

PG&E CORP

FORM 10-Q (Quarterly Report)

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Transition

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

(Mark One)

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

For the quarterly period ended June 30, 2005

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 twelve 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 an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Yes ☒

No ☐

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

Common Stock Outstanding, July 28, 2005:

PG&E Corporation

373,054,553 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 JUNE 30, 2005
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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		Six Months Ended	
	June 30,		June 30,	
	2005	2004	2005	2004
Operating Revenues				
Electric	\$ 1,780	\$ 2,063	\$ 3,439	\$ 3,851
Natural gas	718	686	1,727	1,617
Total operating revenues	2,498	2,749	5,166	5,468
Operating Expenses				
Cost of electricity	487	685	884	1,254
Cost of natural gas	347	278	967	857
Operating and maintenance	670	757	1,436	1,576
Recognition of regulatory assets	-	-	-	(4,900)
Depreciation, amortization and decommissioning	454	353	839	651
Reorganization professional fees and expenses	-	4	-	6
Total operating (gain) expenses	1,958	2,077	4,126	(556)
Operating Income	540	672	1,040	6,024
Reorganization interest income	-	-	-	8
Interest income	16	25	37	31
Interest expense	(131)	(176)	(292)	(406)
Other expense, net	(2)	(14)	(3)	(41)
Income Before Income Taxes	423	507	782	5,616
Income tax provision	156	135	297	2,211
Net Income	\$ 267	\$ 372	\$ 485	\$ 3,405
Weighted Average Common Shares Outstanding, Basic	370	397	379	395
Net Earnings Per Common Share, Basic	\$ 0.70	\$ 0.89	\$ 1.25	\$ 8.22
Net Earnings Per Common Share, Diluted	\$ 0.70	\$ 0.88	\$ 1.23	\$ 8.03
Dividends Declared Per Common Share	\$ 0.30	\$ -	\$ 0.60	\$ -

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions)	Balance At	
	June 30,	December 31,
	2005	2004
	(Unaudited)	
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 1,494	\$ 972
Restricted cash	1,659	1,980
Accounts receivable:		
Customers (net of allowance for doubtful accounts of \$91 million in 2005 and \$93 million in 2004)	2,029	2,085
Regulatory balancing accounts	859	1,021
Inventories:		

Gas stored underground	175	175
Materials and supplies	137	129
Prepaid expenses and other	72	46
Total current assets	6,425	6,408
Property, Plant and Equipment		
Electric	21,975	21,519
Gas	8,663	8,526
Construction work in progress	533	449
Other	15	15
Total property, plant and equipment	31,186	30,509
Accumulated depreciation	(11,891)	(11,520)
Net property, plant and equipment	19,295	18,989
Other Noncurrent Assets		
Regulatory assets	6,236	6,526
Nuclear decommissioning funds	1,659	1,629
Other	802	988
Total other noncurrent assets	8,697	9,143
TOTAL ASSETS	\$ 34,417	\$ 34,540

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)

	Balance At	
	June 30, 2005 (Unaudited)	December 31, 2004
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	\$ -	\$ 300
Long-term debt, classified as current	202	758
Rate reduction bonds, classified as current	290	290
Energy recovery bonds, classified as current	232	-
Accounts payable:		
Trade creditors	488	762
Disputed claims and customer refunds	1,810	2,142
Regulatory balancing accounts	1,150	369
Other	420	352
Interest payable	427	461
Income taxes payable	339	185
Deferred income taxes	357	394
Other	856	905
Total current liabilities	6,571	6,918
Noncurrent Liabilities		
Long-term debt	6,977	7,323
Rate reduction bonds	439	580
Energy recovery bonds	1,642	-
Regulatory liabilities	3,797	4,035
Asset retirement obligations	1,347	1,301
Deferred income taxes	3,457	3,531
Deferred tax credits	117	121
Preferred stock of subsidiary with mandatory redemption provisions (redeemable, 6.30% and 6.57%, no shares outstanding at June 30, 2005, 4,925,000 shares outstanding at December 31, 2004)	-	122
Other	1,720	1,690

Total noncurrent liabilities	19,496	18,703
Commitments and Contingencies (Notes 1, 2, 3, 4 and 7)		
Preferred Stock of Subsidiaries	286	286
Preferred Stock		
Preferred stock, no par value, 80,000,000 shares, \$100 par value, 5,000,000 shares, none issued	-	-
Common Shareholders' Equity		
Common stock, no par value, authorized 800,000,000 shares, issued 396,118,663 common and 1,390,388 restricted shares in 2005 and 417,014,431 common and 1,601,710 restricted shares in 2004	6,282	6,518
Common stock held by subsidiary, at cost, 24,665,500 shares	(718)	(718)
Unearned compensation	(28)	(26)
Accumulated earnings	2,533	2,863
Accumulated other comprehensive loss	(5)	(4)
Total common shareholders' equity	8,064	8,633
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	\$ 34,417	\$ 34,540

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)	(Unaudited)	
	Six Months Ended	
	June 30,	
	2005	2004
Cash Flows From Operating Activities		
Net income	\$ 485	\$ 3,405
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization and decommissioning	839	651
Recognition of regulatory assets	-	(4,900)
Deferred income taxes and tax credits, net	(115)	2,053
Other deferred charges and noncurrent liabilities	(75)	12
Tax benefit on employee stock option exercises	37	-
Gain on sale of assets	-	(18)
Net effect of changes in operating assets and liabilities:		
Short-term investments	(6)	-
Accounts receivable	56	(8)
Inventories	(8)	5
Accounts payable	(221)	170
Accrued taxes	153	284
Regulatory balancing accounts, net	565	(440)
Other working capital	(164)	560
Payments authorized by the bankruptcy court on amounts classified as liabilities subject to compromise	-	(1,022)
Other, net	37	(134)
Net cash provided by operating activities	1,583	618
Cash Flows From Investing Activities		
Capital expenditures	(803)	(737)
Net proceeds from sale of assets	17	25
Decrease (increase) in restricted cash	321	(1,741)
Other, net	12	(54)
Net cash used in investing activities	(453)	(2,507)
Cash Flows From Financing Activities		
Repayments under credit facilities and short-term borrowings	(300)	-

Proceeds from issuance of long-term debt, net of issuance costs of \$3 million in 2005 and \$153 million in 2004	451	6,892
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	(1,356)	(7,098)
Rate reduction bonds matured	(141)	(141)
Energy recovery bonds matured	(14)	-
Preferred stock with mandatory redemption provisions redeemed	(122)	(11)
Common stock issued	190	97
Common stock repurchased	(1,065)	-
Preferred dividends paid	(8)	(88)
Common stock dividends paid	(111)	-
Other	(6)	-
Net cash used in financing activities	(608)	(349)
Net change in cash and cash equivalents	522	(2,238)
Cash and cash equivalents at January 1	972	3,658
Cash and cash equivalents at June 30	\$ 1,494	\$ 1,420
Supplemental disclosures of cash flow information		
Cash received for:		
Reorganization interest income	\$ -	\$ 11
Cash paid for:		
Interest (net of amounts capitalized)	217	351
Income taxes paid, net	241	48
Reorganization professional fees and expenses	-	17
Supplemental disclosures of noncash investing and financing activities		
Common stock dividends declared but not yet paid	\$ 112	\$ -
Transfer of liabilities and other payables subject to compromise to operating assets and liabilities	-	(2,877)
Transfer of disputed claims and customer refunds and interest payable to accounts payable - regulatory balancing accounts	(378)	-

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(in millions)	(Unaudited)			
	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2005	2004	2005	2004
Operating Revenues				
Electric	\$ 1,780	\$ 2,063	\$ 3,439	\$ 3,851
Natural gas	718	686	1,727	1,617
Total operating revenues	2,498	2,749	5,166	5,468
Operating Expenses				
Cost of electricity	487	685	884	1,254
Cost of natural gas	347	278	967	857
Operating and maintenance	670	748	1,441	1,557
Recognition of regulatory assets	-	-	-	(4,900)
Depreciation, amortization and decommissioning	454	352	839	650
Reorganization professional fees and expenses	-	4	-	6
Total operating (gain) expenses	1,958	2,067	4,131	(576)
Operating Income	540	682	1,035	6,044
Reorganization interest income	-	-	-	8
Interest income	20	23	39	26
Interest expense	(124)	(158)	(278)	(372)
Other income, net	6	24	12	38

Income Before Income Taxes	442	571	808	5,744
Income tax provision	166	159	309	2,258
Net Income	276	412	499	3,486
Preferred dividend requirement	4	4	8	12
Income Available for Common Stock	\$ 272	\$ 408	\$ 491	\$ 3,474

See accompanying Notes to the Condensed Consolidated Financial Statements.

**PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS**

(in millions)	Balance At	
	June 30, 2005 (Unaudited)	December 31, 2004
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 1,140	\$ 783
Restricted cash	1,659	1,980
Accounts receivable:		
Customers (net of allowance for doubtful accounts of \$91 million in 2005 and \$93 million in 2004)	2,029	2,085
Related parties	2	2
Regulatory balancing accounts	859	1,021
Inventories:		
Gas stored underground and fuel oil	175	175
Materials and supplies	137	129
Prepaid expenses and other	68	43
Total current assets	6,069	6,218
Property, Plant and Equipment		
Electric	21,975	21,519
Gas	8,663	8,526
Construction work in progress	533	449
Total property, plant and equipment	31,171	30,494
Accumulated depreciation	(11,877)	(11,507)
Net property, plant and equipment	19,294	18,987
Other Noncurrent Assets		
Regulatory assets	6,236	6,526
Nuclear decommissioning funds	1,659	1,629
Other	755	942
Total other noncurrent assets	8,650	9,097
TOTAL ASSETS	\$ 34,013	\$ 34,302

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	
	June 30, 2005 (Unaudited)	December 31, 2004
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short term borrowings	\$ -	\$ 300

Long-term debt, classified as current	202	757
Rate reduction bonds, classified as current	290	290
Energy recovery bonds, classified as current	232	-
Accounts payable:		
Trade creditors	488	762
Disputed claims and customer refunds	1,810	2,142
Related parties	28	20
Regulatory balancing accounts	1,150	369
Other	408	337
Interest payable	427	461
Income taxes payable	290	102
Deferred income taxes	334	377
Other	714	869
Total current liabilities	6,373	6,786
Noncurrent Liabilities		
Long-term debt	6,697	7,043
Rate reduction bonds	439	580
Energy recovery bonds	1,642	-
Regulatory liabilities	3,797	4,035
Asset retirement obligations	1,347	1,301
Deferred income taxes	3,573	3,629
Deferred tax credits	117	121
Preferred stock with mandatory redemption provisions (redeemable, 6.30% and 6.57%, no shares outstanding)	-	122
Other	1,589	1,555
Total noncurrent liabilities	19,201	18,386
Commitments and Contingencies (Notes 1, 2, 3, 4 and 7)		
Shareholders' Equity		
Preferred stock without mandatory redemption provisions:		
Nonredeemable, 5% to 6%, outstanding 5,784,825 shares	145	145
Redeemable, 4.36% to 7.04%, outstanding 5,973,456 shares	149	149
Common stock, \$5 par value, authorized 800,000,000 shares, issued 299,291,477 shares	1,496	1,606
Common stock held by subsidiary, at cost, 19,481,213 shares	(475)	(475)
Additional paid-in capital	1,901	2,041
Reinvested earnings	5,228	5,667
Accumulated other comprehensive loss	(5)	(3)
Total shareholders' equity	8,439	9,130
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	\$ 34,013	\$ 34,302

