primarily affected by interest rate levels and cash on hand.

Interest Expense

In the three months and nine months ended September 30, 2006, the Utility's interest expense increased by approximately \$6 million, or 4%, and \$31 million or 7% respectively, compared to the same periods in 2005. The increase is primarily due to interest expense associated with the ERBs which was not incurred until after issuance of each series of bonds in 2005, resulting in interest being recorded for only a portion of the nine months in 2005 for the first series of ERBs, as compared to interest being recorded for both the first and second series of ERBs for the nine-month period in 2006. Additionally, a portion of the increase is due to accrual of interest on higher balances in certain revenue balancing accounts as a result of the summer heat storm, combined with an increase in the interest rates associated with these accounts.

The Utility's interest expense in 2006 and subsequent periods will be impacted by changes in interest rates as the Utility's short-term debt and a portion of its long-term debt are interest rate-sensitive. In addition, future interest expense will increase due to higher expected financing resulting from an overall increase in infrastructure investments.

Income Tax Expense

In the three months ended September 30, 2006, the Utility's tax expense increased by approximately \$88 million, or 59%, compared to the same period in 2005, primarily due to the increase in pre-tax income of \$218 million for the three months ended September 30, 2006.

In the nine months ended September 30, 2006, the Utility's tax expense increased by approximately \$52 million, or 11%, compared to the same period in 2005, primarily due to the increase in pre-tax income of \$131 million for the nine months ended September 30, 2006.

PG&E Corporation, Eliminations and Other

Operating Revenues and Expenses

PG&E Corporation's revenues consist mainly of billings to the Utility and its other 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 its affiliates. Operating expenses are allocated to affiliates without mark-up and are eliminated in consolidation. For the three and nine months ended September 30, 2006, there were no material changes to PG&E Corporation's operating income.

Income Tax Benefit

During the third quarter of 2006 PG&E Corporation recorded tax benefits of approximately \$19 million with respect to capital losses carried forward and used in the 2005 federal and state income tax returns.

PG&E Corporation has \$209 million of remaining capital loss carry forwards, which, if not used by December 2009, will expire. These capital losses resulted from PG&E Corporation's disposition of its ownership interest in National Energy and Gas Transmission Inc., or NEGT, in 2004.

LIQUIDITY AND FINANCIAL RESOURCES

Overview

The levels of PG&E Corporation's and the Utility's current assets and current liabilities are subject to fluctuations as a result of seasonal demand for electricity and natural gas, energy commodity costs, and the timing and effect of regulatory decisions and financings, among other factors.

PG&E Corporation and the Utility manage liquidity and debt levels in order to meet expected operating and financial needs and maintain access to credit for contingencies. PG&E Corporation and the Utility intend to manage the Utility's equity level to maintain the Utility's 52% authorized common equity ratio of the Utility's capital structure.

At September 30, 2006, PG&E Corporation and its subsidiaries had consolidated cash and cash equivalents of approximately \$422 million and restricted cash of approximately \$1.5 billion including \$43 million of restricted cash classified as Other Non-Current Assets. PG&E Corporation and the Utility maintain separate bank accounts. At September 30, 2006, PG&E Corporation on a stand-alone basis had cash and cash equivalents of approximately \$354 million; the Utility had cash and cash equivalents of approximately \$68 million and restricted cash of approximately \$1.5 billion including \$43 million of restricted cash classified as Other Non-Current Assets. The Utility's restricted cash includes amounts deposited in

escrow related to the remaining disputed Chapter 11 claims and deposits under certain third-party agreements. PG&E Corporation and the Utility primarily invest their cash in institutional money market funds.

As of September 30, 2006, PG&E Corporation and the Utility had credit facilities totaling \$200 million and \$2 billion, respectively, with remaining borrowing capacity under these credit facilities of \$200 million and \$1.5 billion, respectively. As of September 30, 2006, the Utility had \$222 million of letters of credit outstanding issued under its credit facility. The Utility plans to maintain approximately \$800 million of unused borrowing capacity to provide liquidity in the event of contingencies such as swings in procurement costs and collateral requirements. The Utility eliminated the use of cash as a component of its minimum liquidity reserve in July 2006 and now relies solely on access to the commercial paper market and back-up committed credit lines. In January 2006, the Utility established a \$1 billion commercial paper program. At September 30, 2006, the Utility had \$281 million of outstanding borrowings under the commercial paper program.

During the nine months ended September 30, 2006, the Utility used cash in excess of amounts needed for operations, debt service, capital expenditures, and preferred stock requirements to pay quarterly common stock dividends.

The Utility anticipates that it may issue a material amount of long-term debt primarily to fund capital expenditures for infrastructure improvements depending on whether and when regulatory approval of these capital expenditures is obtained.

Dividends

On February 16, June 22, and September 21, 2006, the Utility paid common stock dividends totaling \$371 million, including \$345 million of common stock dividends paid to PG&E Corporation and \$26 million of common stock dividends paid to PG&E Holdings, LLC, a wholly owned subsidiary of the Utility.

On January 16, April 15, July 15, and October 15, 2006, PG&E Corporation paid common stock dividends of \$0.33 per share, totaling \$488 million, including \$33 million of common stock dividends paid to Elm Power Corporation, a wholly owned subsidiary of PG&E Corporation. PG&E Corporation and the Utility record common stock dividends declared to Reinvested Earnings.

On February 15, May 15, and August 15, 2006, the Utility paid a cash dividend on various series of its preferred stock outstanding totaling \$10 million. On September 20, 2006, the Board of Directors of the Utility declared a cash dividend on various series of its preferred stock payable on November 15, 2006 to shareholders of record on October 31, 2006.

Stock Repurchases

PG&E Corporation has no remaining obligation under the accelerated share repurchase arrangement, or ASR, that it entered into with Goldman Sachs & Co., or GS&Co., in November 2005. For further discussion, see Note 5 of the Notes to the Condensed Consolidated Financial Statements.

Utility

Operating Activities

The Utility's cash flows from operating activities consist of sales to its customers and payments of operating expenses, other than expenses such as depreciation that do not require the use of cash. Cash flows from operating activities are also impacted by collections of accounts receivable and payments of liabilities previously recorded.

The Utility's cash flows from operating activities for the nine months ended September 30, 2006 and 2005 were as follows:

(in millions)	Nine Months Ended September 30,	
	2006	2005
Net income	\$ 826	\$ 747
Non-cash (income) expenses:		

Depreciation, amortization, decommissioning and allowance for equity funds used during construction	1,342	1,294
Deferred income taxes and tax credits, net	(172)	(638)
Other deferred charges and noncurrent liabilities	(65)	(136)
Gain on sale of assets	(15)	-
Change in accounts receivable	239	58
Change in accrued taxes	113	77
Change in regulatory balancing accounts, net	404	940
Other changes in operating assets and liabilities	(561)	(215)
Net cash provided by operating activities	\$ 2,111	\$ 2,127

Net cash provided by operating activities decreased by approximately \$16 million during the nine months ended September 30, 2006 compared to the same period in 2005. During the nine months ended September 30, 2006, the Utility received cash proceeds associated with settlements with energy suppliers in the amount of approximately \$273 million (see Note 11 of the Notes to the Condensed Consolidated Financial Statements for further discussion). Also during this period deferred income taxes and tax credits decreased approximately \$466 million primarily due to an increased California franchise tax deduction and the payment of previously accrued litigation costs.

The above increases were partially offset due to payments of approximately \$290 million for pension contributions during the nine months ended September 30, 2006 (see "Regulatory Matters - Defined Benefit Pension Plan Contribution" below) and due to payments in 2006 of approximately \$320 million for litigation settlements, including the Chromium Litigation settlement agreement. In addition, the Utility's net over-collected position in balancing accounts decreased during the nine months ended September 30, 2006 resulting in less cash received compared to the same period in 2005 (see Note 3 of the Notes to the Condensed Consolidated Financial Statements for further discussion).

In September 2006, the CPUC approved a heat storm credit to help the Utility's customers manage their high electricity bills for energy consumed from July 16 through July 27, 2006 when high temperatures increased electricity demand, and to enable the Utility to return to customers electricity over-collections due to the severe weather on an accelerated basis. The heat storm credit will return 15% and 10% of residential and non-residential customers' respective electricity charges incurred during this period. The Utility has estimated that approximately \$163 million of heat storm credits will be issued, primarily within customers' October bills. As a result, the Utility's cash inflows in the fourth quarter of 2006 will be reduced by the amount of these credits.

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 flows from operating activities have been sufficient to fund the Utility's capital expenditure requirements during the nine months ended September 30, 2006 and 2005. Year-to-year variances depend upon the amount and type of construction activities, which can be influenced by storms and other factors.

The Utility's cash flows from investing activities for the nine months ended September 30, 2006 and 2005 were as follows:

(in millions)	Nine Months Ended	
	September 30,	
	2006	2005
Capital expenditures	\$ (1,729)	\$ (1,318)
Net proceeds from sale of assets	11	19
Decrease in restricted cash	58	453
Proceeds from nuclear decommissioning trust sales	942	2,428
Purchases of nuclear decommissioning trust investments	(1,040)	(2,492)
Other investing activities, net	-	67
Net cash used in investing activities	\$ (1,758)	\$ (843)

Net cash used by investing activities increased by approximately \$915 million primarily due to an increase in capital expenditures of approximately \$411 million for the nine months ended September 30, 2006. The Utility estimates that during the fourth quarter of 2006 it will invest an additional approximately \$770 million in plant and equipment (see the “Capital Expenditures” section below for further discussion). In addition, the decrease in restricted cash was approximately \$395 million greater in the nine months ended September 30, 2005 than in the same period in 2006. This decrease was primarily a result of cash released from escrow as a result of more supplier settlements in 2005 as compared to 2006.

Financing Activities

The Utility's cash flows from financing activities for the nine months ended September 30, 2006 and 2005 were as follows:

(in millions)	Nine Months Ended September 30,	
	2006	2005
Borrowings under accounts receivable facility	\$ 50	\$ -
Repayments under working capital facility and accounts receivable facility	(310)	(300)
Borrowings under commercial paper facility, net	281	-
Proceeds from issuance of long-term debt	-	451
Net proceeds from energy recovery bonds issued	-	1,874
Long-term debt, matured, redeemed or repurchased	(1)	(1,554)
Rate reduction bonds matured	(214)	(214)
Energy recovery bonds matured	(224)	(77)
Common stock dividends paid	(345)	(330)
Preferred stock dividends paid	(10)	(12)
Preferred stock with mandatory redemption provisions redeemed	-	(122)
Preferred stock without mandatory redemption provisions redeemed	-	(36)
Common stock repurchased	-	(960)
Other	25	69
Net cash used in financing activities	\$ (748)	\$ (1,211)

For the nine months ended September 30, 2006, net cash used in financing activities decreased by approximately \$463 million compared to the same period in 2005, primarily due to the following factors:

- In May 2005, the Utility entered into seven loan agreements with the California Infrastructure and Economic Development Bank under which the Utility borrowed \$451 million funded by the bank's issuance of Pollution Control Bonds Series A-G, with no similar borrowing in 2006;
- In February 2005, PERF issued approximately \$1.9 billion of ERBs, with no similar issuance in 2006. In March 2005, the Utility used proceeds from the issuance of ERBs to repurchase \$960 million of its common stock from PG&E Corporation, with no similar repurchase in 2006;
- Approximately \$224 million of ERBs matured in the first three quarters of 2006, with no similar maturities in the first quarter of 2005 and only \$77 million of maturities in the second and third quarter of 2005;
- During the nine months ended September 30, 2005, the Utility fully redeemed \$122 million of preferred stock with mandatory redemption provisions, with no similar redemption in 2006;

- In January 2005, the Utility partially redeemed Floating Rate First Mortgage Bonds due in 2006 in the aggregate principal amount of \$300 million, and in February 2005, the Utility used a portion of the ERB proceeds to defease \$600 million of Floating Rate First Mortgage Bonds. In April 2005, the Utility repaid \$454 million under certain reimbursement obligations that the Utility entered into in April 2004, when its plan of reorganization under Chapter 11 became effective. On July 3, 2005, the remaining \$200 million of Floating Rate First Mortgage Bonds were redeemed. There were no similar redemptions and repayments in 2006; and
- The Utility had net borrowings of \$281 million of commercial paper, with no similar amount in 2005.