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)	(Unaudited)	
	Six Months Ended	
	June 30,	
	2005	2004
Cash Flows From Operating Activities		
Net income	\$ 499	\$ 3,486
Adjustments to reconcile net income to net cash provided by		
operating activities:		
Depreciation, amortization and decommissioning	839	650
Recognition of regulatory assets	-	(4,900)
Deferred income taxes and tax credits, net	(103)	2,105
Other deferred charges and noncurrent liabilities	(83)	79

Gain on sale of assets	(1)	(18)
Net effect of changes in operating assets and liabilities:		
Accounts receivable	56	(35)
Inventories	(8)	5
Accounts payable	(222)	170
Accrued taxes	188	288
Regulatory balancing accounts, net	565	(440)
Other working capital	(144)	287
Payments authorized by the bankruptcy court on amounts classified as liabilities subject to compromise	-	(1,022)
Other, net	18	(128)
Net cash provided by operating activities	1,604	527
Cash Flows From Investing Activities		
Capital expenditures	(803)	(737)
Net proceeds from sale of assets	17	25
Decrease (increase) in restricted cash	321	(1,741)
Other, net	12	(54)
Net cash used in investing activities	(453)	(2,507)
Cash Flows From Financing Activities		
Repayments under credit facilities and short-term borrowings	(300)	-
Proceeds from issuance of long-term debt, net of issuance costs of \$3 million in 2005 and \$153 million in 2004	451	6,892
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	(1,354)	(7,098)
Rate reduction bonds matured	(141)	(141)
Energy recovery bonds matured	(14)	-
Common stock dividends paid	(220)	-
Preferred dividends paid	(8)	(88)
Preferred stock with mandatory redemption provisions redeemed	(122)	(11)
Common stock repurchased	(960)	-
Net cash used in financing activities	(794)	(446)
Net change in cash and cash equivalents	357	(2,426)
Cash and cash equivalents at January 1	783	2,979
Cash and cash equivalents at June 30	\$ 1,140	\$ 553
Supplemental disclosures of cash flow information		
Cash received for:		
Reorganization interest income	\$ -	\$ 11
Cash paid for:		
Interest (net of amounts capitalized)	204	315
Income taxes paid, net	237	-
Reorganization professional fees and expenses	-	17
Supplemental disclosures of noncash investing and financing activities		
Equity contribution for settlement of POR payable	\$ -	\$ (128)
Transfer of liabilities and other payables subject to compromise to operating assets and liabilities	-	(2,877)
Transfer of disputed claims and customer refunds and interest payable to accounts payable - regulatory balancing accounts	(378)	-

See accompanying Notes to the Condensed Consolidated Financial Statements.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1: GENERAL

Organization and Basis of Presentation

PG&E Corporation, incorporated in California in 1995, is an energy-based holding company that 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, electricity 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. The Utility, incorporated in California in 1905, is the predecessor of PG&E Corporation.

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 variable interest entities for which it is subject to a majority of the risk of loss or gain. 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 generally accepted accounting principles 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. Accordingly, they may not contain all of the information and footnotes required by GAAP for complete financial statements. Both PG&E Corporation's and the Utility's Condensed Consolidated Balance Sheets at December 31, 2004, were derived from the audited Consolidated Balance Sheets included in their combined 2004 Annual Report on Form 10-K, or Annual Report, filed with the Securities and Exchange Commission, or SEC.

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, environmental remediation liabilities, pension liabilities, mark-to-market accounting under Statement of Financial Accounting Standards, or SFAS, No. 133 "Accounting for Derivative Instruments and Hedging Activities," as amended, or SFAS No. 133, 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. As these estimates and assumptions involve judgments based 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. 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. 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.

During the Utility's proceeding under Chapter 11 of the U.S. Bankruptcy Code, or Chapter 11, PG&E Corporation's and the Utility's Consolidated Financial Statements were presented in accordance with the American Institute of Certified Public Accountants' Statement of Position 90-7, "Financial Reporting by Entities in Reorganization Under the Bankruptcy Code," or SOP 90-7. Under SOP 90-7, professional fees and expenses directly related to the Utility's Chapter 11 proceeding and interest income on funds accumulated during the Chapter 11 proceedings were reported separately as reorganization items. The Utility discontinued the application of SOP 90-7 upon its emergence from Chapter 11 on April 12, 2004 when the Utility's plan of reorganization under Chapter 11 became effective, or the Effective Date. As discussed below, in Note 2, the U.S. Bankruptcy Court for the Northern District of California, which oversaw the Utility's Chapter 11 proceeding, retains jurisdiction, among other things, to resolve the remaining disputed claims 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 included in their combined 2004 Annual Report.

Earnings Per Common Share

Earnings per common share 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 shareholders and participating securities. PG&E Corporation's \$280 million of 9.50% Convertible Subordinated Notes due 2010, or Convertible Subordinated Notes, are entitled to receive (non-cumulative) dividend payments without 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.

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

(in millions, except per share amounts)	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2005	2004	2005	2004
Net income	\$ 267	\$ 372	\$ 485	\$ 3,405

Less: distributed earnings to common shareholders	112	-	223	-
Undistributed earnings	155	372	262	3,405

Common shareholders earnings

Basic

Distributed earnings to common shareholders	\$ 112	\$ -	\$ 223	\$ -
Undistributed earnings allocated to common shareholders	147	355	249	3,249
Total common shareholders earnings, basic	\$ 259	\$ 355	\$ 472	\$ 3,249

Diluted

Distributed earnings to common shareholders	\$ 112	\$ -	\$ 223	\$ -
Undistributed earnings allocated to common shareholders	148	356	250	3,252
Total common shareholders earnings, diluted	\$ 260	\$ 356	\$ 473	\$ 3,252

Weighted average common shares outstanding, basic

9.50% Convertible Subordinated Notes	19	19	19	19
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Weighted average common shares outstanding and participating securities, basic	389	416	398	414
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Weighted average common shares outstanding, basic	370	397	379	395
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Employee stock compensation, restricted stock, accelerated share repurchase agreement and PG&E Corporation shares held by grantor trusts	5	7	5	7
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PG&E Corporation warrants	-	2	-	3
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Rounding	(1)	-	(1)	-
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Weighted average common shares outstanding, diluted	374	406	383	405
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9.50% Convertible Subordinated Notes	19	19	19	19
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Weighted average common shares outstanding and participating securities, diluted	393	425	402	424
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Net earnings per common share, basic

Distributed earnings, basic	\$ 0.30	\$ -	\$ 0.59	\$ -
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Undistributed earnings, basic	0.40	0.89	0.66	8.22
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Total	\$ 0.70	\$ 0.89	\$ 1.25	\$ 8.22
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Net earnings per common share, diluted

Distributed earnings, diluted	\$ 0.30	\$ -	\$ 0.58	\$ -
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Undistributed earnings, diluted	0.40	0.88	0.65	8.03
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Total	\$ 0.70	\$ 0.88	\$ 1.23	\$ 8.03
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The following options to purchase PG&E Corporation common shares were outstanding, but not included in the computation of diluted earnings per share because the option exercise prices were greater than the average market price: six months ended June 30, 2005 -- 6,500, six months ended June 30, 2004 -- 7,874,615, three months ended June 30, 2005 -- 6,500, and three months ended June 30, 2004 -- 8,235,055.

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

Consolidation of Variable Interest Entities

An entity is a variable interest entity, or VIE, if it does not have sufficient equity investment at risk, or if the holders of the entity's equity instruments lack the essential characteristics of a controlling financial interest. The Financial Accounting Standards Board, or FASB, Interpretation No. 46, "Consolidation of Variable Interest Entities," or FIN 46R, requires that the company that is subject to a majority of the risk of loss from a VIE's activities, or is entitled to receive a majority of the entity's residual returns, or both, consolidate the VIE. A company that consolidates a VIE is called the primary beneficiary.

PG&E Corporation and the Utility adopted FIN 46R on January 1, 2004. The adoption of FIN 46R did not have an impact on net income.

Low-Income Housing Partnerships

The Utility invests in low-income housing partnerships, or LIHPs. The entities were formed to invest in low-income housing projects sponsored by non-profit organizations in the state of California. The Utility is the primary beneficiary of one LIHP, resulting in its consolidation, and an increase in total assets and total liabilities of \$10 million in PG&E Corporation's and the Utility's Consolidated Balance Sheets. The consolidated LIHP has issued debt in the amount of \$4 million, which is secured by assets of the partnership, totaling \$25 million, and the Utility's commitment to make capital infusions of approximately \$9 million over the next five years.

The Utility is not considered to be the primary beneficiary of any other LIHPs. The maximum exposure to loss from its investment in unconsolidated LIHPs is the Utility's investment of \$4 million at June 30, 2005.

Power Purchase Agreements

The nature of power purchase agreements is such that the Utility could have a significant variable interest in a power purchase agreement counterparty if that entity is a VIE owning one plant that sells substantially all of its output to the Utility, and the contract price for power is correlated with the plant's variable costs of production. The Utility has determined that none of its current power purchase agreements represent significant variable interests. The FASB added a project to its agenda in March 2005 to review how companies determine whether an arrangement is a variable interest. Their findings could impact how the determination is applied to the Utility's power purchase agreements in the future.

Adoption of New Accounting Policies and Summary of Significant Accounting Policies

The accounting policies used by PG&E Corporation and the Utility include those necessary for rate-regulated enterprises, which reflect the ratemaking policies of the California Public Utilities Commission, or CPUC, and the Federal Energy Regulatory Commission, or FERC.

Accounting Requirements Related to the Tax Deduction provided by the American Jobs Creation Act of 2004

In December 2004, FASB issued Staff Position FAS No. 109-1, "Application of FASB Statement No. 109, 'Accounting for Income Taxes,' to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004," or FSP 109-1. FSP 109-1 indicates that the tax deduction on qualified production activities should be accounted for as a special deduction rather than as a rate reduction. Any benefit from the deduction on qualified production activities is to be reported during the year in which the deduction is claimed. FSP 109-1 was effective upon issuance. The adoption of FSP 109-1 did not have a material impact on the Consolidated Financial Statements of PG&E Corporation or the Utility.

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. These services are priced either at the fully loaded cost (i.e., direct costs and allocations of overhead costs) or at the higher 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 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 purchases natural gas transportation services from Gas Transmission Northwest Corporation, or GTNW, formerly known as PG&E Gas Transmission, Northwest Corporation. GTNW is no longer a related party after the cancellation of PG&E Corporation's equity interest in National Energy & Gas Transmission, Inc., or NEGT, on the effective date of its plan of reorganization, October 29, 2004. Through July 7, 2003, all significant intercompany transactions with NEGT and its subsidiaries were eliminated in consolidation; therefore, no profit or loss resulted from these transactions. Beginning July 8, 2003, the Utility's transactions with NEGT are no longer eliminated in consolidation. The Utility's significant related party transactions and related receivable (payable) balances were as follows:

(in millions)	Three Months Ended		Six Months Ended		Receivable (Payable)	
	June 30,		June 30,		Balance Outstanding at	
	2005	2004	2005	2004	June 30, 2005	December 31, 2004
Utility revenues from:						
Administrative services provided to PG&E Corporation	\$ 1	\$ 2	\$ 2	\$ 4	\$ 1	\$ 1
Utility expenses from:						
Administrative services received from PG&E Corporation	\$ 24	\$ 20	\$ 49	\$ 42	\$ (28)	\$ (20)
Interest accrued on pre-petition liabilities due to PG&E Corporation	-	-	-	2	-	-
Natural gas transportation services received from GTNW	-	14	-	29	-	-

Regulation and Statement of Financial Accounting Standards No. 71

PG&E Corporation and the Utility account for the financial effects of regulation in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," as amended, or SFAS No. 71. SFAS No. 71 applies to regulated entities whose rates are designed to recover the costs of providing service. The Utility is regulated by the CPUC, the FERC and the Nuclear Regulatory Commission, or NRC, among others. SFAS No. 71 applies to all of the Utility's operations except for the operations of a natural gas pipeline.

SFAS No. 71 provides for recording regulatory assets and liabilities when certain conditions are met. Regulatory assets represent the capitalization of incurred costs that would otherwise be charged to expense when it is probable that the incurred costs will be included for ratemaking purposes in the future. Amortization of regulatory assets is charged to expense during the period that the costs are reflected in regulated revenues. Regulatory liabilities represent rate actions of a regulator that will result in amounts that are to be credited to customers through the ratemaking process.

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 the Utility's competitive position, the related regulatory assets and liabilities are written off.

Regulatory Assets

Regulatory assets comprise the following:

(in millions)	Balance At	
	June 30, 2005	December 31, 2004
Settlement Regulatory Asset	\$ 1,239	\$ 3,188
Energy recovery bond regulatory asset	1,806	-
Utility retained generation regulatory assets	1,140	1,181
Rate reduction bond assets	613	741
Regulatory assets for deferred income tax	510	490
Unamortized loss, net of gain, on reacquired debt	334	345
Environmental compliance costs	242	192
Regulatory assets associated with plan of reorganization	167	182
Post-transition period contract termination costs	137	142
Other, net	48	65
Total regulatory assets	\$ 6,236	\$ 6,526

In light of the satisfaction of various conditions to the implementation of the Utility's plan of reorganization, the accounting probability standard required to be met under SFAS No. 71 in order for the Utility to recognize the regulatory assets provided under the Settlement Agreement (as described in Note 2) was met as of March 31, 2004. Therefore, the Utility recorded the \$3.7 billion, pre-tax (\$2.2 billion, after-tax), regulatory asset established under the Settlement Agreement, or the Settlement Regulatory Asset, and \$1.2 billion, pre-tax (\$0.7 billion, after-tax), for the Utility retained generation regulatory assets in the first quarter of 2004 (see Note 2 for further discussion). As of December 31, 2004, the Utility had recorded pre-tax offsets to the Settlement Regulatory Asset of approximately \$309 million (\$183 million, after-tax) for supplier settlements and approximately \$233 million (\$138 million, after-tax) for amortization of the Settlement Regulatory Asset. For the six months ended June 30, 2005, the Utility recorded amortization of the Settlement Regulatory Asset of approximately \$76 million (\$45 million, after-tax).

On February 10, 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 series of energy recovery bonds, or ERBs, for approximately \$1.9 billion to refinance the remaining after-tax balance of the Settlement Regulatory Asset. As a result of the issuance of ERBs, the pre-tax Settlement Regulatory Asset was reduced to approximately \$1.3 billion (representing the deferred tax liability associated with the collection of the revenues for the ERBs) and the Utility has recorded a regulatory asset related to the ERBs of approximately \$1.9 billion. For the six months ended June 30, 2005, the Utility recorded amortization of the energy recovery bond regulatory asset of approximately \$68 million.

The Utility's rate reduction bond asset represents electric industry restructuring costs that the Utility expects to collect over the life of the bonds. 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. The regulatory asset related to unamortized loss, net of gain, on reacquired debt represents costs on debt reacquired or redeemed prior to maturity with associated discount and debt issuance costs. Environmental compliance costs are costs incurred by the Utility for environmental remediation. Regulatory assets associated with the 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 post-transition period contract termination costs represent amounts the Utility incurred in terminating a 30-year power purchase agreement. These regulatory assets

are recoverable from customers in future rates.

In general, the Utility does not earn a return on regulatory assets where the related costs do not accrue interest. Accordingly, the only regulatory asset 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.

The Settlement Agreement authorizes the Utility to earn an 11.22% rate of return on equity on its rate base, including the after-tax amount of the Settlement Regulatory Asset and the retained generation regulatory assets. Since the refinancing of the remaining unamortized after-tax balance of the Settlement Regulatory Asset on February 10, 2005 through the issuance of the first series of ERBs, the Utility no longer earns this 11.22% rate of return on the Settlement Regulatory Asset as it is no longer a part of rate base.

Regulatory Liabilities

Regulatory liabilities comprise the following:

(in millions)	Balance At	
	June 30, 2005	December 31, 2004
Cost of removal obligation	\$ 2,059	\$ 1,990
Asset retirement costs	692	700
Employee benefit plans	592	687
Public purpose programs	192	191
Rate reduction bonds	175	182
Other	87	285
Total regulatory liabilities	\$ 3,797	\$ 4,035

The Utility's regulatory liabilities related to costs of removal 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 nuclear and fossil decommissioning obligations in accordance with GAAP applicable to non-regulated entities under SFAS No. 143, "Accounting for Asset Retirement Obligations," or SFAS No. 143, and the amounts recognized for ratemaking purposes. The Utility's regulatory liabilities related to employee benefit plan expenses represent the cumulative differences between expenses recognized for financial accounting purposes and expenses recognized for ratemaking purposes. These balances will be charged against expense to the extent that future financial accounting expenses exceed amounts recoverable for regulatory 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 rate reduction bonds represents the deferral of over-collected revenue associated with the rate reduction bonds that the Utility expects to return to customers in the future.

Regulatory Balancing Accounts

Sales balancing accounts accumulate differences between revenues and the Utility's authorized revenue requirements. Cost balancing accounts accumulate differences between incurred costs and revenues. 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 regulatory balancing accounts accumulate balances until they are refunded to or received from the Utility's customers through authorized rate adjustments.

The Utility expects to collect from or refund to its customers the balances included in current balancing accounts receivable and payable within the next twelve months. Regulatory balancing accounts that the Utility does not expect to collect or refund in the next twelve months are included in non-current regulatory assets and liabilities.

As a result of settlements that the Utility has entered into with various power suppliers (see further discussion in Note 7 of the Notes to the Consolidated Financial Statements) and other activities related to the ERBs, the balance in the Energy Recovery Bond Balancing Account, or the ERBBA, which tracks recovery of customer costs and benefits related to the ERBs, is approximately \$365 million as of June 30, 2005.

Stock-Based Compensation

PG&E Corporation and the Utility apply the intrinsic-value method prescribed in Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees," in accounting for employee stock-based compensation, as allowed by SFAS No. 123, "Accounting for Stock-Based Compensation," or SFAS No. 123, as amended by SFAS No. 148, "Accounting for Stock-Based Compensation - Transition and Disclosure, an Amendment of FASB Statement No. 123," or SFAS No. 148. Under the intrinsic-value method, PG&E Corporation and the Utility do not recognize any compensation expense for stock options, as the exercise price is equal to the fair market value

of a share of PG&E Corporation common stock at the time the options are granted.

The tables below show the effect on net income and earnings per common share for PG&E Corporation and the Utility had it elected to account for its stock-based compensation plans using the fair-value method under SFAS No. 123 for the three and six months ended June 30, 2005 and 2004:

(in millions, except per share amounts)	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2005	2004	2005	2004
Net earnings:				
As reported	\$ 267	\$ 372	\$ 485	\$ 3,405
Deduct: Total stock-based employee compensation expense determined under the fair value based method for all awards, net of related tax effects	3	4	6	9
Pro forma	\$ 264	\$ 368	\$ 479	\$ 3,396
Basic earnings per common share:				
As reported	\$ 0.70	\$ 0.89	\$ 1.25	\$ 8.22
Pro forma	0.69	0.88	1.23	8.20
Diluted earnings per common share:				
As reported	0.70	0.88	1.23	8.03
Pro forma	0.69	0.87	1.22	8.05

If compensation expense had been recognized using the fair value-based method under SFAS No. 123, the Utility's pro forma consolidated earnings would have been as follows:

(in millions)	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2005	2004	2005	2004
Net earnings:				
As reported	\$ 272	\$ 408	\$ 491	\$ 3,474
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	2	2	4	4
Pro forma	\$ 270	\$ 406	\$ 487	\$ 3,470

Restricted Stock

At June 30, 2005, a total of 2,418,760 shares of restricted PG&E Corporation common stock had been awarded to eligible employees of PG&E Corporation and its subsidiaries, of which 1,597,920 shares were awarded to Utility employees. PG&E Corporation awarded 329,840 shares of restricted common stock during the six months ended June 30, 2005, of which 241,790 shares were awarded to Utility employees.

The restricted shares are held in an escrow account. The shares become available to the employees as the restrictions lapse. Dividends payable with respect to restricted shares are not paid until the restrictions lapse.

For restricted stock granted in 2003, the restrictions on 80% of the shares lapse automatically over a period of four years at the rate of 20% per year. The compensation expense for these shares remains fixed at the value of the stock at grant date. Restrictions on the remaining 20% of the shares will lapse at a rate of 5% per year if PG&E Corporation is in the top quartile of its comparator group as measured by annual total shareholder return for each year ending immediately before each annual lapse date. The compensation expense recognized for these shares is variable, and changes with the common stock's market price. As the performance criteria for 2004 were not met, 91,017 shares of restricted stock were forfeited.

Restricted stock awards after 2003 do not contain performance criteria. The restrictions lapse ratably over four years, from the date of award, subject to forfeiture if employment is terminated before the annual vesting date. All restricted shares are also subject to accelerated vesting in certain circumstances, including death, disability, and change in control.

Compensation expense associated with all the shares is recognized on a quarterly basis, by amortizing the unearned compensation related to that period. Total compensation expense resulting from the issuance of restricted shares, as reflected on PG&E Corporation's Condensed Consolidated Statements of Income, was approximately \$3 million for the three months ended June 30, 2005 and approximately \$3

million for the three months ended June 30, 2004, of which approximately \$2 million for the three months ended June 30, 2005 and approximately \$2 million for the three months ended June 30, 2004 was recognized by the Utility. The comparable amount for the six months ended June 30, 2005 was approximately \$6 million and approximately \$6 million for the six months ended June 30, 2004, of which approximately \$4 million for the six months ended June 30, 2005 and approximately \$4 million for the six months ended June 30, 2004 was recognized by the Utility. The total unamortized balance of unearned compensation resulting from the issuance of restricted shares, as reflected as a reduction in common shareholders' equity on PG&E Corporation's Condensed Consolidated Balance Sheets was approximately \$28 million at June 30, 2005 and approximately \$26 million at December 31, 2004.

Comprehensive Income (Loss)

PG&E Corporation's and the Utility's comprehensive income (loss) consists principally of changes in the market value of certain cash flow hedges under SFAS No. 133, and the effects of the remeasurement of the Utility's defined benefit pension plan.