PG&E Corporation

As of September 30, 2006, PG&E Corporation had stand-alone cash and cash equivalents of approximately \$354 million. PG&E Corporation's sources of funds are dividends and share repurchases from the Utility, issuance of its common stock, and external financing.

Operating Activities

PG&E Corporation's consolidated cash flows from operating activities consist mainly of billings to the Utility and other affiliates 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, had a net increase in cash provided by operating activities of approximately \$129 million for the nine months ended September 30, 2006. This increase was primarily due to tax refunds received during the first and third quarters of 2006, with no similar refunds received during 2005. On a stand alone basis, PG&E Corporation did not have any material operating activities for the nine months ended September 30, 2005.

Investing Activities

PG&E Corporation, on a stand-alone basis, did not have any material investing activities for the nine months ended September 30, 2006 and 2005.

Financing Activities

PG&E Corporation's consolidated cash flows from financing activities consist mainly of cash generated from debt financing, issuance of common stock, and the payment of dividends.

PG&E Corporation's consolidated cash flows from financing activities for the nine months ended September 30, 2006 and 2005 were as follows:

(in millions)	Nine Months Ended	
	September 30,	
	2006	2005
Borrowings under accounts receivable facility	\$ 50	\$ -
Repayments under working capital facility and accounts receivable facility	(310)	(300)
Borrowings under commercial paper facility, net	281	-
Proceeds from issuance of long-term debt	-	451
Net proceeds from issuance of energy recovery bonds	-	1,874
Long-term debt matured, redeemed or repurchased	(1)	(1,556)
Rate reduction bonds matured	(214)	(214)
Energy recovery bonds matured	(224)	(77)
Preferred stock with mandatory redemption provisions redeemed	-	(122)
Preferred stock without mandatory redemption provisions redeemed	-	(36)
Common stock issued	108	231
Common stock repurchased	(114)	(1,087)
Common stock dividends paid	(342)	(223)
Other	(7)	46
Net cash used by financing activities	\$ (773)	\$ (1,013)

For the nine months ended September 30, 2006, PG&E Corporation's consolidated net cash used by financing activities decreased by approximately \$240 million, compared to the same period in 2005, primarily due to the following factors, after consideration of the Utility's cash flows from financing activities:

- In 2006, PG&E Corporation paid approximately \$342 million in common stock dividends related to the fourth quarter of 2005 and the first and second quarters of 2006. In comparison, PG&E Corporation's payment of common stock dividends in 2005 related only to the first and second quarters of 2005; and
- In March 2005, PG&E Corporation paid approximately \$1.1 billion to repurchase approximately 29.5 million shares of its common stock under an ASR arrangement. (The Utility's repurchase of its common stock from PG&E Corporation totaling \$960 million in March 2005 was eliminated in consolidation.) There was no similar share repurchase in 2006; however, PG&E Corporation paid certain additional payments of approximately \$114 million to GS&Co., as required under the share forward agreement related to the November 2005 ASR.

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. Refer to Notes 4 and 11 in the Notes to the Condensed Consolidated Financial Statements and the 2005 Annual Report for further discussion.

Utility

The Utility's contractual commitments include power purchase agreements (including agreements with QFs, irrigation districts and water agencies, and renewable energy providers), natural gas supply and transportation agreements, nuclear fuel agreements, operating leases, and other commitments (see the section entitled "Regulatory Matters - Electricity Generation Resources" below for a discussion of new power purchase agreements into which the Utility has entered and which the Utility has submitted to the CPUC for approval).

CAPITAL EXPENDITURES

The Utility estimates that in 2006 it will invest \$2.5 billion in plant and equipment, resulting in a projected weighted average rate base of \$15.9 billion for the year ended December 31, 2006. For the nine months ended September 30, 2006, the Utility has incurred capital expenditures of approximately \$1.7 billion and expects to incur approximately \$770 million through the end of the year. Over the next four years (2007 through 2010), the Utility expects to incur capital expenditures relating to investments to implement AMI, the acquisition and development of Contra Costa Unit 8, and, subject to regulatory approval, infrastructure improvements. In addition, the Utility may incur capital expenditures related to potential investments associated with new generation resources that have not yet been approved by the CPUC, as discussed below under "Regulatory Matters - Electricity Generation Resources ."

Advanced Metering Infrastructure

On July 20, 2006, the CPUC issued a decision approving the Utility's application to install an AMI for virtually all of the Utility's electric and gas customers. The Utility has begun installing the network infrastructure required for the meter data collection and expects to begin installing the advanced meters during the fourth quarter of 2006. The Utility expects to complete the installation of the network infrastructure and advanced meters throughout its service territory by the end of 2011.

The CPUC authorized the Utility to recover the \$1.74 billion estimated AMI project cost, including an estimated capital cost of \$1.4 billion. The \$1.74 billion amount includes \$1.68 billion for project costs and approximately \$54.8 million for costs related to marketing the new critical peak pricing rate option described below. In addition, the Utility is authorized to recover in rates 90% of up to \$100 million in costs that exceed \$1.68 billion without a reasonableness review. The remaining 10% will not be recoverable in rates. If additional costs exceed the \$100 million threshold, the Utility may request recovery of the additional costs, subject to a reasonableness review.

The CPUC also approved the Utility's proposal to offer customers a new voluntary billing option called critical peak pricing, or CPP, under which customers will be able to take advantage of electricity prices that vary by day and hour, potentially reducing their bills by shifting their energy use away from critical peak periods. By shifting energy demand away from critical peak periods, the Utility anticipates that it would need to purchase less power for critical peak periods.

The DRA filed an application for rehearing of the CPUC's decision approving the implementation of the AMI project based on their assessment of the CPP program for residential customers. On October 19, 2006, the CPUC denied their request for rehearing.

The Utility has established separate electric and gas balancing accounts to record the revenue requirements associated with the costs and forecast benefits related to AMI. The Utility will record the revenue requirement as costs are incurred over the installation period. As new meters are activated, the Utility will record the amount of the forecasted electric and gas operational benefits per meter. The CPUC accepted the Utility's forecast of electric and gas operational benefits to be achieved by AMI. These ratemaking mechanisms will remain in place at least until the Utility's next general rate case, expected to occur for test year 2010 or later.

PG&E Corporation and the Utility cannot guarantee the extent to which the anticipated benefits and cost savings of the AMI project will be realized.

Diablo Canyon Steam Generator Replacement Project

In November 2005, the CPUC approved the Utility's steam generator replacement project, or SGRP, to replace the steam generators at the two nuclear operating units at Diablo Canyon. The Utility plans to replace Unit 2 steam generators in 2008 and replace Unit 1 steam generators in 2009. Because the fabrication of new steam generators requires a long lead time, in August 2004, the Utility entered into contracts with Westinghouse Electric Company LLC, or Westinghouse, for the design, fabrication, and delivery of eight steam generators. Under the contracts, the Utility must pay Westinghouse for all work done and a pro-rated profit up to the time the performance under the contracts is completed or the contracts are terminated. The contracts require progress payments in line with actual expenditures for materials and work completed over the life of the contracts.

As of September 30, 2006, the Utility had incurred approximately \$127 million in connection with the SGRP under various construction and installation contracts that the Utility has executed. Based on updated estimates of the cost to complete the SGRP, the Utility estimates that it will spend an additional \$501 million to complete the SGRP through 2010.

To implement the SGRP, the Utility requires two permits from San Luis Obispo County: a conditional use permit to store the old generators on site at Diablo Canyon and a coastal development permit to build temporary structures at Diablo Canyon to house the new generators as they are prepared for installation. At a public hearing on January 12, 2006, the San Luis Obispo County Planning Commission denied approval of both permits. The Utility appealed the denials to the Board of Supervisors of San Luis Obispo County at a public hearing on March 7, 2006 and both permits were approved. On March 20, 2006, the Mothers for Peace, along with the Santa Lucia Chapter of the Sierra Club, appealed the Board of Supervisors' approval of both permits to the California Coastal Commission, or Coastal Commission. The Utility expects that the Coastal Commission will issue a decision on the appeal by the end of 2006. If the Utility's SGRP is delayed, the Utility could incur additional costs to operate and maintain the old steam generators until they can be replaced. If the Utility is ultimately unable to replace the steam generators, the Utility would be required to cease operations at Diablo Canyon and procure power from other sources when the generators are no longer operable in conformance with operating standards.

Contra Costa Unit 8

In January 2005, the Utility and other parties entered into a settlement agreement with Mirant Corporation and certain of its subsidiaries, or Mirant, related to claims outstanding in Mirant's Chapter 11 proceeding. Under the settlement agreement, Mirant agreed to transfer to the Utility the equipment, permits, and contracts for the construction of Contra Costa Unit 8, a modern 530-MW electric generating facility that Mirant had started to build, but never completed. On June 10, 2005, the Utility and Mirant completed negotiations of an Asset Transfer Agreement, which provides the terms and conditions under which the Contra Costa Unit 8 equipment, permits, and contracts would be transferred to the Utility and development and construction of the plant would be completed. On June 17, 2005, the Utility filed an application with the CPUC requesting approval of the Asset Transfer Agreement and cost-of-service funding to complete the construction of the facility, and funding to operate it for up to three years. On June 13, 2006, the FERC authorized Mirant to transfer Contra Costa Unit 8 to the Utility. On June 15, 2006, the CPUC approved the Utility's application to acquire Contra Costa Unit 8, to complete construction at a cost of approximately \$300 million, and to operate the facility. The completion of the acquisition

remains subject to the satisfaction of a number of closing conditions. Refer to Note 11 in the Notes to the Condensed Consolidated Financial Statements for further discussion.

As a result of changes to Contra Costa Unit 8's environmental permits, as of September 30, 2006, approximately \$75 million of additional expenditures are necessary to convert the plant from fresh water cooling to dry cooling. The Utility plans to make an advice filing with the CPUC on November 8, 2006 requesting approval to recover these additional expenditures.

OFF-BALANCE SHEET ARRANGEMENTS

For financing and other business purposes, PG&E Corporation and the Utility utilize 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's or the Utility's activities or a significant ongoing source of financing. These arrangements are used to enable PG&E Corporation or the Utility to obtain financing or execute commercial transactions on favorable terms, and amounts due under these contracts are contingent upon terms contained in these arrangements. For further information related to letter of credit agreements, credit facilities, pollution control bond insurance and bank reimbursement agreements, and PG&E Corporation's guarantee related to certain NEGT indemnity obligations, see the 2005 Annual Report and Notes 4, 5, and 11 of the Notes to the Condensed Consolidated Financial Statements.

CONTINGENCIES

PG&E Corporation and the Utility have significant contingencies that are discussed below. Also, refer to Note 11 in the Notes to the Condensed Consolidated Financial Statements for further discussion.

REGULATORY MATTERS

This section of the MD&A discusses developments that have occurred in significant regulatory proceedings presented in the 2005 Annual Report and significant new regulatory proceedings that have been initiated since the 2005 Annual Report was filed with the SEC.

2007 General Rate Case

On August 21, 2006, the Utility, together with the DRA, various irrigation districts, the Western Manufactured Housing Communities Association, the Disability Rights Advocates, the California Farm Bureau Federation, Southern California Edison, Southern California Gas Company, San Diego Gas & Electric Company, and the Coalition of California Utility Employees, filed a motion with the CPUC seeking approval of a settlement agreement reached among the parties to resolve all of the issues raised by these parties and all revenue requirement related issues raised by other parties in the Utility's 2007 GRC proceeding. The settlement agreement proposes to set the Utility's revenue requirements for a four-year period, 2007-2010, rather than for a typical three-year period. Under this proposal, the Utility's next GRC would be effective January 1, 2011. As further discussed below, the settlement agreement includes a provision for attrition adjustments to be made to authorized revenues in 2008, 2009 and 2010. On October 5, 2006, the Utility filed its responses to the protests filed by TURN, Aglet Consumer Alliance, and the Alliance for Nuclear Responsibility, together with the Sierra Club, to the proposed settlement agreement.