(in millions)	PG&E Corporation		Utility	
	2005	2004	2005	2004
Three months ended June 30				
Comprehensive income	\$ 267	\$ 372	\$ 272	\$ 408
Six months ended June 30				
Net income available for common stock	\$ 485	\$ 3,405	\$ 491	\$ 3,474
Net gain in other comprehensive income from current period hedging transactions and price changes in accordance with SFAS No. 133 (net of income tax expense of \$2 million in 2004)	-	3	-	3
Minimum pension liability adjustment (net of income tax benefit of \$2 million in 2005)	(1)	-	(2)	-
Other	-	1	-	-
Comprehensive income (loss)	\$ 484	\$ 3,409	\$ 489	\$ 3,477

PG&E Corporation and the Utility did not have any other comprehensive income activity for the three months ended June 30, 2005 and June 30, 2004.

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) reports a measure for accumulated changes in equity of an enterprise that results 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	Foreign Currency Translation Adjustment	Minimum Pension Liability Adjustment	Other	Accumulated Other Comprehensive Income (Loss)
Balance at December 31, 2003	\$ (81)	\$ -	\$ (4)	\$ -	\$ (85)
Period change in:					
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133	3	-	-	-	3
Other	-	-	-	1	1
Balance at June 30, 2004	(78)	-	(4)	1	(81)
Balance at December 31, 2004	(1)		(4)	1	(4)
Period change in:					
Minimum pension liability adjustment	-	-	(1)	-	(1)
Other	1	-	-	(1)	-
Balance at June 30, 2005	\$ -	\$ -	\$ (5)	\$ -	\$ (5)

Accumulated other comprehensive income (loss) included losses related to discontinued operations of approximately \$77 million at December 31, 2003. During the fourth quarter of 2004, the remaining losses of approximately \$77 million included in accumulated other comprehensive income (loss) were recognized in connection with PG&E Corporation's elimination of its equity interest in NEGTEC. Excluding the activity related to NEGTEC, there was no material difference between PG&E Corporation's and the Utility's accumulated other comprehensive income (loss).

There were no changes in PG&E Corporation's or the Utility's accumulated other comprehensive income (loss) components for the three months ended June 30, 2005 and June 30, 2004.

Pension and Other Postretirement Benefits

PG&E Corporation and its subsidiaries provide non-contributory defined benefit pension plans 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 its subsidiaries use a December 31 measurement date for all of its 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 six month periods ended June 30, 2005 and 2004 are as follows:

PG&E Corporation

(in millions)	Pension Benefits		Other Benefits	
	Three Months Ended		Three Months Ended	
	June 30,		June 30,	
	2005	2004	2005	2004
Service cost for benefits earned	\$ 56	\$ 47	\$ 9	\$ 9
Interest cost	125	118	20	23
Expected return on plan assets	(151)	(142)	(21)	(19)
Amortization of transition obligation	-	2	6	6
Amortization of prior service cost	14	13	3	3
Amortization of unrecognized loss	6	-	-	-
Net periodic benefit cost	\$ 50	\$ 38	\$ 17	\$ 22

(in millions)	Pension Benefits		Other Benefits	
	Six Months Ended		Six Months Ended	
	June 30,		June 30,	
	2005	2004	2005	2004
Service cost for benefits earned	\$ 112	\$ 93	\$ 17	\$ 18
Interest cost	249	236	40	44
Expected return on plan assets	(301)	(282)	(43)	(38)
Amortization of transition obligation	-	3	13	13
Amortization of prior service cost	27	26	6	7
Amortization of unrecognized loss	13	-	-	-
Net periodic benefit cost	\$ 100	\$ 76	\$ 33	\$ 44

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

Under SFAS No. 71, regulatory adjustments are recorded in the Consolidated Statements of Income and 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, which is based on a funding approach.

PG&E Corporation and the Utility expect to contribute approximately \$20 million for Pension Benefits to fund voluntary retirement program obligations and approximately \$68 million for Other Benefits in 2005. These anticipated contributions are consistent with PG&E Corporation's and the Utility's funding policy, which is to contribute amounts that are tax deductible, consistent with applicable regulatory decisions and sufficient to meet minimum funding requirements. None of these benefit plans are subject to a minimum funding requirement in 2005. The Utility's pension benefit plans met all the funding requirements under the Employee Retirement Income Security Act of 1974, as amended.

Accounting Pronouncements Issued But Not Yet Adopted

Share-Based Payment Transactions

In December 2004, the FASB issued Statement No. 123 (revised December 2004), "Share-Based Payment," or SFAS No. 123R. SFAS No. 123R requires that the cost resulting from all share-based payment transactions be recognized in the financial statements and establishes a fair-value measurement objective in determining the value of such a cost. On April 14, 2005, the SEC amended the compliance date and allowed public companies with calendar year-ends to adopt SFAS No. 123R in the first quarter of 2006. PG&E Corporation and the Utility are currently evaluating the impact of SFAS No. 123R on their Consolidated Financial Statements.

Conditional Asset Retirement Obligations

In March 2005, the FASB issued Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations - an interpretation of FASB Statement No. 143," or FIN 47. FIN 47 clarifies that a conditional asset retirement obligation refers to a legal obligation to perform an asset retirement activity. Accordingly, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the obligation can be reasonably estimated. FIN 47 will be effective for the fourth quarter of 2005. PG&E Corporation and the Utility are currently evaluating the impact of FIN 47 on their Consolidated Financial Statements.

Accounting Changes and Error Corrections

In May 2005, the FASB issued FASB Statement No. 154, "Accounting Changes and Error Corrections Disclosure," or SFAS No. 154. SFAS No. 154 replaces APB Opinion No. 20, "Accounting Changes," or APB No. 20, and FASB Statement No. 3, "Reporting Accounting Changes in Interim Financial Statements," or SFAS No. 3. SFAS No. 154 requires retrospective application to prior periods' financial statements of changes in accounting principle unless it is impracticable. This Statement applies to all voluntary changes in accounting principle. SFAS No. 154 also requires that a change in depreciation, amortization, or depletion method for long-lived, nonfinancial assets be accounted for as a change in accounting estimate affected by a change in accounting principle. SFAS No. 154 is effective for the first quarter of 2006. PG&E Corporation and the Utility are currently evaluating the impacts of SFAS No. 154 on their Consolidated Financial Statements.

Restricted Cash Classification on Statement of Cash Flows

PG&E Corporation and the Utility have changed the classification of changes in certain restricted cash balances in their Condensed Consolidated Statements of Cash Flows for the six months ended June 30, 2005, to present such changes as an investing activity. These changes in restricted cash balances were previously presented as an operating activity. In the accompanying Condensed Consolidated Statements of Cash Flows for the six months ended June 30, 2004, PG&E Corporation and the Utility have reclassified changes in restricted cash balances to be consistent with the 2005 presentation, which resulted in a \$93 million increase in investing cash flows and a corresponding decrease in operating cash flows from the amounts previously reported by both PG&E Corporation and the Utility.

NOTE 2: THE UTILITY'S EMERGENCE FROM CHAPTER 11

As a result of the California energy crisis, the Utility filed a voluntary petition for relief under the provisions of Chapter 11 on April 6, 2001. The Utility retained control of its assets and was authorized to operate its business as a debtor-in-possession during its Chapter 11 proceeding. PG&E Corporation and the subsidiaries of the Utility, including PG&E Funding LLC, (which issued rate reduction bonds) and PG&E Holdings LLC (which holds stock of the Utility), were not included in the Utility's Chapter 11 proceeding.

On April 12, 2004, the Utility emerged from Chapter 11 when its plan of reorganization became effective, or the Effective Date. The plan of reorganization incorporated the terms of the Settlement Agreement approved by the CPUC on December 18, 2003, and entered into among the CPUC, the Utility and PG&E Corporation on December 19, 2003, to resolve the Utility's Chapter 11 proceeding. 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. In addition, the bankruptcy court retains jurisdiction to resolve remaining disputed claims.

In light of the satisfaction of various conditions to the implementation of the plan of reorganization, the accounting probability standard required to be met under SFAS No. 71, in order for the Utility to recognize the regulatory assets provided under the Settlement Agreement was met as of March 31, 2004. Therefore, the Utility recorded the \$2.2 billion, after-tax (\$3.7 billion, pre-tax) Settlement Regulatory Asset, and \$0.7 billion, after-tax (\$1.2 billion, pre-tax), for the Utility retained generation regulatory assets. Refer to the 2004 Annual Report for further discussion of the Settlement Agreement. On February 10, 2005, the Utility refinanced the remaining unamortized after-tax portion of the Settlement Regulatory Asset as discussed in Note 4.

As of June 30, 2005, the Utility had accrued approximately \$1.3 billion for remaining net disputed claims, consisting of approximately \$1.8 billion of accounts payable-disputed claims primarily payable to the California Independent System Operator, or ISO, and the Power Exchange, or the PX, offset by an accounts receivable amount from the ISO and the PX of approximately \$0.5 billion. At December 31, 2004, the Utility had accrued approximately \$2.1 billion for remaining net disputed claims. Since December 31, 2004, the Utility has made payments to creditors of approximately \$6 million in settlement of disputed claims and, as a result of settlements reached with creditors, has reduced the disputed claims balance by approximately \$325 million. The Utility held \$1.4 billion in escrow for the payment of the remaining disputed claims as of June 30, 2005. Upon resolution of these claims and under the terms of the Settlement Agreement, any refunds, claims offsets or other credits that the Utility receives from energy suppliers will be returned to customers. With the approval of the bankruptcy court, the Utility has withdrawn certain amounts from the escrow in connection with settlements with certain ISO and PX sellers.

On June 13, 2005, the California Court of Appeal summarily denied the petitions for review of the CPUC's order approving the Settlement Agreement and order denying rehearing of its approval order that had been filed by the City and County of San Francisco, or CCSF, and Aglet Consumer Alliance, or Aglet. CCSF and Aglet have not appealed the appellate court's denial of their petitions and the time period within which an appeal could be filed has elapsed.

In addition, two former CPUC commissioners who did not vote to approve the Settlement Agreement filed an appeal of the bankruptcy court's confirmation order with the U.S. District Court for the Northern District of California, or the District Court. On July 15, 2004, the District Court dismissed their appeal. The former commissioners have appealed the District Court's order with the U.S. Court of Appeals for the Ninth Circuit, or Ninth Circuit. Briefing is complete, and the Ninth Circuit is likely to schedule oral arguments on the appeal by the end of the year. On April 12, 2005, the District Court entered an order dismissing a second appeal of the confirmation order that had been filed by the City of Palo Alto, but which the City of Palo Alto subsequently had agreed to dismiss voluntarily.

PG&E Corporation and the Utility believe the former commissioners' appeal of the confirmation order is without merit and will be rejected. If the bankruptcy court's confirmation order or the Settlement Agreement is overturned or modified on appeal, PG&E Corporation's and the Utility's financial condition and results of operations, and the Utility's ability to pay dividends or otherwise make distributions to PG&E Corporation, could be materially adversely affected.

NOTE 3: DEBT

Long-Term Debt

The following table summarizes PG&E Corporation's and the Utility's long-term debt that matures in one year or more from the date of issuance:

(in millions)	Balance At	
	June 30, 2005	December 31, 2004
PG&E Corporation		
Convertible subordinated notes, 9.50%, due 2010	\$ 280	\$ 280
Other long-term debt	-	1
Less: current portion	-	(1)
	280	280
Utility		
First mortgage bonds/senior notes		
Floating rate and 3.60% to 6.05% bonds, due 2006-2034	5,300	6,200
Unamortized discount, net of premium	(17)	(17)
Total first mortgage bonds/senior notes	5,283	6,183
Pollution control bond loan agreements, variable rates, due 2026	614	614
Pollution control bond loan agreement, 5.35%, due 2016	200	200
Pollution control bond loan agreements, 3.50%, due 2007	345	345
Pollution control bond loan agreements, variable rates, due 2016-2026	454	-
Pollution control bond reimbursement obligations, variable rates, due 2005	-	454
Other	3	4
Less: current portion	(202)	(757)
	6,697	7,043
Total consolidated long-term debt, net of current portion	\$ 6,977	\$ 7,323

Other Long Term Debt Guarantees ⁽¹⁾

(in millions)

Utility			At June 30, 2005	
Facility	Series	Termination Date	Commitment	Outstanding
Pollution control bond bank reimbursement agreements	96 C, E, F, 97 B	April 2010	\$ 620	\$ 620

Pollution control bond -- bond insurance reimbursement agreements	96A	December 2016	(2)	200	200
Pollution control bond -- bond insurance reimbursement agreements	2004 A -- D	December 2023	(2)	345	345
Pollution control bond -- bond insurance reimbursement agreements	2005 A -- G	2016 -- 2026	(2)	454	454
				\$ 1,619	\$ 1,619

(1) Off-balance sheet commitments

(2) Principal and debt service insured by the bond insurance company

PG&E Corporation

Convertible Subordinated Notes

PG&E Corporation currently has outstanding \$280 million of 9.50% Convertible Subordinated Notes that are scheduled to mature on June 30, 2010. These Convertible Subordinated Notes may be converted (at the option of the holder) at any time prior to maturity into 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 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" at the same payout as common stockholders with the number of shares determined by dividing the principal amount of the Convertible Subordinated Notes by the conversion price. On each of April 15 and July 15, 2005, PG&E Corporation paid approximately \$6 million of "pass-through dividends" to holders of the 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 "pass-through dividends," if any).

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 marked-to-market on PG&E Corporation's Consolidated Statements of Income as a non-operating expense (in Other expense, net), and reflected at fair value on PG&E Corporation's Consolidated Balance Sheets at June 30, 2005. At June 30, 2005, the total estimated fair value of the dividend participation rights component, on a pre-tax basis, was approximately \$91 million, of which \$20 million is classified as a current liability (in Current liabilities-Other) and \$71 million is classified as a noncurrent liability (in Noncurrent liabilities-Other). The change in the liability for the quarter ended June 30, 2005, was immaterial. The mark-to-market change was approximately \$33 million, pre-tax, for the quarter ended June 30, 2004.

Utility

First Mortgage Bonds/Senior Notes

On March 23, 2004, the Utility closed a public offering of \$6.7 billion of first mortgage bonds, or First Mortgage Bonds. The First Mortgage Bonds were offered in multiple tranches consisting of 3.60% First Mortgage Bonds due March 1, 2009 in the principal amount of \$600 million, 4.20% First Mortgage Bonds due March 1, 2011 in the principal amount of \$500 million, 4.80% First Mortgage Bonds due March 1, 2014 in the principal amount of \$1 billion, 6.05% First Mortgage Bonds due March 1, 2034 in the principal amount of \$3 billion, and Floating Rate First Mortgage Bonds due April 3, 2006 in the principal amount of \$1.6 billion. The Utility received proceeds of \$6.7 billion from the offering, net of a discount of \$18 million. The interest rate for the Floating Rate First Mortgage Bonds is based on the three-month London Interbank Offered Rate, or LIBOR, plus 0.70%, which resets quarterly. At June 30, 2005, the interest rate on the Floating Rate Senior Notes (as redesignated below) was 3.82%. First Mortgage Bonds in the aggregate amount of \$2.5 billion also were used to secure the Utility's obligations under various other debt agreements.

On October 3, 2004, the Utility partially redeemed Floating Rate First Mortgage Bonds due in 2006 in the aggregate principal amount of \$500 million. On January 3, 2005, in anticipation of the receipt of ERB proceeds, the Utility partially redeemed Floating Rate First Mortgage Bonds due in 2006 in the aggregate principal amount of \$300 million. On February 24, 2005, the Utility used a portion of the ERB proceeds to defease \$600 million of Floating Rate First Mortgage Bonds due in 2006. The defeased bonds were redeemed on April 3, 2005. On July 3, 2005, the remaining \$200 million of Floating Rate Senior Notes (as redesignated below) were redeemed.

The First Mortgage Bonds were secured by a first lien, subject to permitted exceptions, on substantially all of the Utility's real

property and certain tangible personal property related to the Utility's facilities. The lien was released on April 22, 2005, upon satisfaction of various conditions specified in the indenture, including confirmation from Moody's Investors Service, or Moody's, and Standard & Poor's Ratings Service, or S&P, that the Utility's unsecured debt ratings following the release would be at least Baa2 from Moody's and BBB from S&P. On March 3, 2005, Moody's upgraded the rating on the First Mortgage Bonds from Baa2 to Baa1. On April 22, 2005, the Utility and the trustee entered into an amended and restated indenture to eliminate the provisions related to the lien of the mortgage. The First Mortgage Bonds have been redesignated as follows:

First Mortgage Bonds	Redesignated As	Amount
3.6% First Mortgage Bonds due 2009	3.6% Senior Notes due 2009	\$600 million
4.2% First Mortgage Bonds due 2011	4.2% Senior Notes due 2011	\$500 million
4.8% First Mortgage Bonds due 2014	4.8% Senior Notes due 2014	\$1 billion
6.05% First Mortgage Bonds due 2034	6.05% Senior Notes due 2034	\$3 billion
Floating Rate First Mortgage Bonds due 2006	Floating Rate Senior Notes due 2006	\$200 million

Since the lien has been released there is no collateral securing the First Mortgage Bonds and the bonds, now designated as the Senior Notes as set forth in the table above, have become the Utility's unsecured general obligations ranking *pari passu* with the Utility's other senior unsecured debt. Under the indenture for the Senior Notes, the Utility has agreed that it will not incur secured debt (except for (1) debt secured by specified liens, and (2) secured debt in an amount not exceeding 10% of the Utility's net tangible assets, as defined in the indenture) unless the Utility provides that the Senior Notes will be equally and ratably secured with the new secured debt.

Pollution Control Bonds

On April 22, 2005, the Utility entered into an amendment to four reimbursement agreements totaling \$620 million related to letters of credit that had been issued to support certain pollution control bonds aggregating \$614 million issued on behalf of the Utility. In addition to reducing pricing and generally conforming the covenants and events of default to those in the \$1 billion working capital facility (described below), the term of the amended agreements has been extended to five years until April 22, 2010.

On May 24, 2005, the Utility entered into seven loan agreements with the California Infrastructure and Economic Development Bank to issue seven series of tax-exempt pollution control bonds, or PC Bonds Series A-G, totaling \$454 million. These series are in auction modes with initial interest rates ranging from 2.54% to 3.00%. Four series of the bonds have auctions every 35 days and three series have auctions every 7 days. Maturities on the bonds range from 2016 to 2026. At June 30, 2005, interest rates on these loans ranged from 1.94% to 3.00%. The bonds are insured by Ambac Assurance Corporation.

Repayment Schedule

At June 30, 2005, PG&E Corporation's and the Utility's combined aggregate amounts of scheduled repayments of long-term debt, rate reduction bonds, and ERBs as scheduled are reflected in the table below:

(in millions)	2005	2006	2007	2008	2009	Thereafter	Total
Long-term debt:							
PG&E Corporation							
Average fixed interest rate	-	-	-	-	-	9.50%	9.50%
Fixed rate obligations	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 280	\$ 280
Utility							
Average fixed interest rate	-	-	3.50%	-	3.60%	5.56%	5.22%
Fixed rate obligations	\$ -	\$ -	\$ 345	\$ -	\$ 600	\$ 4,683	\$ 5,628
Variable interest rate as of June 30, 2005	3.82%	-	-	-	-	2.33%	2.57%
Variable rate obligations	\$ 200	\$ -	\$ -	\$ -	\$ -	\$ 1,068	\$ 1,268
Other	2	1	-	-	-	-	3
Total consolidated long-term debt	\$ 202	\$ 1	\$ 345	\$ -	\$ 600	\$ 6,031	\$ 7,179

Energy Recovery Bonds & Rate Reduction Bonds:**Utility**

Average fixed interest rate	6.42%	6.44%	6.48%	-	-	-	6.45%
Rate reduction bonds	\$ 149	\$ 290	\$ 290	\$ -	\$ -	\$ -	\$ 729
Average fixed interest rate	3.32%	3.55%	3.87%	3.87%	4.05%	4.35%	4.03%
Energy recovery bonds	\$ 126	\$ 221	\$ 230	\$ 239	\$ 248	\$ 810	\$ 1,874

Credit Facilities and Short-Term Borrowings

The following table summarizes PG&E Corporation's and the Utility's short-term borrowings and outstanding credit facilities at June 30, 2005:

(in millions)

At June 30, 2005						
Authorized Borrower	Facility	Termination Date	Facility Limit	Letters of Credit Outstanding	Cash Borrowings	Availability
PG&E Corporation	Senior Credit Facility	December 2009	\$ 200 ⁽¹⁾	\$ -	\$ -	\$ 200
Utility	Accounts receivable financing	March 2007	650	-	-	650
Utility	Working capital facility	April 2010	1,000 ⁽²⁾	139	-	861
Total Credit Facilities			\$ 1,850	\$ 139	\$ -	\$ 1,711

⁽¹⁾ Includes \$50M sublimit for Letters of Credit and \$100M sublimit for swingline loans.

⁽²⁾ Includes a \$600M sublimit for Letters of Credit and \$100M sublimit for swingline loans.

PG&E Corporation**Senior Credit Facility**

On April 8, 2005, PG&E Corporation entered into an amendment, which became effective on April 12, 2005, to the \$200 million revolving senior unsecured credit facility, or the senior credit facility, to extend its term from three years to five years, with all amounts due and payable on December 10, 2009. In addition, the amendment made other changes to the senior credit facility to conform the covenants, representations and events of default to those in the Utility's working capital facility, discussed below. At June 30, 2005, PG&E Corporation had not made any borrowings or issued any letters of credit under the senior credit facility.

The fees and interest rates PG&E Corporation pays under the senior credit facility vary depending on the Utility's unsecured debt ratings issued by S&P and Moody's. A facility fee based on the total amount of the senior credit facility (regardless of the usage) and a utilization fee based on the average daily amount outstanding under the senior credit facility are payable quarterly in arrears. The utilization fee is payable during any quarter in which the average daily amount outstanding under the senior credit facility is in excess of 50% of the aggregate amount of the facility. At PG&E Corporation's option, any loan under the senior credit facility (other than swingline loans which are made available on a same day basis and repayable in full within thirty days) bears interest at a rate equal to the "applicable margin" plus one of the following indexes: (i) LIBOR or (ii) the base rate (the higher of (a) the administrative agent's base rate and (b) the Federal Funds rate plus 0.50%). Each swingline loan bears interest at the applicable margin plus the base rate. The applicable margin ranges between 0.50% and 1.35% for Eurodollar loans, and 0% and 0.5% for base rate loans. The facility fee ranges between 0.15% and 0.40%, and the utilization fee ranges between 0.125% and 0.25%. Interest is payable quarterly in arrears, or earlier for loans with shorter interest periods.

In addition, PG&E Corporation pays a fee for each letter of credit outstanding under the senior credit facility equal to the applicable margin for LIBOR loans to be shared by the lenders. PG&E Corporation also pays a fronting fee of 0.125% to the issuer of a letter of credit.