The settlement agreement proposes that the Utility's electric and gas service revenue requirements effective January 1, 2007 be set at approximately \$2.9 billion for electric distribution, approximately \$1 billion for gas distribution, and \$1 billion for electric generation operations, for a total of approximately \$5 billion. The settlement agreement also provides for an attrition adjustment to authorized revenues of \$125 million in 2008 and 2009. In addition, the Utility would receive a one-time additional amount of \$35 million in 2009 for a planned second refueling at Diablo Canyon. The attrition adjustment to authorized revenues for 2010 would be \$125 million, less the one-time additional amount of \$35 million from 2009, for a net increase of \$90 million in 2010. The Utility's customers will receive the benefit of cost savings attributable to the Utility's implementation of initiatives to achieve operating and cost efficiencies in 2008, 2009 and 2010 associated with the attrition adjustments discussed above. If the actual cost savings exceed these amounts, such benefits would accrue to shareholders. Conversely, if these cost savings are not realized, earnings available for shareholders would be reduced.

The Utility projects that the amount of revenue requirements provided in the settlement agreement would enable the Utility to make needed improvements in its electric and gas distribution system infrastructure and in its existing electric generation business as planned over the 2007-2010 time period.

On October 19, 2006, the CPUC approved the Utility's request to make the revenue requirements ultimately adopted by the CPUC in the GRC effective on January 1, 2007. The CPUC noted that delays in the proceeding schedule caused by the parties' good-faith settlement negotiations made it unlikely that the CPUC would issue a final decision before January 1, 2007.

PG&E Corporation and the Utility are unable to predict whether the settlement agreement will be approved by the CPUC.

Electricity Generation Resources

California legislation allows the California investor-owned utilities to recover their reasonably incurred wholesale electricity procurement costs. The legislation's mandatory rate adjustment provision requiring the CPUC to adjust retail electricity rates or order refunds, as appropriate, when the forecast aggregate over-collections or under-collections exceed 5% of a utility's prior year electricity procurement revenues (excluding amounts collected for the DWR contracts) expired on January 1, 2006. In December 2004, in approving the California investor-owned utilities' long-term procurement plans, the CPUC decided that it would continue the mandatory rate adjustment mechanism for the length of a utility's resource commitment or 10 years, whichever is longer.

The Utility executed power purchase agreements to secure new generation resources in accordance with the Utility's long-term electricity procurement plan, to meet the Utility's resource adequacy requirement, and to meet the Utility's renewable energy requirements. In addition, the Utility has executed agreements for new Utility-owned generation resources that remain subject to CPUC approval, as discussed below.

Cost Recovery for New Generation Resources

The authorized revenue requirements for capital costs and non-fuel operating and maintenance costs for Utility-owned generation are addressed in the Utility's general rate case which generally occurs every three years. If the GRC settlement discussed above is approved by the CPUC, the Utility's next general rate case will not occur until 2011. The Utility has filed an application with the CPUC to approve new long-term generation resource commitments and establish the initial capital costs for two proposed Utility-owned generation projects, as discussed below. If approved by the CPUC, these initial capital costs will be trued-up with actual costs in the next general rate case. The Utility's forecasted costs under power purchase agreements and fuel costs are reviewed annually and recovered through the Energy Resource Recovery Account, or the ERRA, a balancing account designed to track and allow recovery of the difference between the authorized revenue requirement and actual costs incurred under the Utility's authorized procurement plans.

As to the recovery on any above-market or "stranded" costs, in the December 2004 CPUC decision approving the California investor-owned utilities' long-term procurement plans, the CPUC decided that the utilities should be allowed to recover any stranded costs through a non-bypassable charge to be collected from departing customers, as well as from their retail or "bundled" electricity customers. The CPUC decided that the non-bypassable charge on departing customers could be imposed from the date of signing a power purchase agreement or the date of commercial operation of a utility-owned power plant. For a utility-owned plant, the duration of the non-bypassable charge would be 10 years, and for a power purchase agreement the duration would be 10 years or the term of the contract, whichever is less. The CPUC also decided that the utilities should be allowed to justify a cost recovery period longer than 10 years on a case-by-case basis. In addition, the California legislature has added Assembly Bill 380 to the Public Utilities Code, allowing the CPUC to authorize a non-bypassable charge under certain conditions, without specifying an end date.

In July 2006, the CPUC issued a decision designating the California investor-owned utilities as responsible for procuring new generation in California. For new generation purchased from third parties under power purchase agreements, the utilities may elect to allocate the net capacity costs (i.e., contract price less energy revenues) to all "benefiting customers" in the utilities' service territory, including direct access customers and community choice aggregation customers, rather than recovering costs only from their bundled and departing customers. If a utility elects to use this cost allocation method, the net capacity costs would be allocated for the term of the contract or 10 years, whichever is less, starting on the date the new generation unit comes on line. If a utility elects to use this cost allocation mechanism, it must use a third-party independent evaluator to oversee the competitive request for offers, or RFO, that produces a contract subject to this cost allocation mechanism. Once the contract is selected through the RFO an independent evaluator must then administer an auction for the energy rights to the contract to minimize the net capacity costs that would be subject to allocation. If no bids are accepted for the energy rights, the utility would retain the rights to the energy and would value it at spot market prices for the purposes of

determining the net capacity costs to be allocated until the next periodic auction. Specific implementation details for the energy rights auction will be addressed in the utilities' long-term procurement plans, to be submitted later this year.

The utilities' owned generation resource costs would not be eligible for recovery under this cost allocation mechanism. As discussed above, these costs would only be eligible for recovery from the utilities' bundled electricity customers and through a non-bypassable charge imposed on departing customers.

New Long-Term Generation Resource Commitments

On October 17, 2006, a proposed decision was issued by a CPUC administrative law judge that recommends the approval of the seven agreements the Utility submitted to the CPUC in April 2006 that would provide 2,250 MW of new long-term electricity generation resources in Northern California in accordance with the Utility's 2004-2014 long-term electricity procurement plan. It is expected that the CPUC will issue a final decision by the end of 2006.

Utility-Owned Projects. Two of the agreements provide for third party developers to construct generation facilities to be owned and operated by the Utility. One of these contracts calls for the construction of a 657-MW power plant to be located in Colusa, California. The other contract calls for the construction of a 163-MW power plant at the Utility's Humboldt Bay facility to replace the existing power plant at Humboldt Bay, which is at the end of its useful life. As to these contracts, the proposed decision recommends the adoption of an initial capital cost equal to the sum of the fixed contract costs plus the Utility's estimated owner's costs. The initial capital costs for these two plants are filed with the CPUC under confidentiality provisions, but are consistent with the Utility's estimated capital costs range from \$900 to \$1,100 per kilowatt. The proposed decision recommends the rejection of the Utility's request to include potential incentive payments to the contractor and contingency amounts that may be incurred by the Utility in connection with unforeseen events in the authorized initial capital costs. Instead, the Utility would be authorized to adjust the initial capital cost to reflect any actual incentive payments paid under the contracts through notification to the CPUC but without a reasonableness review. The Utility's request to recover other additional capital costs would be subject to a reasonableness review.

The proposed decision's findings regarding initial capital costs differ from the CPUC's December 2004 decision that capped cost recovery for construction of utility-owned generation resources at their final bid price and required the utilities to share any construction cost savings with customers while absorbing the full amount of any cost overruns. (In December 2005, the CPUC had indicated that it would revisit its determination regarding the "cost cap" and the sharing of construction cost savings in 2006). The proposed decision recommends the rejection of the Utility's request to permit recovery of the above-market costs of the new projects through a non-bypassable charge to be imposed on departing customers for the 30-year life of the project. Instead the proposed decision finds that the 10-year cost recovery period would apply. At the end of this 10-year period, the Utility would still be able to collect any above-market costs from its bundled customers, but will no longer be able to charge departing customers for these costs.

In addition, the proposed decision recommends the adoption of the Utility's estimates of non-fuel operations and maintenance costs for the purpose of establishing an initial revenue requirement for the two Utility-owned generation projects. The proposed decision does not accept the Utility's proposal to include contingency amounts in the authorized revenue requirements for operating and maintenance expense. Instead, the proposed decision suggests that the Utility be authorized to adjust the initial revenue requirement through notification to the CPUC for changes to its expense forecast that may occur as a result of (1) increased staffing levels due to permitting requirements, or (2) a change in the commercial operation date. The proposed decision recommends that the Utility's requested expense contingency amounts be placed in a one-way balancing account, which the Utility may recover if and when they are actually expended. The proposed decision notes that a one-way balancing account is appropriate because the new plants may not become operational until after the Utility's next general rate case and the Utility should not have to wait to recover these costs until after they have been reviewed in the next general rate case.

The proposed decision notes that the revenue requirement to recover the initial capital costs for the Colusa project will begin to accrue in the Utility Generation Balancing Account, or UGBA, as of the date the completed plant is transferred to the Utility, and would be included in rates on January 1 of the following year. The initial revenue requirement for the Humboldt Bay project would begin to accrue in the UGBA as of its commercial operation date, and would be included in rates on January 1 of the following year.

In addition, as discussed in Note 11 of the Notes to the Condensed Consolidated Financial Statements, pursuant to the Utility's settlement with Mirant on June 15, 2006, the CPUC approved the Utility's agreement with Mirant to acquire and

complete the Contra Costa Unit 8 subject to certain conditions. In approving the Contra Costa Unit 8 acquisition, the CPUC authorized the Utility to collect a non-bypassable charge over 10 years, rather than over 30 years as requested by the Utility.

Power Purchase Agreements. The October 17, 2006 proposed decision also recommends the approval of five power purchase agreements. The Utility has executed four of these agreements that would provide approximately 800 MW of capacity with terms from 15 to 20 years. The Utility has entered into a letter of intent with an affiliate of Calpine Corporation that provides that the parties would execute the fifth power purchase agreement to provide 601 MW of capacity over a 10-year term if the CPUC approves the agreement and if certain other conditions, including that the associated Calpine Corporation affiliate emerges from bankruptcy or transfers the project assets to a non-bankrupt special purpose entity, are met. The Utility cannot predict whether these conditions will be satisfied or whether the parties will execute a power purchase agreement.

The proposed decision recommends that the Utility be authorized to recover the fixed and variable costs of the power purchase agreements, along with fuel costs, through the ERRA for the terms of the agreements. The proposed decision permits the Utility to defer its election of a cost allocation method for the power purchase agreements until after a final decision is issued determining the rules for the energy rights action (discussed above under “Cost Recovery for New Generation Resources”) or until further direction by the CPUC. If the CPUC approves the agreements and if permitting and construction schedules are met, the new generation facilities are anticipated to begin delivering power to the grid during 2009 through 2010.

The Utility’s 2004 long-term procurement plan indicates that the Utility has a long-term generation resource need for up to 2,200 MW of capacity through 2010, based on certain assumptions. Including Contra Costa Unit 8, the Utility has requested the CPUC to approve long-term resources that together exceed the 2,200 MW forecast included in the Utility’s long-term procurement plan due to uncertainties regarding the permitting and construction schedules of the proposed resource additions, whether the proposed power purchase agreement subject to the letter of intent discussed above is executed, the retirement of existing aging power plants, and the rate of future load growth. The Utility has requested that the CPUC authorize all of the proposed resource additions to maintain a reliable source of generation supplies in northern California.

Resource Adequacy

Each year California investor-owned electric utilities (and certain other entities that serve electricity customers) are required to achieve an electricity planning reserve margin of 15% to 17% in excess of forecasted peak electricity usage or “load.” In October 2005, the CPUC issued a decision that requires the utilities and other entities to file annual and monthly reports to demonstrate that they have obtained sufficient quantities of capacity to meet their general or “system” resource adequacy requirements (i.e., resources that are deliverable anywhere in the ISO-controlled electricity grid). In June 2006, the CPUC also adopted “local” resource adequacy requirements to set local capacity requirements in specific regions that may be transmission-constrained. Future phases of the CPUC’s resource adequacy proceeding are expected to address review of the current program, refinement of the rules, and a longer-term program framework. The longer-term program framework may include a centralized capacity market that would allow procurement through the market in addition to bilateral agreements and utility-owned resources.