The senior credit facility includes usual and customary covenants for credit facilities of this type, including covenants limiting liens, mergers, sales of all or substantially all of PG&E Corporation's assets and other fundamental changes. Refer to the combined 2004 Annual Report for further details.

Utility

Working Capital Facility

On April 8, 2005, the Utility entered into a \$1 billion revolving credit facility, or the working capital facility. This credit facility replaced the \$850 million credit facility that the Utility entered into on March 5, 2004. The working capital facility includes a \$600 million sublimit for the issuance of letters of credit and a \$100 million sublimit for swingline loans. Loans under the working capital facility will be used primarily to cover operating expenses and seasonal fluctuations in cash flows and were used for bridge financing in connection with the reissuance of the tax-exempt pollution control bonds discussed below. Letters of credit under the working capital facility will be used primarily to provide credit enhancements to counterparties for natural gas and electricity procurement transactions.

Subject to obtaining any required regulatory approvals and commitments from existing or new lenders and satisfaction of other specified conditions, the Utility may increase, in one or more requests given not more frequently than once a year, the aggregate lenders' commitments under the working capital facility by up to \$500 million or, in the event that the Utility's \$650 million accounts receivable facility is terminated or expires, by up to \$850 million, in the aggregate for all such increases.

The working capital facility has a term of five years and all amounts will be due and payable on April 8, 2010. At the Utility's request and at the sole discretion of each lender, the facility may be extended for additional periods. The Utility has the right to replace any lender who does not agree to an extension.

The working capital facility includes usual and customary covenants for credit facilities of this type, including covenants limiting liens to those permitted under the Senior Notes indenture, mergers, sales of all or substantially all of the Utility's assets and other fundamental changes. In addition, the working capital facility also requires that the Utility maintain a debt to capitalization ratio of at most 65% as of the end of each fiscal quarter.

The fees and interest rates the Utility pays under the working capital facility vary depending on the Utility's unsecured debt rating by S&P and Moody's. A facility fee based on the total amount of the working capital facility (regardless of the usage) and a utilization fee based on the average daily amount outstanding under the working capital facility are payable quarterly in arrears. The utilization fee is payable during any quarter in which the average daily amount outstanding under the working capital facility is in excess of 50% of the aggregate amount of the facility. At the Utility's option, any loan under the working capital facility (other than swingline loans) bears interest at a rate equal to the "applicable margin" plus one of the following indexes: (i) LIBOR or (ii) the base rate (the higher of (a) the administrative agent's base rate and (b) the Federal Funds rate plus 0.50%). Each swingline loan bears interest at the applicable margin plus the base rate. The applicable margin is set at 0% for base rate loans and ranges between 0.22% and 0.675% for LIBOR loans. The facility fee ranges between 0.08% and 0.20%, and the utilization fee ranges between 0.10% and 0.25%. Interest is payable quarterly in arrears, or earlier for loans with shorter interest periods.

If the Utility's debt ratings from S&P and Moody's are at different levels, the higher rating applies. In addition, the Utility pays a fee for each letter of credit outstanding under the working capital facility equal to the applicable margin for LIBOR loans to be shared by the lenders. The Utility also pays a fronting fee of 0.125% to the issuer of a letter of credit.

At June 30, 2005, there were no loans outstanding under the \$1 billion working capital facility. At June 30, 2005, there were approximately \$139 million of letters of credit outstanding under the \$1 billion working capital facility.

On April 20, 2005, the Utility borrowed \$454 million under the working capital facility. The proceeds were used to repay \$454 million under certain reimbursement obligations the Utility entered into in April 2004 when its plan of reorganization under Chapter 11 became effective. These reimbursement obligations replaced the Utility's obligation to certain issuers of letters of credit that were drawn upon during the Chapter 11 proceeding in connection with the redemption of certain pollution control bonds that had been issued for the benefit of the Utility. The draw under the Utility's working capital facility was repaid with the proceeds of the tax-exempt PC Bonds Series A-G issued for the benefit of the Utility by the California Infrastructure and Economic Development Bank.

NOTE 4: ENERGY RECOVERY BONDS

In connection with the Settlement Agreement, PG&E Corporation and the Utility agreed to seek to refinance the unamortized portion of the Settlement Regulatory Asset and associated federal and state income and franchise taxes, in an aggregate principal amount of up to \$3.0 billion in two separate series up to one year apart, using a securitized financing supported by a dedicated rate component, or DRC. On February 10, 2005, PERF issued \$1.9 billion of ERBs. 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. Under the terms of a recovery property servicing agreement, DRC charges are collected by the Utility and remitted to PERF.

The aggregate principal amount of the first series of ERBs issued was approximately \$1.9 billion. They were issued in five classes, with scheduled maturities ranging from September 25, 2006 to December 25, 2012, and final legal maturities ranging from September 25, 2008 to December 25, 2014. Interest rates on the five classes range from 3.32% for the earliest maturing class to 4.47% for the latest maturing class. The proceeds of the first series of ERBs were paid by PERF to the Utility and were used by the Utility to refinance the remaining unamortized after-tax balance of the Settlement Regulatory Asset. The proceeds of the second series of ERBs, anticipated to be issued in November 2005 in

an aggregate amount of up to \$800 million (reflecting recent energy supplier settlements), will be paid by PERF to the Utility to pre-fund the Utility's tax liability that will be due as the Utility collects the DRC over the term of the first series of ERBs.

The total principal amount of ERBs outstanding was \$1.87 billion at June 30, 2005. The scheduled principal payments on the ERBs for the years 2005 through 2009 are \$126 million, \$221 million, \$230 million, \$239 million, and \$248 million, respectively. The remaining payments thereafter total \$810 million. 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 PG&E Corporation or the Utility 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 six months ended June 30, 2005 were as follows:

(in millions)	PG&E Corporation Total Common Shareholders' Equity	Utility Total Shareholders' Equity
Balance at December 31, 2004	\$ 8,633	\$ 9,130
Net income	485	499
Common stock issued	190	-
PG&E Corporation common stock repurchased:		
Settlement of accelerated share repurchase obligation - February 2005	(14)	-
Accelerated share repurchase - March 2005	(1,051)	-
Utility common stock repurchased		(960)
Common restricted stock amortization	7	-
Common stock dividends paid	(111)	(220)
Common stock dividends declared but not yet paid	(112)	-
Preferred stock dividends	-	(8)
Tax benefit from employee stock options	37	-
Minimum pension liability adjustment	(1)	(2)
Other	1	-
Balance at June 30, 2005	\$ 8,064	\$ 8,439

Stock Repurchases

On February 22, 2005, under an accelerated share repurchase arrangement entered into on December 15, 2004, PG&E Corporation paid Goldman Sachs & Co., or GS&Co., approximately \$14 million as a price adjustment based on the daily volume weighted average price, or VWAP, of PG&E Corporation common stock over the term of the arrangement. PG&E Corporation charged the payment to Common Stock within Common Shareholders' Equity.

On March 4, 2005, PG&E Corporation entered into an accelerated share repurchase arrangement with GS&Co. under which PG&E Corporation repurchased 29,489,400 shares of its common stock at an initial price of \$35.60 per share (for an aggregate amount including commissions of approximately \$1.05 billion). The repurchase was funded from available cash on hand and the repurchased shares were retired. PG&E Corporation charged approximately \$460 million to Common Stock and approximately \$591 million to Accumulated Earnings within Common Shareholders' Equity in respect of these transactions. Under the share forward component of the arrangement, or March 4, 2005 arrangement, certain payments were required by both PG&E Corporation and GS&Co. upon termination. Most significantly, PG&E Corporation was to receive from, or be required to pay to, GS&Co. a price adjustment on the repurchased shares based on the difference between the amount it paid and the VWAP over the approximately six month intended arrangement period. Upon an early termination of the March 4, 2005 arrangement, PG&E Corporation was required to compensate GS&Co. for its losses in connection with the arrangement unless the termination event resulted from the declaration of a dividend and a new share forward was executed to complete the March 4, 2005 arrangement. As discussed below, on June 15, 2005, the Board of Directors of PG&E Corporation declared a cash dividend on PG&E Corporation common stock for the second quarter of 2005.

Thus, on June 16, 2005, PG&E Corporation entered into a new share forward with GS&Co., or June 16, 2005 arrangement, based on 11,430,000 shares to complete the balance of the March 4, 2005 arrangement. The net of the amounts payable between the parties under the March 4, 2005 arrangement, including the amount of the price adjustment based on the VWAP, was approximately \$78,000 and was paid to GS&Co., at PG&E Corporation's option in cash, on June 30, 2005.

The June 16, 2005 arrangement is substantially identical to the March 4, 2005 arrangement, requiring certain payments by both PG&E

Corporation and GS&Co. As with the March 4, 2005 arrangement, the most significant of these payments is the price adjustment with respect to the 11,430,000 shares based on the difference between the \$35.60 purchase price per share and the VWAP over a period expected to extend to early September 2005. The price adjustment and any additional payments that PG&E Corporation may make under the June 16, 2005 arrangement can be settled, at PG&E Corporation's option, in cash or in shares of its common stock, or a combination of the two. Therefore, PG&E Corporation accounts for its payment obligations as equity.

Until the June 16, 2005 arrangement is completed or terminated, GAAP requires PG&E Corporation to assume that it will issue shares to settle its obligations (up to a maximum of 22,860,000 shares). PG&E Corporation must calculate the number of shares that would be required to satisfy its obligations upon completion of the June 16, 2005 arrangement based on the market price of PG&E Corporation's common stock at the end of a reporting period. The number of shares that would be required to satisfy the obligations must be treated as outstanding for purposes of calculating diluted earnings per share. Based on the market price of PG&E Corporation stock at June 30, 2005, PG&E Corporation would have an obligation to GS&Co. of approximately \$25.3 million upon completion of the June 16 arrangement. Accordingly, approximately 674,000 additional shares of PG&E Corporation common stock attributable to the accelerated repurchase arrangement were treated as outstanding for purposes of calculating diluted earnings per share.

On March 8, 2005, the Utility used proceeds from the issuance of ERBs (discussed in Note 4) to repay debt and to repurchase 22,023,283 shares of its common stock from PG&E Corporation for an aggregate purchase price of approximately \$960 million. The Utility had repurchased \$960 million of its common stock as of June 30, 2005. The Utility recognized charges of approximately \$141 million to Additional Paid-in Capital, approximately \$110 million to Common Stock, and approximately \$709 million to Reinvested Earnings within Shareholders' Equity in respect of this transaction.

Dividends

On June 15, 2005, the Board of Directors of the Utility declared a dividend of approximately \$118 million that was paid on June 16, 2005 to PG&E Corporation and PG&E Holdings LLC, a wholly owned subsidiary of the Utility that holds approximately 7% of the Utility's common stock.

Also, on June 15, 2005 the Board of Directors of PG&E Corporation declared a quarterly common stock dividend of \$0.30 per share to shareholders of record on June 30, 2005. On July 15, 2005 PG&E Corporation paid this dividend totaling approximately \$119 million, of which approximately \$7 million was paid to Elm Power Corporation, a wholly owned subsidiary of PG&E Corporation. In addition, PG&E Corporation paid approximately \$6 million in dividend equivalent payments to Convertible Subordinated Note holders of record on June 30, 2005.

PG&E Corporation charged dividends declared to Accumulated Earnings and the Utility charged dividends declared to Reinvested Earnings.

Redemption of Preferred Stock with Mandatory Redemption Provisions

On April 20, 2005, the Utility's Board of Directors authorized the redemption of all of the outstanding shares of the Utility's 6.57% Redeemable First Preferred Stock and 6.30% Redeemable First Preferred Stock totaling \$120 million aggregate par value. Both issues were redeemed on May 31, 2005. In addition to the \$25 per share redemption price, holders of the 6.57% Redeemable First Preferred Stock and the 6.30% Redeemable First Preferred Stock received an amount equal to all accumulated and unpaid dividends through May 31, 2005 on such shares totaling approximately \$644,000.

NOTE 6: RISK MANAGEMENT ACTIVITIES

Non-Trading Activities

The Utility enters into non-trading activities related to procurement of electricity and contracts associated with the natural gas and nuclear fuel portfolio. On the Utility's Consolidated Balance Sheets, price risk management activities are presented at fair value of \$24 million in other current assets and \$8 million in other current liabilities for June 30, 2005, and \$5 million in other current assets and \$11 million in other current liabilities for December 31, 2004. The costs of these derivatives are recovered in regulated rates charged to customers and the Utility records the offset to the regulatory accounts.

Credit Risk

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.

PG&E Corporation had gross accounts receivable of approximately \$2.1 billion at June 30, 2005 and \$2.2 billion at December 31, 2004. The majority of the accounts receivable are associated with the Utility's residential and small commercial customers. Based upon historical experience and evaluation of then-current factors, allowances for doubtful accounts of approximately \$91 million at June 30, 2005 and \$93 million at December 31, 2004 were recorded against those accounts receivable. In accordance with tariffs, credit risk exposure is limited by requiring deposits from new customers and from those customers whose past payment practices are below standard. The Utility has

a regional concentration of credit risk associated with its receivables from residential and small commercial customers in northern and central California. However, material loss due to non-performance from these customers is not considered likely.

The Utility manages credit risk for its largest 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.

Credit exposure for the Utility's largest customers and counterparties is calculated daily. If exposure exceeds the established limits, the Utility takes immediate action to reduce the exposure or obtain additional collateral, or both. 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 contractually specified limits.

The Utility calculates gross credit exposure for each of its wholesale customers and counterparties as the current mark-to-market value of the contract (*i.e.* , the amount that would be lost if the counterparty defaulted today) plus or minus any outstanding net receivables or payables, before the application of credit collateral. During 2004, the Utility recognized no material losses due to contract defaults or bankruptcies. At June 30, 2005, there were two counterparties that represented greater than 10% of the Utility's net credit exposure. Both of these counterparties were investment grade representing a total of approximately 44% of the Utility's net wholesale credit exposure.

The Utility conducts business with wholesale counterparties mainly in the energy industry, including other California investor-owned electric utilities, municipal utilities, energy trading companies, financial institutions, and oil and natural gas production companies located in the United States and Canada. 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. Credit losses experienced as a result of electrical and gas procurement activities are expected to be recoverable from customers and are therefore, not expected to have a material impact on earnings.

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 June 30, 2005 and December 31, 2004:

(in millions)	Gross Credit Exposure Before Credit Collateral ⁽¹⁾	Credit Collateral	Net Credit Exposure ⁽²⁾	Number of Wholesale Customer or Counterparties >10%	Net Exposure to Wholesale Customer or Counterparties >10%
June 30, 2005	\$ 165	\$ 11	\$ 154	2	\$ 68
December 31, 2004	105	7	98	3	62

- (1) Gross credit exposure equals mark-to-market value, 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, liquidity or credit reserves. The Utility's gross credit exposure includes wholesale activity only. Retail activity and payables are not included. Retail activity at the Utility consists of the accounts receivable from the sale of natural gas and electricity to residential and small commercial customers.
- (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.

The schedule below summarizes the credit quality of the Utility's net credit risk exposure to the Utility's wholesale customers and counterparties at June 30, 2005 and December 31, 2004:

(in millions)	Net Credit Exposure ⁽²⁾	Percentage of Net Credit Exposure
Credit Quality ⁽¹⁾		
June 30, 2005		
Investment grade ⁽³⁾	\$ 145	94%
Non-investment grade	9	6%
Total	\$ 154	100%
December 31, 2004		
Investment grade ⁽³⁾	\$ 79	81%
Non-investment grade	19	19%
Total	\$ 98	100%

- (1) Credit ratings are determined by using publicly available information. If provided a guarantee by a higher rated entity (e.g., an affiliate), the rating is determined based on the rating of the guarantor.

- (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.
- (3) Investment grade is determined using publicly available information, i.e., rated at least Baa3 by Moody's and BBB- by S&P. The Utility has assessed certain governmental authorities that are not rated through publicly available information as investment grade based upon an internal assessment of credit worthiness.

NOTE 7: 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

For the six months ended June 30, 2005, PG&E Corporation did not have any material new commitments or changes to its material commitments, other than those related to the Utility discussed below. The Canadian natural gas pipeline firm transportation contracts effective November 1, 2007 through October 31, 2023, are anticipated to be reassigned to the Utility during the third quarter of 2005. See PG&E Corporation's and the Utility's combined 2004 Annual Report for further discussion.

Utility

Power Purchase Agreements

As part of the ordinary course of business, the Utility enters into various agreements to purchase energy and makes payments on existing power purchase agreements. At June 30, 2005, the undiscounted future expected power purchase agreement payments were as follows:

(in millions)	
2005	\$ 1,805
2006	2,006
2007	2,140
2008	1,986
2009	1,779
Thereafter	12,761
Total	\$ 22,477

Payments made by the Utility under power purchase agreements amounted to approximately \$905 million for the six months ended June 30, 2005, and \$1,084 million for the same period in 2004.

Natural Gas Supply and Transportation Commitments

The Utility purchases natural gas directly from producers and marketers in both Canada and the United States to serve its core customers. The contract lengths and natural gas sources of the Utility's portfolio of natural gas procurement contracts have fluctuated, generally based on market conditions.

At June 30, 2005, the Utility's obligations for natural gas purchases and gas transportation services were as follows:

(in millions)	
2005	\$ 717
2006	417
2007	25
2008	13
2009	9
Thereafter	4
Total	\$ 1,185

Payments made by the Utility for natural gas purchases and gas transportation services amounted to approximately \$1,108 million for the six months ended June 30, 2005, and \$972 million for the same period in 2004.

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, known as RMR units, to remain available to generate electricity upon the ISO's demand when needed for local transmission system reliability. At June 30, 2005, as a party to a Transmission Control Agreement, or TCA, the Utility estimated that it could be obligated to pay the ISO approximately \$138 million for costs incurred under these RMR agreements during the period July 1, 2005 to June 30, 2006. Of this amount, the Utility estimates it would receive approximately \$15 million under these RMR agreements during the same period. These payments and receipts are subject to applicable ratemaking mechanisms.

In June 2000, a FERC administrative law judge, or ALJ, issued an initial decision in a rate case involving subsidiaries of Mirant Corporation. The ALJ approved rates and a ratemaking methodology that, if affirmed by the FERC, would have required the Mirant Corporation subsidiaries that are parties to three RMR agreements with the ISO to refund to the ISO, and the ISO to refund to the Utility, excess payments of approximately \$363 million, including interest, for the availability of RMR plants under these agreements. On July 14, 2003, Mirant Corporation and certain of its subsidiaries filed a petition for reorganization under Chapter 11 and, on December 15, 2003, the Utility filed claims in the Chapter 11 proceeding including a claim for an RMR refund. On January 14, 2005, the Utility entered into a settlement with Mirant Corporation and its subsidiaries that own RMR units that, among other matters, will resolve the Utility's claim through September 30, 2004 (see "Mirant Settlement" below). On April 13, 2005, the FERC approved the settlement agreement and also terminated the RMR rate case involving the Mirant Corporation subsidiaries without ruling on the ALJ's ratemaking methodology.

If the FERC adopted the ALJ's ratemaking methodology, the Utility believes it would be entitled to a refund of RMR payments made to other RMR plant owners. Therefore, on May 13, 2005, the Utility and other interested California parties, as well as the Mirant Corporation subsidiaries, sought rehearing of the part of the FERC's April 13 order terminating the RMR case and urged the FERC to issue a final decision approving the ratemaking methodology adopted in the ALJ's initial decision. On June 3, 2005, the FERC issued an order denying rehearing. In a separate order issued on June 3, the FERC also dismissed a complaint that had been filed in November 2001 at the FERC against other RMR owners alleging that the ratemaking methodology approved by the ALJ should apply to other RMR agreements.

On July 5, 2005, the Utility, along with other interested California parties, filed a request for rehearing of the FERC's June 3 order dismissing the complaint and urged the FERC to find other owners' RMR rates unlawfully high based on the ratemaking methodology approved by the ALJ in the Mirant RMR rate case. Any refunds the Utility may obtain will be credited to the Utility's retail electricity customers. PG&E Corporation and the Utility are unable to predict the outcome of this matter.

Other Commitments and Operating Leases

The Utility has other commitments relating to operating leases, capital infusion agreements, equipment replacements, the self-generation incentive program exchange agreements, telecommunication contracts and the electric generating interconnection project contracts. At June 30, 2005, the future minimum payments related to other commitments were as follows:

(in millions)	
2005	\$ 92
2006	114
2007	18
2008	14
2009	6
Thereafter	14
Total	\$ 258

Payments made by the Utility for other commitments amounted to approximately \$48 million for the six months ended June 30, 2005, and \$63 million for the same period in 2004.

Contingencies

PG&E Corporation

PG&E Corporation retains a guarantee related to certain NEGT indemnity obligations issued to the purchaser of an NEGT subsidiary company during 2000, up to \$150 million. The underlying indemnity obligations of NEGT have expired and PG&E Corporation's sole remaining exposure relates to the potential of 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 any claims will occur under the guarantee. Accordingly, PG&E Corporation has made no provision for this guarantee at June 30, 2005.

PG&E Corporation also retains a guarantee of the Utility's underlying obligation to pay workers' compensation claims. As of June 30, 2005, the actuarially determined workers' compensation liability was approximately \$227.2 million.

Utility

PX Block-Forward Contracts

The Utility had PX block-forward contracts, which were seized by California's then-Governor Gray Davis in February 2001 for the benefit of the state, acting under California's Emergency Services Act. At the time the state of California seized them, the block-forward contracts had an estimated unrealized gain of up to \$243 million which amount was reflected in account receivables in the Utility balance sheet. The Utility, the PX, and some of the PX market participants have filed claims in state court against the state of California to recover the value of the seized contracts. The state of California disputes the plaintiffs' rights to recover any valuations. The Utility has accrued a reserve for the estimated value of the seized contracts. This state court litigation is pending.

California Energy Crisis Proceedings

FERC Proceedings

Various entities, including the Utility and the state of California are seeking up to \$8.9 billion in refunds for electricity overcharges on behalf of California electricity purchasers for the period May 2000 to June 2001 through a proceeding pending at the FERC and in the appellate courts reviewing FERC decisions. This proceeding, the Refund Proceeding, commenced on August 2, 2000 when a complaint was filed against all suppliers in the ISO and PX markets. On July 25, 2001, the FERC held that refunds would be available for certain overcharges, and established a process to determine the refunds but asserted that it could not order market-wide refunds for periods before October 2, 2000. In December 2002, a FERC ALJ issued an initial decision in the Refund Proceeding finding that power suppliers overcharged the utilities, the state of California and other buyers approximately \$1.8 billion from October 2, 2000 to June 20, 2001, but that California buyers still owe the power suppliers approximately \$3.0 billion, leaving approximately \$1.2 billion in net unpaid bills.