If the CPUC determines that a utility or other load serving entity has not met its requirement in a particular year, the CPUC can impose penalties in an amount determined by the CPUC. The penalty for failure to procure sufficient system resource adequacy capacity is equal to three times the cost of securing new resources, which the CPUC set at \$120 per kilowatt-year, or kW-year (three times \$40 per kW-year); however, for 2006 the penalty is set at one-half of the amount (i.e., \$60 per kW-year). The penalty for failure to meet local resource adequacy requirements is equal to \$40 per kW-year. In addition to penalties, entities that fail to meet resource adequacy requirements may be assessed the cost of backstop procurement by the ISO to fulfill their resource adequacy target levels. The Utility’s CPUC-approved 2004-2014 long-term procurement plan forecasts that the Utility will be able to meet future resource adequacy requirements.

Renewable Energy Contracts

California law, as amended on September 26, 2006 by the enactment of Senate Bill 107, established the Renewables Portfolio Standard Program, or RPS, which requires each California retail seller of electricity, except municipal utilities, to increase its purchases of eligible renewable energy (such as biomass, small hydro, wind, solar, and geothermal energy) by at least 1% of its retail sales per year, the annual procurement target, so that the amount of electricity purchased from eligible renewable resources equals at least 20% of its total retail sales by the end of 2010. The CPUC has been applying “flexible

compliance” rules to determine whether a retail seller has met its annual procurement target. These rules allow a retail seller to satisfy and defer (for up to three years) its current year RPS requirements by signing contracts with renewable energy suppliers for future deliveries of renewable power. These rules also allow the CPUC to excuse noncompliance with the RPS targets if a retail seller is able to demonstrate good cause. Senate Bill 107, which becomes effective January 1, 2007, continues to permit use of flexible compliance rules and directs the CPUC to adopt flexible compliance rules that will apply to all years, including years before and after a retail seller meets the 20% RPS target. Senate Bill 107 also excuses retail sellers from the 20% RPS requirement if there is insufficient transmission capacity to bring that power into their system.

On October 19, 2006, the CPUC adopted rules for reporting and determining whether the RPS requirements have been met. The CPUC’s decision confirms that the existing flexible compliance rules apply to procurement through 2009, allowing an excused 2009 deficit to be fulfilled by the end of 2012. The CPUC also stated that the 20% RPS target must be met with actual eligible renewable energy deliveries in 2010, subject to further order. The CPUC also stated that a retail seller that has reached the 20% RPS target in a given year is excused from increasing its procurement the next year (or subsequent years) only if it has met its annual procurement target in each of the prior years, or is otherwise excused by the CPUC. The CPUC stated that it will address whether flexible compliance rules apply in 2010 and beyond in a future decision.

Failure to satisfy the annual requirement after application of the flexible compliance rules may result in a penalty of five cents per kWh, with an annual penalty cap of \$25 million. The exact amount of any penalty and the conditions under which it would be applied are subject to the CPUC’s review of the reasonableness of the utilities’ efforts to meet the requirement. In addition to construction and development risks, whether renewable energy from new generation facilities can be timely delivered is subject to electric transmission constraints.

Currently, power from eligible renewable energy resources comprises approximately 12% of the Utility’s retail sales. The Utility expects to comply with its 2004, 2005, 2006 and 2007 annual RPS targets. Although the Utility expects it will achieve the 20% target using the flexible compliance rules by 2010, actual deliveries of renewable power may not comprise 20% of its bundled retail sales by 2010 due to such factors as the time required for the construction of new generation facilities and/or needed transmission capacity. As discussed above, failure to satisfy the RPS targets may result in a penalty of five cents per kWh, with an annual penalty cap of \$25 million. Subject to the CPUC’s future rulemaking to conform its flexible compliance rules to Senate Bill 107’s requirement that the CPUC’s flexible compliance rules apply in all years, the Utility does not expect it would incur any penalties.

The CPUC has adopted a procedure to enable the utilities to recover the cost of electric transmission and distribution facilities necessary to interconnect renewable energy resources if those costs cannot be recovered in federally approved rates. In 2006, the Utility will continue to plan for and begin implementation of various transmission projects to improve access to renewable energy resources, among other purposes.

Qualifying Facility Power Purchase Agreements

The CPUC is considering various policy and pricing issues related to power purchased from QFs in several rulemaking proceedings. It is expected that a proposed decision addressing those issues will be issued soon. In April 2006, the Utility and the Independent Energy Producers on behalf of certain QFs entered into a settlement agreement to resolve these issues irrespective of how the CPUC ultimately resolves these issues. These remain unresolved for the QFs that did not accept the terms of the settlement agreement. On July 20, 2006, the CPUC approved the settlement agreement and amendments relating to QFs which became effective once the CPUC decision became final and non-appealable on August 21, 2006. As of September 30, 2006, 122 QFs are subject to an amendment of their existing contracts with the Utility to reduce the Utility’s energy payments and to establish a new five-year fixed pricing option for non-natural gas-fired QFs. The settlement agreement also resolves certain energy crisis claims among the Utility and the settling QFs that are pending in another CPUC proceeding. As described in Note 11 in the Notes to the Condensed Consolidated Financial Statements, the obligations under many of the amended QF contracts must be accounted for as capital lease obligations. When a final decision addressing these issues is issued by the CPUC, the Utility will re-evaluate the accounting treatment for QF contracts that are affected by the decision.

FERC Transmission Rate Cases

The Utility’s electric transmission revenues and wholesale and retail transmission rates are subject to authorization by the FERC. In August 2005, the Utility filed an application with the FERC requesting an annual retail network transmission revenue requirement of approximately \$654 million. On May 19, 2006, the FERC approved a settlement that provides the Utility an annual transmission revenue requirement of \$606 million, an increase of approximately \$87 million.

over previously authorized retail transmission rates, effective March 1, 2006.

On August 1, 2006, the Utility filed an application with the FERC requesting an annual transmission revenue requirement of approximately \$719 million, effective October 1, 2006. The proposed rates represent an increase of approximately \$113 million over current authorized rates. On September 29, 2006, the FERC issued an order accepting the Utility's rate application, suspending the requested rate changes for five months to become effective March 1, 2007, subject to refund. The FERC also ordered the parties to engage in settlement discussions to be supervised by a settlement judge and ordered that hearings be held if a settlement agreement is not reached.

PG&E Corporation and the Utility are unable to predict what amount of revenue requirements the FERC will authorize, when a final decision will be received from the FERC, or the impact that it will have on their results of operations.

Scheduling Coordinator Costs

Before the ISO commenced operation in 1998, the Utility had entered into several wholesale electric transmission contracts with various governmental entities. After the ISO began operations, the Utility served as the SC with the ISO for these existing wholesale transmission customers, or ETCs. The ISO billed the Utility for providing certain services associated with this scheduling. These ISO charges are referred to as "SC costs." The SC costs were initially tracked in the TRBA in order to recover the SC costs from retail and new wholesale transmission customers, or TO Tariff customers.

In 1999, a FERC administrative law judge, or ALJ, ruled that the Utility could not recover the SC costs through the TRBA and instead should seek to recover the SC Costs from the ETCs. The Utility appealed this ruling. In January 2000, the FERC accepted a filing by the Utility to establish the Scheduling Coordinator Services, or SCS, Tariff, to serve as an alternative mechanism for recovery of the SC costs from the ETCs in case the Utility's appeal was unsuccessful and the Utility was ultimately unable to recover these costs in the TRBA. In August 2002, the FERC affirmed the ALJ's 1999 ruling that the Utility should refund to TO Tariff customers the SC costs that the Utility had collected through the TRBA. In the absence of an order from the FERC granting recovery of these costs through the TRBA, the Utility removed the SC costs from the TRBA and reflected the SC costs as accounts receivable under the SCS Tariff. The Utility appealed the FERC's decision to the U.S. Court of Appeals for the District of Columbia Circuit, or D.C. Circuit. In June 2004, the Utility began billing the ETCs under the SCS Tariff for SC charges retroactive to April 1, 1998. In the course of the SCS Tariff proceeding at the FERC, the Utility entered into settlement agreements with several ETCs under which the settling ETCs paid the Utility compromised amounts in full satisfaction of past due SC costs. Most of the settlement agreements provided that if the Utility's pending appeal to the D.C. Circuit was successful, the Utility would refund the settlement amounts paid by the ETCs.

In July 2005, the D.C. Circuit issued an order finding that the Utility was not barred from recovering the SC costs through the TRBA and remanded the matter to the FERC for further action. In December 2005, the FERC issued an order concluding that the Utility should recover the SC costs through the TRBA mechanism or through bilateral agreements with the ETCs but could not recover the costs through the SCS Tariff, and the FERC terminated the SCS Tariff proceeding. On May 22, 2006, the FERC issued an order further clarifying that the Utility could recover through the TRBA all of the costs that it had incurred as an SC and ordered the Utility to refund to the ETCs all amounts paid by the ETCs to the Utility pursuant to the SCS Tariff. As of July 31, 2006, the Utility had made refunds to the ETCs pursuant to the FERC's May 2006 order and the settlement agreements that required refunds to be made if the Utility's appeal was successful.

On April 4, 2006, the Utility filed an application with the FERC seeking approval of the \$109 million that the Utility recorded as SC costs from April 1998 through July 2005, together with interest of \$47 million accrued over that time period. The Utility requested that the FERC permit the Utility to recover these costs from TO Tariff customers over three and one-half years. On June 22, 2006, the Utility filed additional information to supplement the application as directed by the FERC. The Utility also filed an advice letter with the CPUC notifying the CPUC that the Utility will seek to pass through the portion of any FERC-approved SC costs that is allocable to the Utility's retail electric customers. In light of these events, in the quarter ended June 30, 2006, the Utility's net income increased by approximately \$22 million, or \$37 million pre-tax, reflecting the portion of SC costs determined to be probable of recovery through the TRBA and the reversal of a reserve for SC costs under the SCS Tariff which was terminated by the FERC, offset by SCS refunds to the ETCs.

On August 31, 2006, the Utility received an order from the FERC approving the Utility's April 4, 2006 application. On September 30, 2006, the order was no longer subject to rehearing or appeal. In light of this FERC order, the Utility determined that all SC costs are probable of recovery from TO Tariff customers through the TRBA, resulting in an overall increase to the Utility's pre-tax income of \$92 million and \$129 million, respectively, for the three and nine months ended September 30, 2006, reflecting SC costs incurred from April 1998 through September 2006. SC costs incurred after

September 30, 2006 and in the future are considered probable of recovery through the TRBA.

Spent Nuclear Fuel Storage Proceedings

Under the Nuclear Waste Policy Act of 1982, the U.S. Department of Energy, or DOE, is responsible for the transportation, permanent storage and disposal of spent nuclear fuel and high-level radioactive waste. The DOE has been unable to meet its contractual commitments to utilities with nuclear facilities to begin accepting spent fuel at one or more permanent disposal sites by 1998 as required by the Nuclear Waste Policy Act of 1982. Under the Utility's contract with the DOE to provide for the disposal of spent nuclear fuel and high-level radioactive waste from the Utility's two nuclear power facilities at Diablo Canyon, if the DOE completes a storage facility by 2010, the earliest that Diablo Canyon's spent fuel would be accepted for storage or disposal is expected to be 2018. At the projected level of operation for Diablo Canyon, the Utility's current facilities are able to store on site all spent fuel produced through approximately 2010 for Unit 1 and 2011 for Unit 2. As a result of the DOE's failure to develop a permanent storage facility, the Utility has been required to incur substantial costs for planning and developing on-site storage options for spent nuclear fuel at Diablo Canyon and the retired nuclear facility at Humboldt Bay, or Humboldt Bay Unit 3. As further described in the 2005 Annual Report, the Utility is seeking to recover these costs from the DOE on the basis that DOE has breached its contractual obligation to move used nuclear fuel from Diablo Canyon and Humboldt Bay Unit 3 to a national repository beginning in 1998. On October 13, 2006, the U.S. Court of Federal Claims issued a decision awarding approximately \$42.8 million in damages to the Utility. This amount will be credited to customers pending any appeals.

In March 2004, the Nuclear Regulatory Commission, or NRC, authorized the Utility to build an on-site dry cask storage facility to store spent fuel. The license is effective for 20 years, with an option to renew for another 20 years under the applicable regulations. Several interveners in that proceeding filed an appeal of the NRC's decision with the U.S. Court of Appeals for the Ninth Circuit, or the Ninth Circuit, on the grounds that the NRC should have considered the terrorist threat against the dry cask storage facility as part of the environmental review under the National Environmental Policy Act, or NEPA. On June 2, 2006, the Ninth Circuit granted the appeal in part and ordered that the case be remanded to the NRC for further consideration of the terrorist threat issue as part of a supplemental NEPA assessment. Before issuing the license in March 2004, the NRC reviewed the terrorist threat issue as part of its safety and design assessment under the Atomic Energy Act. On September 29, 2006, the Utility requested that the U.S. Supreme Court review the Ninth Circuit's decision.

In addition, some of the interveners in the case filed a request with the NRC seeking an injunction to prevent the Utility from loading used fuel in its on-site storage facility until the NRC has completed its additional environmental review. The interveners also sought a declaratory order from the NRC that if the Utility proceeds with construction of the on-site storage facility prior to completion of the NRC's additional environmental review, it does so at the risk that a new permit may be denied or that it may have to change the design and construction of the facility in response to the environmental review. The Utility believes that prior legal precedent allows it to continue construction of the on-site storage facility and to load fuel and commence operations of the facility while the appellate process is pending. On July 17, 2006, the Utility filed a response at the NRC objecting to the interveners' request for injunctive and declaratory relief. On September 6, 2006, the NRC denied the request for injunctive and declaratory relief. The NRC has not yet ruled on the interveners' request that the NRC reconsider its decision to deny injunctive and declaratory relief.

Construction of the on-site dry cask storage facility began in the third quarter of 2005 and is expected to be completed by 2008. In November 2005, the NRC authorized the Utility to install a temporary storage rack in each unit's existing spent fuel storage pool that would permit the Utility to operate Unit 1 until 2010 and Unit 2 until 2011. The Utility expects to complete the installation of the temporary storage racks by December 2006. If the Utility is unable to complete the dry cask storage facility, or if construction is delayed beyond 2010, and if the Utility is otherwise unable to increase its on-site storage capacity, it is possible that the operation of Diablo Canyon may have to be curtailed or halted as early as 2010 with respect to Unit 1 and 2011 with respect to Unit 2 and until such time as additional spent fuel can be safely stored. If electricity from Diablo Canyon were unavailable, the Utility would be required to purchase electricity from other more expensive sources to meet its customers' demand.

Defined Benefit Pension Plan Contribution

On June 16, 2006, the CPUC issued a decision adopting a pension settlement among the Utility, the DRA, and the Coalition of California Utility Employees that will allow the Utility to recover revenue requirements associated with annual contributions to fund the Utility's pension plan from 2006 to 2009. On a projected basis, these contributions will bring the pension trust plan to fully funded status as of January 1, 2010.

On July 20, 2006, the Utility made the 2006 authorized net pension contribution of \$250 million funded by the authorized \$155 million revenue requirement attributable to the Utility's distribution and generation operations, or GRC lines of business. Approximately \$20 million of the \$250 million contribution relates to revenue requirements for gas transmission and storage, electric transmission, and nuclear decommissioning, which have been or will be addressed in other CPUC or FERC proceedings. The remaining 2006 contribution amount will be capitalized. Additional pension contributions of \$40 million associated with the 1994 voluntary retirement incentive, \$3 million for PG&E Corporation participants, and \$1 million for interest on the net pension contributions were also made during the quarter.

For 2007, 2008, and 2009, the annual pension-related revenue requirement attributable to the GRC lines of business will decrease to approximately \$98 million. If the proposed settlement agreement in the Utility's 2007 GRC is approved, the Utility would be authorized to fund a net pension contribution of \$153 million in 2010, with an associated revenue requirement attributable to the GRC lines of business of approximately \$98 million.

CPUC Proceeding Regarding Holding Companies and their Affiliates

On June 29, 2006, the CPUC issued an amendment to an October 2005 Order Instituting Rulemaking, or OIR, to allow the CPUC to re-examine the relationship between California energy utilities and their parent holding companies and affiliates in furtherance of the CPUC's goals to ensure that California's regulated utilities meet their public service obligations and that the utilities do not favor or otherwise engage in preferential treatment of their affiliates. In the amended OIR, the CPUC noted that the original intent of its affiliate transaction rules had not been fulfilled largely due to the numerous exceptions to the rules and to what the CPUC considered to be the utilities' overly narrow interpretations of the rules. On October 10, 2006, the CPUC administrative law judge overseeing the proceeding issued a draft decision containing proposed revisions to the current rules. The proposals include additional reporting requirements regarding communications of a utility's confidential information about certain subjects to the holding company or non-utility affiliates, a new requirement that the utilities be "ring fenced" to protect them from being consolidated into a bankruptcy proceeding of their holding companies or their non-utility affiliates, extending the prohibition on certain shared services to other areas, and a new requirement that the CPUC pre-approve contracts between a utility and an affiliate for resource procurement (except in transactions where the identity of the counterparty is not known until the transaction is consummated). On October 30, 2006, the Utility and PG&E Corporation filed comments on the draft decision noting that while some of the proposed changes were not objectionable, other proposed changes would unduly restrict the functioning of the holding company structure and impede the Utility's ability to function. These include proposed rules to 1) require detailed reporting of certain communications between a utility and its holding company personnel, 2) prohibit the sharing of certain important functions among a utility, its holding company and affiliates, and 3) prohibit a utility and its affiliates from jointly employing contractors and consultants. The CPUC is expected to issue a final decision before the end of the year.

PG&E Corporation and the Utility cannot predict whether any rules that the CPUC may adopt will have a material impact on their results of operations or financial condition.

Pending CPUC Investigation

In February 2005, the CPUC issued a ruling opening an investigation into the Utility's billing and collection practices and credit policies. The investigation was initiated at the request of TURN, after the CPUC's January 13, 2005 decision that characterized the definition of "billing error" in a revised Utility tariff to include delayed bills and Utility-caused estimated bills as being consistent with "existing CPUC policy, tariffs, and requirements." The Utility contends that prior to the CPUC's January 13, 2005 decision, "billing error" under the Utility's former tariffs did not encompass delayed bills or Utility-caused estimated bills. The Utility's petition asking the appellate court to review the CPUC's decision denying rehearing of its January 13, 2005 decision is still pending.

On February 3, 2006, the CPUC's Consumer Protection and Safety Division, or CPSD, and TURN submitted their reports to the CPUC concluding that the Utility violated applicable tariffs related to delayed and estimated bills. The CPSD recommended that the Utility refund to customers \$117 million, plus interest at the three-month commercial paper interest rate, that allegedly was collected in violation of the tariffs. TURN recommended that the Utility refund to customers \$53 million, plus interest at the three-month commercial paper interest rate, that allegedly was collected in violation of the tariffs. The two refunds are not additive. The CPSD also recommended that the Utility pay fines of \$6.75 million, while TURN recommends fines in the form of a \$1 million contribution to Relief for Energy Assistance through Community Help. Both the CPSD and TURN recommend that refunds and fines be funded by shareholders. In May and July 2006, the CPSD and TURN indicated they had reduced their recommended refund amounts to approximately \$54 million and \$36 million, respectively, plus interest at the three-month commercial paper interest rate. It is uncertain when the CPUC will issue a final decision.

If the CPUC finds that the Utility violated applicable tariffs or the CPUC's orders or rules, the CPUC may seek to order the Utility to refund any amounts collected in violation of tariffs, plus interest, to customers who paid such amounts. In addition, if the CPUC finds that the Utility violated applicable tariffs or the CPUC's orders or rules, the CPUC may seek to impose penalties on the Utility.

PG&E Corporation and the Utility do not expect the outcome of this matter will have a material adverse effect on PG&E Corporation's or the Utility's financial condition or results of operations .

Energy Efficiency Rulemaking

On April 13, 2006, the CPUC issued an OIR to consider establishing new energy efficiency policies and programs, including mechanisms that would provide incentives or impose penalties on the investor-owned utilities depending on the extent to which the utilities successfully implement their 2006-2008 energy efficiency programs and meet the CPUC's targets for reducing customers' demand for electricity and natural gas. Under the Utility's current proposed incentive mechanism, if the Utility achieved 80% to 100% of the CPUC's demand reduction targets, 80% of the net present value of energy efficiency programs (i.e., the net benefits) would accrue to customers and 20% of the net benefits would accrue to shareholders. If the Utility exceeds 100% of the CPUC's targets, the Utility's shareholders would receive 30% of the additional net benefits attributable to the portion of demand reduction that exceeds 100% of the CPUC's targets and the Utility's customers would receive the remaining 70%. Other parties have proposed that the Utility begin earning incentives only when the Utility reached 85% of the CPUC's targets and obtain earnings ranging from only 1% to 3% of the net benefits. All parties have proposed penalties for poor performance in achieving the CPUC's targets. The Utility has proposed that if it achieves less than 40% of the CPUC's targets, the Utility would provide customers any shortfall between the revenues received in rates for energy efficiency and benefits obtained through the energy efficiency programs. Other parties have proposed that penalties be imposed if the Utility achieves less than 50% to 85% of the CPUC's targets. It is anticipated that the CPUC will issue a final decision on the adoption of a shareholder incentive/penalty mechanism in late 2006 or in early 2007. Actual shareholder incentives or penalties may not be realized for several years, depending upon the ratemaking method adopted by the CPUC. In addition to proposed mechanisms for shareholder incentives or penalties, other issues to be considered in the OIR include evaluation, measurement and verification of the Utility's energy efficiency implementation results; energy and water savings; and planning for energy efficiency programs to be implemented in 2009-2011. PG&E Corporation and the Utility are unable to predict what rules and policies the CPUC may ultimately adopt and what impact the adopted shareholder incentive/penalty mechanism may have on their financial condition and results of operations.

Cost of Capital

On August 24, 2006, the CPUC granted the Utility's request to waive the requirement for the Utility to file a 2007 cost of capital application and to maintain the Utility's currently authorized cost of capital and capital structure for 2007. For 2006 and 2007, the Utility's authorized capital structure consists of 46% long-term debt, 2% preferred stock and 52% equity. The authorized rates of return that the Utility may earn on its electricity and natural gas distribution and electricity generation rate base for 2006 and 2007 is 6.02% for long-term debt, 5.87% for preferred stock, and 11.35% for equity, resulting in an overall rate of return on rate base of 8.79%. The Chapter 11 Settlement Agreement requires the CPUC to authorize a minimum ROE for the Utility of 11.22% until the Utility receives a credit rating of "A3" from Moody's Investor Services or "A-" from Standard & Poor's Rating Services. The CPUC will next re-evaluate the level of the Utility's authorized ROE and capital structure for the calendar year 2008. The Utility's rate of return for its electric transmission operations is set by the FERC and the Utility's rate of return for its gas transmission and storage operations through 2007 has been previously set in the Gas Accord settlement agreement approved by the CPUC.

Catastrophic Event Memorandum Account Application

From late December 2005 to early January 2006, winter storms disrupted service to approximately 1.5 million electric customers and damaged electric distribution facilities and generation facilities, causing the Utility to incur approximately \$27 million in additional costs to restore service and repair facilities. In addition, from mid to late July 2006, all parts of the Utility's service territory experienced unusually high temperatures, contributing to a "heat storm" that disrupted service to approximately 1.2 million electric customers and damaged electric distribution facilities, causing the Utility to incur approximately \$41 million in additional costs to restore service and repair facilities.

The CPUC allows utilities to recover the reasonable costs of responding to catastrophic events through a CEMA. The CEMA tariff authorizes recovery of costs when a formal disaster has been declared by the Governor or a competent federal authority. By proclamations dated January 2, January 3, and January 12, 2006, the California Governor proclaimed a

state of emergency to exist due to the damage caused by the winter storms. On September 7, 2006, the United States Department of Agriculture declared 16 of California's counties to be natural disaster areas, as a result of the July "heat storm" and 31 additional counties as "contiguous" counties also eligible for federal relief. Among other issues to be decided in a CEMA proceeding, the CPUC conducts a review to determine whether the costs were prudently incurred.

The Utility plans to file its 2006 CEMA application for the winter storms and July 2006 "heat storm" on or about November 13, 2006, requesting rate recovery of approximately \$52 million in 2008 rates for recovery of the CEMA costs. PG&E Corporation and the Utility are unable to predict whether the CPUC will approve the CEMA application or the amount of any potential recovery.

Energy Recovery Bond Balancing Account

In connection with the issuance of the ERBs, the Utility established a balancing account, the ERBBA, as authorized by the CPUC, to track various costs and benefits associated with the ERBs. Among other ERB-related costs and benefits, the Utility is required to use the ERBBA to return to customers the benefits of energy supplier refunds received after the issuance of the second series of ERBs. The energy supplier refunds that the Utility received between the issuance of the first and second series of ERBs were used to reduce the size of the second series of ERBs. The ERBBA tariff also provides that reasonable net interest costs on energy supplier claims and refunds incurred subsequent to the issuance of the first series of ERBs shall be deducted in order to calculate the net amount of energy supplier refunds.

As of December 31, 2005, the Utility had accrued approximately \$1.2 billion of net disputed claims filed by various energy suppliers in its Chapter 11 proceeding. The ERBBA liability balance was approximately \$222 million as of December 31, 2005, which included approximately \$170 million credited to the ERBBA as a result of energy supplier settlements and a reserve of approximately \$65 million of net interest costs charged to ERBBA related to the net disputed claims for the period between April 12, 2004, the effective date of the Utility's plan of reorganization, and February 10, 2005, when the first series of ERBs was issued, and certain energy supplier refund litigation costs, pending recovery. Following the completion of the CPUC's verification audit in the 2005 AET, the Utility concluded that the previously reserved \$65 million is probable of recovery. The reversal of this reserve resulted in an increase in electric operating revenues of approximately \$65 million in the three and nine months ended September 30, 2006.

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 transmission and storage, other goods and services, and other aspects of their business. 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 risks, see "Risk Management Activities" in the MD&A section of the 2005 Annual Report. The following disclosures omit certain information that has not changed since the 2005 Annual Report was filed with the SEC.

Price Risk

Natural Gas Transmission and Storage

The Utility uses value-at-risk to measure the Utility's exposure to price and volumetric risks that could impact revenues due to changes in market prices, customer demand, and weather. 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 99% confidence level, which means that there is a 1% 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 may not adequately capture portfolio risk.

The Utility's value-at-risk calculated under the methodology described above was approximately \$36 million and \$31 million at September 30, 2006 and December 31, 2005, respectively. The Utility's high, low, and average value-at-risk during the nine months ended September 30, 2006 was approximately \$41 million, \$22 million, and \$33 million, respectively. The Utility's high, low, and average value-at-risk during the year ended December 31, 2005 was approximately

\$43 million, \$31 million, and \$36 million, respectively.

Convertible Subordinated Notes

As of September 30, 2006, PG&E Corporation had outstanding \$280 million of 9.50% Convertible Subordinated Notes, or Convertible Subordinated Notes, that are scheduled to mature on June 30, 2010. Holders of the Convertible Subordinated Notes are entitled to receive “pass-through dividends” at the same payout ratio as common shareholders, with the number of shares determined by dividing the principal amount of the Convertible Subordinated Notes by the conversion price.

In accordance with SFAS No. 133, “ Accounting for Derivative Instruments and Hedging Activities, ” the dividend participation rights component is considered to be an embedded derivative instrument and, therefore, must be bifurcated from the Convertible Subordinated Notes and recorded at fair value in PG&E Corporation's Condensed Consolidated Financial Statements. Changes in the fair value are recognized in PG&E Corporation's Condensed Consolidated Statements of Income as a non-operating expense or income (included in Other income (expense), net). At September 30, 2006 and December 31, 2005, the total estimated fair value of the dividend participation rights component, on a pre-tax basis, was approximately \$82 million and \$92 million, respectively, of which \$23 million and \$22 million, respectively, is classified as a current liability (in Current Liabilities - Other) and \$59 million and \$70 million, respectively, is classified as a noncurrent liability (in Noncurrent Liabilities - Other).

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, 2006, 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 by an immaterial amount, 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 to their complexity, because their application is 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 2005 Annual Report. They include:

- Regulatory Assets and Liabilities;
- Unbilled Revenues;
- Environmental Remediation Liabilities;
- Asset Retirement Obligations;
- Income Taxes; and
- Pension and Other Postretirement Benefits.

For the period ended September 30, 2006, 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

Share-Based Payment

In December 2004, the Financial Accounting Standards Board, or FASB, issued SFAS No. 123 (revised December 2004), "Share-Based Payment," or SFAS No. 123R. SFAS No. 123R requires that the cost of all share-based payment transactions be recognized in the financial statements and establishes a fair-value measurement objective in determining the value of such costs.

Effective January 1, 2006, PG&E Corporation and the Utility adopted the fair value recognition provisions of SFAS No. 123R. The impact of adopting SFAS No. 123R is disclosed in Note 2 and Note 8 of the Notes to the Condensed Consolidated Financial Statements. See Note 2 for additional new accounting policies.

Variable Interest Entities

In April 2006, the FASB issued Staff Position No. FIN 46R-6, "Determining the Variability to Be Considered in Applying FASB Interpretation No. 46R," or FSP FIN 46R-6. FSP FIN 46R-6 specifies how a company should determine variability in applying the accounting standard for consolidation of variable interest entities.

PG&E Corporation and the Utility adopted FSP FIN 46R-6 on July 1, 2006. The impact of adopting FSP FIN 46R-6 is disclosed in Note 2 of the Notes to the Condensed Consolidated Financial Statements. See Note 2 for additional new accounting policies.

ACCOUNTING PRONOUNCEMENTS ISSUED BUT NOT YET ADOPTED

Refer to Note 2 of the Notes to the Condensed Consolidated Financial Statements for further discussion.

ADDITIONAL SECURITY MEASURES

Various federal regulatory agencies have issued guidance and the NRC has issued orders regarding additional security measures to be taken at various facilities, including generation facilities, transmission substations and natural gas transportation facilities. The guidance and the orders require additional capital investment and increased operating costs. However, neither PG&E Corporation nor the Utility believes that these costs will have a material impact on their financial condition or results of operations.

ENVIRONMENTAL AND LEGAL MATTERS

PG&E Corporation and the Utility are subject to laws and regulations established both to maintain and improve the quality of the environment. Where PG&E Corporation's and the Utility's properties contain hazardous substances, these laws and regulations may require PG&E Corporation and the Utility to remove those substances or to remedy the effects of those hazardous substances on the environment. As described in Note 11 of the Notes to the Condensed Consolidated Financial Statements, the Utility had an undiscounted environmental remediation liability of approximately \$513 million at September 30, 2006, and approximately \$469 million at December 31, 2005. The increase in the undiscounted environmental remediation liability is partly due to an increase in estimated costs as a result of changes in the California Regional Water Quality Control Board's imposed remediation levels associated with the Utility's gas compressor station located near Hinkley, California. Costs incurred at this facility are not recoverable from customers and, as a result, net income was reduced by \$19 million for the nine months ended September 30, 2006. In addition, the Utility increased its estimated remediation costs associated with its gas compressor station located near Topock, Arizona. Ninety percent of this additional cost is allowable for inclusion in future rates in accordance with the hazardous waste ratemaking mechanism which permits the Utility to recover 90% of hazardous waste remediation costs from customers without a reasonableness review. For the nine months ended September 30, 2006, the increase in the undiscounted environmental remediation liability due to the Hinkley and Topock facilities was \$63 million, of which \$54 million was accrued during the second quarter 2006.

In the normal course of business, PG&E Corporation and the Utility are named as parties in a number of claims and lawsuits. As described in Note 11 of the Notes to the Condensed Consolidated Financial Statements, the accrued liability for legal matters is included in PG&E Corporation's and the Utility's other current liabilities in the Condensed Consolidated Balance Sheets, and totaled approximately \$71 million at September 30, 2006 and \$388 million at December 31, 2005. The Utility has accrued approximately \$19 million with respect to the Chromium Litigation, as described in Note 11 of the Notes to the Condensed Consolidated Financial Statements. PG&E Corporation and the Utility do not believe that the ultimate outcome of the Chromium Litigation will have an additional material adverse impact on their financial condition or results of operations.

As disclosed in PG&E Corporation's and the Utility's 2005 Annual Report, the U.S. Environmental Protection

Agency, or EPA, published regulations under Section 316(b) of the Clean Water Act for cooling water intake structures. The regulations affect existing electricity generation facilities using over 50 million gallons per day, typically including some form of "once-through" cooling such as that used at Diablo Canyon. These regulations establish a set of performance standards that vary with the type of water body and that are intended to reduce impacts to aquatic organisms. In June 2006, the California State Water Resources Control Board issued a proposed policy to implement these new EPA regulations in California. Unlike the EPA regulations which allow site-specific compliance determinations if a facility's cost of compliance is significantly greater than either the benefits achieved or the compliance costs considered by the EPA, the proposed California policy would not permit site-specific cost/benefit determinations. If adopted, the Utility may be required to incur material capital expenditures to achieve compliance with these regulations or cease operations temporarily or permanently. If the Utility is unable to recover the costs of compliance with these regulations, or if the Utility ceased to operate Diablo Canyon, PG&E Corporation's and the Utility's future financial results and condition would be materially and adversely affected.

ITEM 3: QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

ITEM 4: CONTROLS AND PROCEDURES

Based on an evaluation of PG&E Corporation's and the Utility's disclosure controls and procedures as of September 30, 2006, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures are effective to ensure that information required to be disclosed by PG&E Corporation and the Utility in reports the companies file or submit under the Securities and Exchange Act of 1934, or the Act, is recorded, processed, summarized, and reported within the time periods specified in the SEC rules and forms. In addition, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures were effective in ensuring that information required to be disclosed by PG&E Corporation and the Utility in the reports that PG&E Corporation and the Utility file or submit under the Act is accumulated and communicated to PG&E Corporation's and the Utility's management, including PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

As of January 1, 2004, PG&E Corporation and the Utility adopted the Financial Accounting Standards Board, or FASB, revision to FASB Interpretation No. 46, "Consolidation of Variable Interest Entities," or FIN 46R. In accordance with FIN 46R, the Utility consolidated the assets, liabilities and non-controlling interests of a low-income housing partnership that was determined to be a variable interest entity, or VIE, under FIN 46R. PG&E Corporation and the Utility do not have the legal right or authority to assess the internal controls of the VIE. Therefore, PG&E Corporation's and the Utility's evaluation of disclosure controls and procedures performed as of September 30, 2006, did not include this entity in that evaluation. PG&E Corporation and the Utility have not designed, established, or maintained disclosure controls and procedures for the consolidated VIE.

There were no changes in internal controls over financial reporting that occurred during the quarter ended September 30, 2006, that have materially affected, or are reasonably likely to materially affect, PG&E Corporation's or the Utility's internal controls over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Pacific Gas and Electric Company Chapter 11 Filing

For information regarding the Utility's Chapter 11 proceeding, see "Part I, Item 3: Legal Proceedings" of the 2005 Annual Report and Note 10 of the Notes to the Condensed Consolidated Financial Statements included in this report and PG&E Corporation's and the Utility's Quarterly Report on Form 10-Q for the quarter ended June 30, 2006.

Pacific Gas and Electric Company v. Michael Peevey, et al.

For information regarding this matter, see "Part I, Item 3: Legal Proceedings" in the 2005 Annual Report.

Diablo Canyon Power Plant

For information regarding matters relating to the Diablo Canyon Power Plant, see "Part I, Item 3: Legal Proceedings" in the 2005 Annual Report.

Compressor Station Chromium Litigation

For more information regarding the Chromium Litigation, see "Part I, Item 3: Legal Proceedings" in the 2005 Annual Report and Note 11 to the Notes to the Condensed Consolidated Financial Statements included in this report and PG&E Corporation's and the Utility's Quarterly Reports on Form 10-Q for the quarters ended March 31, 2006 and June 30, 2006.

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

On October 2, 2006, the U.S. Supreme Court declined to grant PG&E Corporation's request to review a January 10, 2006 ruling by the Ninth Circuit that found that certain claims brought against PG&E Corporation and certain directors by the California Attorney General and the City and County of San Francisco had been improperly removed from the California Superior Court where they were originally brought to the Bankruptcy Court where the Utility's Chapter 11 case was pending. In light of the U.S. Supreme Court's action, the plaintiffs have resumed pursuing these claims in Superior Court.

PG&E Corporation believes that the California Attorney General's and City and County of San Francisco's allegations have no merit and will continue to vigorously respond to and defend against the litigation. PG&E Corporation believes that the ultimate outcome of this matter would not result in a material adverse effect on PG&E Corporation's financial condition or results of operations.

For more information regarding these cases, see "Part I, Item 3: Legal Proceedings" of the 2005 Annual Report and PG&E Corporation's and the Utility's Quarterly Reports on Form 10-Q for the quarters ended March 31, 2006 and June 30, 2006.

ITEM 1A. RISK FACTORS

A discussion of the significant risks associated with investments in the securities of PG&E Corporation and the Utility is set forth under the heading "Management's Discussion and Analysis of Financial Condition and Results of Operations - Risk Factors" in the 2005 Annual Report. The last risk factor appearing in the 2005 Annual Report discussed the possibility that the Bankruptcy Court's order confirming the Utility's Chapter 11 plan of reorganization could be overturned or modified on appeal. As disclosed above, under "Item 1. Legal Proceedings - Pacific Gas and Electric Company Chapter 11 Filing," the time period during which the appellants could have filed a petition for rehearing with the U.S. Supreme Court has expired, rendering the confirmation order final and no longer subject to appeal. There have been no other material changes in the risks related to an investment in PG&E Corporation's or the Utility's securities that have been disclosed in the 2005 Annual Report. In addition, the section of this report entitled "Forward Looking Statements" appearing in Part I, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations, lists some of the factors that could affect PG&E Corporation's and the Utility's future results of operations and financial condition. Although PG&E Corporation and the Utility are not able to predict all the factors that may affect future results, the listed factors and the risks discussed in the Annual Report could cause actual results to differ materially from the results expected or

anticipated by management as expressed or implied by the forward-looking statements made in the 2005 Annual Report and in this report.

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

As previously disclosed, in connection with its entry into certain credit agreements, in June 2002 and October 2002, PG&E Corporation issued warrants to purchase 5,066,931 shares of common stock of PG&E Corporation at an exercise price of \$0.01 per share. During the quarter ended September 30, 2006, warrant holders exercised, on a net exercise basis, warrants to purchase 51,904 shares, and received 51,890 shares of PG&E Corporation common stock. As of September 30, 2006, warrant holders had exercised, on a net exercise basis, warrants to purchase 5,066,931 shares, and had received 5,065,099 shares of PG&E Corporation common stock since the warrants were issued. There are no more warrants outstanding.

The Utility did not make any sales of unregistered equity securities during the quarter ended September 30, 2006, the period covered by this report.

Issuer Purchases of Equity Securities

PG&E Corporation common stock:

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs ⁽¹⁾	Approximate Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs
July 1 through July 31, 2006	-	\$ -	-	\$ 500,000,000
August 1 through August 31, 2006	-	\$ -	-	\$ 500,000,000
September 1 through September 30, 2006	-	\$ -	-	\$ 500,000,000
Total	-	\$ -	-	\$ 500,000,000

⁽¹⁾ On October 19, 2005, the PG&E Corporation Board of Directors authorized the repurchase of up to \$1.6 billion in shares of PG&E Corporation's common stock from time to time, but no later than December 31, 2006. The program was publicly announced in a Current Report on Form 8-K filed by PG&E Corporation on October 21, 2005. As described in a Current Report on Form 8-K filed by PG&E Corporation on November 18, 2005, PG&E Corporation entered into an accelerated share repurchase arrangement with Goldman Sachs & Co., or GS&Co., on November 16, 2005, or the November 16 ASR, under which PG&E Corporation repurchased 31,650,300 shares of its outstanding common stock at an initial price of \$34.75 per share and an aggregate price of approximately \$1.1 billion. The share forward component of the November 16 ASR was terminated in accordance with its terms on March 28, 2006. In connection with the termination, PG&E Corporation paid GS&Co. approximately \$58 million (net of amounts payable by GS&Co. to PG&E Corporation), including a price adjustment based on the difference between \$34.75 per share, and the volume weighted average price, or VWAP, of PG&E Corporation common stock from November 17, 2005 through March 28, 2006. On March 28, 2006, PG&E Corporation entered into a new share forward agreement with GS&Co. to complete the share forward component of the November 16 ASR. The new forward share agreement was terminated in accordance with its terms on June 8, 2006. In connection with the termination, on June 13, 2006, PG&E Corporation paid GS&Co. approximately \$56 million (net of amounts payable by GS&Co. to PG&E Corporation), including a price adjustment based on the difference between \$34.75 per share, and the VWAP of PG&E Corporation common stock from March 29, 2006 through June 8, 2006.

During the third quarter of 2006, Pacific Gas and Electric Company did not redeem or repurchase any shares of its various series of preferred stock outstanding.

ITEM 5. OTHER INFORMATION

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

The Utility's earnings to fixed charges ratio for the three and nine months ended September 30, 2006 was 4.63 and 3.63, respectively. The Utility's earnings to combined fixed charges and preferred stock dividends ratio for the three and nine months ended September 30, 2006, was 4.55 and 3.56, 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 333-109994 relating to various series of the Utility's first preferred stock and its senior notes,

respectively.

ITEM 6. EXHIBITS

- 10.1* Offer of Employment between Pacific Gas and Electric Company and William T. Morrow dated June 20, 2006
- 10.2* Retention Agreement Between PG&E Corporation and Thomas B. King dated August 31, 2006
- 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

G. Robert Powell

G. Robert Powell
Vice President and Controller
(duly authorized officer and principal accounting officer)

PACIFIC GAS AND ELECTRIC COMPANY

G. Robert Powell

G. Robert Powell
Vice President and Controller
(duly authorized officer and principal accounting officer)

Dated: November 8, 2006

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.

June 20, 2006

Mr. William Morrow
Homat Viscount #2801
1-11-40 Akasaka, Minato-ku
Tokyo 107-0052 Japan

Dear Bill:

On behalf of Pacific Gas and Electric Company, I am pleased to extend an offer to you to join our organization as President and Chief Operating Officer, reporting to me.

Your initial total compensation package will consist of the following:

1. An annual base salary of \$575,000 (\$47,916.67/month) subject to possible increases through our annual salary review plan.
2. A one-time bonus of \$100,000 payable within 60 days of your date of hire, subject to normal tax withholdings. Should you leave the company or should your employment be terminated for cause within three years of your date of hire, a prorated amount of this bonus must be refunded to the company.
3. A target incentive of \$373,750 (65% of your base salary) in an annual short-term incentive plan under which your actual incentive dollars may range from zero to \$747,500 based on performance relative to established goals. This incentive will be prorated for the number of months worked from your date of hire and will be payable in 2007.
4. Participation in the PG&E Corporation Long-Term Incentive Plan (LTIP) as a band 2 officer. Grants under the LTIP are split equally between restricted stock and performance shares, and are generally made annually on the first business day of the year. Your initial grant will be made on your date of hire and will have an estimated current value of \$1,000,000. This estimated value is used only for the purpose of determining the number of shares for your grant. The ultimate value that you realize from this grant will depend upon your employment status and the performance of PG&E Corporation common stock.
5. A one-time supplement LTIP grant with an estimated current value of \$500,000. This grant will be apportioned and made in the same manner as the grant described in item 4.

Mr. Morrow
June 20, 2006
Page 2

6. Participation in the PG&E Corporation Supplemental Executive Retirement Plan (SERP). The basic benefit payable from the SERP at retirement is a monthly annuity equal to the product of 1.7% x [average of the three highest years' combination of salary and annual incentive for the last ten years of service] x years of credited service x 1/12 less any amounts paid or payable from the Pacific Gas and Electric Company Retirement Plan (RP).
7. Conditioned upon meeting plan requirements, you will also be eligible for post-retirement life insurance and post-retirement medical benefits upon retirement under the RP.
8. Participation in the PG&E Corporation Retirement Savings Plan (RSP), a 401(k) savings plan. You will be eligible to contribute as much as 20% of your salary on either a pre-tax or after-tax basis. After your first year of service, we will match contributions you make up to 3% of your salary at 75 cents on each dollar contributed. After three years of service, we will match contributions up to 6% of your salary at 75 cents on each dollar contributed. All of the above contributions are subject to the applicable legal limits.

9. Participation in the PG&E Corporation Supplemental Retirement Savings Plan (SRSP), a non-qualified, deferred compensation plan. You may elect to defer payment of some of your compensation on a pre-tax basis. We will provide you with the full matching contributions that cannot be provided through the RSP, due to legal limitations imposed on highly compensated employees.
 10. As a result of your officer level (officer band 2), you will become an eligible participant under the Executive Stock Ownership Program effective January 1, 2007. As an ancillary benefit to that program, you will also be eligible to receive financial counseling from The AYCO Company at a subsidized rate to assist you in your understanding of our compensation and benefits programs and how those programs can help you to achieve financial security. For this feature of the program, you will be eligible as of your date of hire.
 11. Participation in a cafeteria-style benefits program that permits you to select coverage tailored to your personal needs and circumstances. The benefits you elect will be effective the first of the month following the date of your hire.
 12. An annual vacation allotment of four weeks, subject to future increases based on length of service. Your initial vacation allotment will be prorated based on your date of hire. In addition, Pacific Gas and Electric Company recognizes 10 paid company holidays annually and provides 3 floating holidays immediately upon hire and at the beginning of each year.
 13. An annual perquisite allowance of \$25,000 to be used in lieu of individual authorizations for cars and memberships in clubs and civic organizations. If your date of hire is after June 30, 2006, you will receive half of this amount (\$12,500) for 2006.
 14. Participation in the Employee Discount program after six months of continuous service following your date of hire. The program offers participants a 25% discount on electricity and gas rates for their primary residence. In order to receive this benefit, you must (a) live within Pacific Gas and Electric Company's service territory and (b) have the service in your name at your primary residence.
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Mr. Morrow
June 20, 2006
Page 3

As we have discussed, this offer is contingent upon your passing a comprehensive background verification including a credit check and security clearance assessment, and a standard drug analysis test. We will also need to verify your eligibility to work in the United States based on applicable immigration laws. In addition, your election as an officer of Pacific Gas and Electric Company is subject to approval by the Board of Directors of Pacific Gas and Electric Company and elements of your compensation are subject to approval by the Nominating, Compensation, and Governance Committee of the Board of Directors of PG&E Corporation.

Peter Darbee and I look forward to your joining our team and believe you will make a strong contribution to the achievement of the mission and goals of Pacific Gas and Electric Company and PG&E Corporation. I would appreciate receiving your written acceptance of this offer and to also confirm a start date and public announcement of August 1, 2006 as soon as possible. It is our understanding that by June 28, 2006, and after your election by the Board of Directors to the position of President and Chief Operating Officer of Pacific Gas and Electric Company, that you will formally submit a letter to your current employer informing them that there is no acceptable position within Votaphone and invoking the severance provisions of your current executive officer contract.

Please call me at any time if you have questions.

Sincerely,

/s/ Thomas B. King

THOMAS B. KING
President and Chief Executive Officer

Attachment

This is to confirm my acceptance of Pacific Gas and Electric Company's offer as the President and Chief Operating Officer as outlined above.

/s/ William Morrow

June 20, 2006

(Signature and Date)

August 31, 2006

Exhibit 10.2

Mr. Thomas B. King
President and CEO
Pacific Gas and Electric Company
77 Beale Street, 32nd Floor
San Francisco, CA 94105

Dear Tom,

To provide a long-term incentive to retain your services, I am pleased to offer you the following modifications to your current compensation package:

- Elimination of Early Retirement Reduction Factors : The Board of Directors of Pacific Gas and Electric Company (Company) has agreed to eliminate the reduction factors that otherwise would be used to calculate your pension benefit under the defined benefit pension plan, provided you remain employed by the Company, PG&E Corporation, or any of their affiliates until age 55. This enhanced pension benefit will be paid from the PG&E Corporation Supplemental Executive Retirement Plan.
- Grant of Restricted Phantom Stock Units : At its July 12, 2006, meeting, the Nominating, Compensation and Governance Committee of the PG&E Corporation Board of Directors awarded you 25,433.41 restricted phantom stock units with an aggregate value of \$1 million based on the closing stock price of PG&E Corporation common stock on that day of \$39.63, as reported on the New York Stock Exchange. These units will be credited to your account in the PG&E Corporation Phantom Stock Investment Fund under the PG&E Corporation Supplemental Retirement Savings Plan (SRSP).
 - o *Vesting* . The restricted phantom stock units, together with any dividend equivalent units, will vest five years after the date of grant, provided that you are still employed by the Company, PG&E Corporation, or any of their affiliates. You may not elect to transfer the value of the units to another investment option in accordance with the SRSP until the units have vested.
 - o *Payment* . The amount of your deferred compensation account balance that is attributable to units that have vested shall be paid to you following your Retirement (as defined in the SRSP) or following your termination of employment.

Under certain situations, application or vesting of these benefits and awards may be accelerated. Upon your death or disability:

- the early retirement reduction factors will cease to apply for purposes of calculating the value of your pension benefit, and

Mr. Thomas B. King
August 31, 2006
Page 2

- the restricted phantom stock units, together with any dividend equivalent units, will immediately vest and will be paid in a lump sum as soon as practicable following the triggering event, based on the average closing price of a share of PG&E Corporation common stock for the last 30 calendar days preceding the date of the triggering event, as reported on the New York Stock Exchange.

These awards and benefits also will vest or accelerate as described in the prior paragraph if there is a Change in Control of PG&E Corporation (as defined in the PG&E Corporation 2006 Long-Term Incentive Plan (LTIP)) and these modifications to your compensation arrangements are not assumed by the Acquiror (as defined in the LTIP) or your employment is subject to an Involuntary Termination within the Covered Period following the Change in Control (as those terms are defined in the PG&E Corporation Officer Severance Policy).

If you are terminated without cause, a prorated portion of any unvested restricted phantom stock units and any dividend equivalent units will vest immediately, in accordance with the percentage of time you were employed by the Company, PG&E Corporation, or their affiliates during the 60-month vesting period. Those units will be forfeited if you are terminated for cause before the units vest. If you are terminated before you reach age 55, you will not receive the enhanced pension benefit, and early retirement reduction factors will apply. This paragraph does not apply if you are subject to an Involuntary Termination within the Covered Period in connection with a Change in Control.

Tom, you are and continue to be a very valued member of my senior management team and pivotal to the effort underway for the Company to become the leading utility in the United States. I am confident in your abilities and see you as a key player in the future of the Company.

Sincerely,

/s/ Peter A. Darbee

Accepted: /s/ Thomas B. King
Thomas B. King

Date: 8/31/06

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

(in millions, except share amounts)	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2006	2005	2006	2005
Net income	\$ 393	\$ 252	\$ 839	\$ 737
Less: distributed earnings to common shareholders	115	111	344	334
Undistributed earnings	278	141	495	403
Less: undistributed earnings from discontinued operations	-	13	-	13
Undistributed earnings from continuing operations	<u>\$ 278</u>	<u>\$ 128</u>	<u>\$ 495</u>	<u>\$ 390</u>
Common shareholders earnings				
Basic				
Distributed earnings to common shareholders	\$ 115	\$ 111	\$ 344	\$ 334
Undistributed earnings allocated to common shareholders - continuing operations	264	122	469	371
Undistributed earnings allocated to common shareholders - discontinued operations	-	12	-	12
Total common shareholders earnings, basic	<u>\$ 379</u>	<u>\$ 245</u>	<u>\$ 813</u>	<u>\$ 717</u>
Diluted				
Distributed earnings to common shareholders	\$ 115	\$ 111	\$ 344	\$ 334
Undistributed earnings allocated to common shareholders - continuing operations	264	122	469	371
Undistributed earnings allocated to common shareholders - discontinued operations	-	12	-	12
Total common shareholders earnings, diluted	<u>\$ 379</u>	<u>\$ 245</u>	<u>\$ 813</u>	<u>\$ 717</u>
Weighted average common shares outstanding, basic	347	372	345	376
9.50% Convertible Subordinated Notes	19	19	19	19
Weighted average common shares outstanding and participating securities, basic	<u>366</u>	<u>391</u>	<u>364</u>	<u>395</u>
Weighted average common shares outstanding, basic	347	372	345	376
Employee share-based compensation and accelerated share repurchase program ⁽¹⁾	2	4	4	4
Weighted average common shares outstanding, diluted ⁽²⁾	349	376	349	380
9.50% Convertible Subordinated Notes	19	19	19	19
Weighted average common shares outstanding and participating securities, diluted	<u>368</u>	<u>395</u>	<u>368</u>	<u>399</u>
Net earnings per common share, basic				
Distributed earnings, basic	\$ 0.33	\$ 0.30	\$ 1.00	\$ 0.89
Undistributed earnings - continuing operations, basic	0.76	0.33	1.36	0.99
Undistributed earnings - discontinued operations, basic	-	0.03	-	0.03
Total	<u>\$ 1.09</u>	<u>\$ 0.66</u>	<u>\$ 2.36</u>	<u>\$ 1.91</u>
Net earnings per common share, diluted				
Distributed earnings, diluted	\$ 0.33	\$ 0.30	\$ 0.99	\$ 0.88
Undistributed earnings - continuing operations, basic	0.76	0.32	1.34	0.98
Undistributed earnings - discontinued operations, basic	-	0.03	-	0.03

Total	<u>\$</u>	<u>1.09</u>	<u>\$</u>	<u>0.65</u>	<u>\$</u>	<u>2.33</u>	<u>\$</u>	<u>1.89</u>
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⁽¹⁾ Includes approximately one million shares treated as outstanding in connection with the November 2005 ASR for the nine months ended September 30, 2006. The remaining approximately three million shares relate to share-based compensation and are deemed to be outstanding in accordance with SFAS No. 128 for the purpose of calculating EPS for the nine months ended September 30, 2006.

⁽²⁾ Options to purchase 23,000 shares of PG&E Corporation common stock were excluded from the computation of diluted EPS for the three and nine months ended September 30, 2005 because the exercise prices of these options were greater than the average market price of PG&E Corporation common stock over these periods. All options to purchase shares of PG&E Corporation common stock were included in the computation of diluted EPS for the three and nine months ended September 30, 2006 because the option exercise prices of these options were lower than the average market price of PG&E Corporation common stock over these periods.

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

	Three Months Ended September 30, <u>2006</u>	Nine Months Ended September 30, <u>2006</u>	Year Ended December 31, <u>2005</u> <u>2004</u> <u>2003</u> <u>2002</u> <u>2001</u>				
Earnings:							
Net income	\$ 378	\$ 826	\$ 934	\$ 3,982	\$ 923	\$ 1,819	\$ 1,015
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	236	509	574	2,561	528	1,178	596
Net fixed charges	169	507	589	671	964	1,029	1,019
Total Earnings	<u>\$ 783</u>	<u>\$ 1,842</u>	<u>\$ 2,097</u>	<u>\$ 7,214</u>	<u>\$ 2,415</u>	<u>\$ 4,026</u>	<u>\$ 2,630</u>
Fixed Charges:							
Interest on short-term borrowings and long-term debt, net	\$ 160	\$ 488	\$ 573	\$ 682	\$ 947	\$ 996	\$ 981
Interest on capital leases	4	5	1	1	1	2	2
AFUDC debt	5	14	15	(12)	16	21	12
Earnings required to cover the preferred stock dividend and preferred security distribution requirements of majority owned trust	-	-	-	-	-	10	24
Total Fixed Charges	<u>\$ 169</u>	<u>\$ 507</u>	<u>\$ 589</u>	<u>\$ 671</u>	<u>\$ 964</u>	<u>\$ 1,029</u>	<u>\$ 1,019</u>
Ratios of Earnings to Fixed Charges	<u>4.63</u>	<u>3.63</u>	<u>3.56</u>	<u>10.75</u>	<u>2.51</u>	<u>3.91</u>	<u>2.58</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.

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, 2006	Nine Months Ended September 30, 2006	2005	Year Ended December 31,			
	2006	2006	2005	2004	2003	2002	2001
Earnings:							
Net income	\$ 378	\$ 826	\$ 934	\$ 3,982	\$ 923	\$ 1,819	\$ 1,015
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	236	509	574	2,561	528	1,178	596
Net fixed charges	169	507	589	671	964	1,029	1,019
Total Earnings	\$ 783	\$ 1,842	\$ 2,097	\$ 7,214	\$ 2,415	\$ 4,026	\$ 2,630
Fixed Charges:							
Interest on short-term borrowings and long-term debt, net	\$ 160	\$ 488	\$ 573	\$ 682	\$ 947	\$ 996	\$ 981
Interest on capital leases	4	5	1	1	1	2	2
AFUDC debt	5	14	15	(12)	16	21	12
Earnings required to cover the preferred stock dividend and preferred security distribution requirements of majority owned trust	-	-	-	-	-	10	24
Total Fixed Charges	169	507	589	671	964	1,029	1,019
Preferred Stock Dividends:							
Tax deductible dividends	3	9	12	9	9	9	9
Pre-tax earnings required to cover non-tax deductible preferred stock dividend requirements	-	2	13	34	27	28	27
Total Preferred Stock Dividends	3	11	25	43	36	37	36
Total Combined Fixed Charges and Preferred Stock Dividends	\$ 172	\$ 518	\$ 614	\$ 714	\$ 1,000	\$ 1,066	\$ 1,055
Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends	4.55	3.56	3.42	10.10	2.42	3.78	2.49

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.

Exhibit 31.1

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, 2006 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 8, 2006

/s/ 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, 2006 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 8, 2006

_____/s/ Christopher P. Johns
Christopher P. Johns
Senior Vice President, Chief Financial Officer and Treasurer

Exhibit 31.2

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

I, Thomas B. King, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarter ended September 30, 2006 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 8, 2006
King_____

_____/s/ Thomas B.

Thomas B. King
Chief Executive Officer

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 year ended September 30, 2006 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 8, 2006

Johns

/s/ Christopher P.

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

**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, 2006, 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) such Quarterly Report on Form 10-Q of PG&E Corporation for the quarter ended September 30, 2006, 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 such Quarterly Report on Form 10-Q of PG&E Corporation for the quarter ended September 30, 2006, fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

/s/ Christopher P. Johns

CHRISTOPHER P. JOHNS

Senior Vice President,

Chief Financial Officer and Treasurer

November 8, 2006

**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, 2006, I, Christopher P. Johns, Senior Vice President, Chief Financial Officer and Treasurer 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) such Quarterly Report on Form 10-Q of Pacific Gas and Electric Company for the quarter ended September 30, 2006, 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 such Quarterly Report on Form 10-Q of Pacific Gas and Electric Company for the quarter ended September 30, 2006, fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

/s/ Christopher P. Johns

CHRISTOPHER P. JOHNS

Senior Vice President, Chief Financial Officer
and Treasurer

November 8, 2006