In March 2003, the FERC confirmed most of the ALJ's findings in the Refund Proceeding, but partially modified the refund methodology to include use of a new natural gas price methodology as the basis for mitigated prices. The FERC indicated that it would consider later allowances claimed by sellers for natural gas costs above the natural gas prices in the refund methodology. In March 2005, FERC extended the time for review of gas allowance claims and the ISO expects to receive the required audited fuel cost information by November 2005. The FERC directed the ISO and the PX (which operates solely to reconcile remaining refund amounts owed) to make compliance filings establishing refund amounts. The ISO has recently indicated that it plans to make its compliance filing in the first quarter of 2006, with the PX to follow. In October 2003, the FERC affirmed its March 2003 decision and various parties appealed to the Ninth Circuit. Briefs have been submitted concerning which power suppliers are subject to refunds, the appropriate time period for which refunds can be ordered, and which transactions are subject to refunds. These matters were argued before the Ninth Circuit on April 12 and 13, 2005, and a decision is expected by the end of 2005.

The final refunds will not be determined until the FERC issues a final decision in the Refund Proceeding, following the ISO and PX compliance filings and the resolution of the appeals of the FERC's orders. In addition, future refunds could increase or decrease as a result of retroactive adjustments proposed by the ISO, which incorporate revised data provided by the Utility and other entities.

In the FERC's separate proceedings to investigate whether tariff violations occurred in the period before October 2, 2000, the FERC has asserted that it has the power to order power suppliers to disgorge any profits if the FERC finds that the tariffs in force at that time were violated or subject to manipulation. In September 2004, the Ninth Circuit found that the FERC has the authority to provide refunds for tariff violations involving inadequate transaction reporting for sales into the California spot markets throughout the period before October 2, 2000. The FERC has not yet acted on this finding and it is uncertain how it will be applied by the FERC.

The Utility recorded approximately \$1.8 billion of claims filed by various electricity generators in its Chapter 11 proceeding as disputed claims. This amount is subject to a pre-petition offset of approximately \$200 million, reducing the net liability recorded to approximately \$1.6 billion. Under a bankruptcy court order, the aggregate allowable amount of unpaid PX and generator claims was limited to approximately \$1.6 billion. The Utility currently estimates that the claims would have been reduced to approximately \$1.0 billion based on the refund methodology recommended in the FERC ALJ's initial decision. The revised methodology adopted by the FERC's March 2003 decision could further reduce the amount by several hundred million dollars, offset by the amount of any additional fuel cost allowance for suppliers.

The Utility has entered into settlements with various power suppliers resolving certain disputed claims and the Utility's refund claims against these power suppliers. As of June 30, 2005, the Utility has recorded total offsets to the Settlement Regulatory Asset and credits to customers of approximately \$765 million in connection with these settlements. (The settlement agreements make provision for several contingencies that may affect the final amounts actually received by the Utility). Approximately \$310 million of these credits were recorded as an offset to the Settlement Regulatory Asset that was refinanced through the issuance of the first series of ERBs in February 2005. The remaining \$455 million has been credited to the ERBBA, offset by net interest costs of approximately \$70 million related to net disputed claims. Amounts received by the Utility under future settlements with energy suppliers will be credited to customers, except for those related to certain wholesale power purchases, either as a reduction to the amount of the second series of ERBs, anticipated to be issued in November 2005, or if refunds are received after the second series of ERBs is issued, as a credit to the ERBBA.

Enron Settlement

On July 15, 2005, the Utility along with the Attorney Generals of the States of California, Oregon and Washington, the California Department of Water Resources, or DWR, the FERC's Office of Oversight and Investigations, Southern California Edison, and San Diego Gas & Electric Company, entered into a memorandum of understanding, or MOU, with Enron Corporation and various of its subsidiaries, or Enron, to satisfy Enron's liabilities in the Refund Proceeding. The MOU is subject to negotiation and execution of a definitive agreement to be filed with the FERC by August 19, 2005. The definitive agreement will not become effective until approved by the FERC, the CPUC and the

bankruptcy court where Enron's bankruptcy cases are pending. The MOU provides that Enron would pay \$47 million in cash to the California parties and allow an unsecured claim of \$875 million in the bankruptcy proceeding of Enron Power Marketing, Inc., a subsidiary through which Enron conducted its power marketing operations in California. The actual value of the bankruptcy claim is uncertain and the final amount would not be realized until the conclusion of the bankruptcy case. Further, the allocation of the amount of the cash payment and the amount realized upon payment of the allowed claim among the California utilities remains subject to negotiation and agreement.

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 first part of the two-part settlement is between Mirant and several California parties, including the California Attorney General's Office, the DWR, the CPUC, Southern California Edison, San Diego Gas & Electric Company, and the Utility, or the California Parties, resolving market manipulation claims, including Mirant's liability for FERC refunds, penalties and civil liabilities arising out of the California energy crisis in 2000 to 2001. Under this portion of the agreement, Mirant will provide the California Parties 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 will receive approximately \$130 million in cash equivalents and a reduction in the Utility's payable to the PX and \$40 million in allowed claims. Most of the \$130 million consideration has been included in the \$455 million credited to customers through the ERBBA during the quarter as described above. The final cash value of the allowed claims will not be known until the completion of Mirant's bankruptcy proceedings.

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. Under the settlement agreement, Mirant has agreed to transfer to the Utility the equipment, permits and contracts for the construction of Contra Costa Unit 8, a modern 530-megawatt electric generating facility Mirant started to build, but never completed. On June 10, 2005, the Utility and Mirant completed negotiations on an Asset Transfer Agreement, which provides the terms and conditions under which the Contra Costa 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 \$310 million construction of the facility, and funding to operate it for up to three years. The Utility requested hearings in October 2005 and a final decision in January 2006. If the Utility and Mirant do not receive the necessary approvals, including CPUC authorization, the Utility will be paid \$70 million in lieu of transferring the assets. The settlement agreement also includes a contract that would give the Utility the right from 2006 through 2012 to dispatch power from certain RMR units owned by Mirant subsidiaries, subject to continued RMR status, when the facilities are not needed by the ISO to meet local reliability needs. In addition, the Utility will receive approximately \$60 million of allowed claims, credits, offsets, and/or cash from Mirant and Mirant will withdraw its outstanding claim in the Utility's bankruptcy proceeding of approximately \$20 million. The settlement may also include separate options under which the Utility, under certain circumstances, would have the right to acquire Mirant's existing Contra Costa and Pittsburg power plants.

The settlement agreement became effective on April 15, 2005, after all regulatory and other approvals required by the settlement agreement were obtained. In June 2005, the Utility recorded a receivable and a corresponding regulatory liability of approximately \$140 million, which includes the \$70 million discussed above, representing the expected value to be received in connection with the Mirant settlement agreement.

Nuclear Insurance

The Utility has several types of nuclear insurance for the Diablo Canyon Power Plant, or Diablo Canyon, and 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. 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 \$42.5 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. Under the Terrorism Risk Insurance Act of 2002, there is no policy coverage limitations for an act caused by foreign terrorists because NEIL would be entitled to receive substantial reimbursement by the federal government. The Terrorism Risk Insurance Act of 2002 expires on December 31, 2005.

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, designed for the production of electrical energy, and have a rated capacity of 100 megawatts, or 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 \$10 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

\$20 million per incident. Although the Price-Anderson Act expired on December 31, 2003, coverage continues to be provided to all licensees, including Diablo Canyon, which had coverage before December 31, 2003. Congress may address renewal of the Price-Anderson Act in future energy legislation.

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 NRC, 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 allocated contracts provided approximately 26% of the electricity delivered to the Utility's customers for the six-month period ended June 30, 2005. The DWR purchased the electricity under contracts with various generators. The Utility 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, which is the portion of the demand of a utility's customers, plus applicable reserve margins, not satisfied from that 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 agent for the collection of the DWR's revenue requirements from the Utility's customers.

The current DWR contracts terminate at various times through 2012, 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 that electricity is dispatched and delivered. In the Utility's proposed long-term integrated energy resource plan filed with the CPUC in July 2004 and approved in December 2004, the Utility has not assumed that the DWR contracts will be renewed beyond their current expiration dates.

The DWR has stated publicly 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 will be no less than A2 and the Utility's long-term issuer credit rating by S&P 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.

Defined Benefit Pension Plan Additional Minimum Liability

If current market conditions continue through the remainder of 2005, the Utility anticipates that its defined benefit retirement plan assets at December 31, 2005 will be less than the accumulated benefit obligations due to changes in certain market yields used to estimate benefit obligations and low stock market returns. The ultimate amount, if any, that the Utility would be required to recognize as an additional minimum pension liability is dependent upon certain market yields at December 31, 2005 and investment returns through the remainder of 2005 and as such, cannot be estimated at this time.

The Utility has recently filed a petition requesting the CPUC to authorize it to resume contributions to its employee pension trust beginning in 2006 based upon the funded status of the pension plan. The Utility is unable to predict the outcome of the petition to the CPUC, the amount of minimum pension liability to be recognized, if any, or the impact on its financial condition or results of operations.

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, or CERCLA, 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 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 \$410 million at June 30, 2005, and approximately \$327 million at December 31, 2004. During the six months ended June 30, 2005, the liability increased by approximately \$83 million mainly due to reassessment of the estimated cost of remediation and remediation payments. The approximately \$410 million accrued at June 30, 2005, includes approximately \$101 million related to the pre-closing remediation liability associated with divested generation facilities and approximately \$309 million related to remediation costs for those generation facilities that the Utility still owns, gas gathering sites, compressor stations, 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 approximately \$410 million environmental remediation liability, approximately \$143 million has been included in prior rate setting proceedings and the Utility expects that approximately \$202 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 \$578 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 \$578 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 \$81 million (including interest). PG&E Corporation has filed protests contesting certain adjustments made by the IRS in that audit and currently is discussing these adjustments with the IRS' Appeals Office.

The IRS also has completed its audit of PG&E Corporation's 1999 and 2000 consolidated federal income tax returns and refunded \$14 million to PG&E Corporation. As a result of the resolution of this audit, PG&E Corporation paid the Utility \$18 million relating to the Utility matters that had been included in the audit, the Utility reduced its reserve for outstanding tax audits by \$11 million and PG&E Corporation recognized tax benefits of \$32 million for NEGT related matters included in the audit.

The IRS is auditing PG&E Corporation's 2001 and 2002 consolidated federal income tax returns. The IRS has indicated that it plans to complete the audit and issue a Revenue Agent Report in the third or fourth quarter of 2005. During its examination, the IRS has proposed to disallow synthetic fuel credits claimed by PG&E Corporation. The IRS also has proposed to disallow a number of deductions, the largest of which is a deduction for abandoned or worthless assets owned by NEGT. PG&E Corporation believes that it properly reported these transactions in its tax returns and will contest any IRS assessment. If the IRS includes all of its proposed disallowances in the final Revenue Agent Report, the alleged tax deficiency would approximate \$452 million. Of this deficiency, approximately \$104 million relates to the synthetic fuel credits and approximately \$316 million is of a timing nature which would be refunded to PG&E Corporation in the future. In the second quarter of 2005, PG&E Corporation has increased its reserve with respect to NEGT tax issues included in the 2001 and 2002 consolidated federal income tax returns by \$32 million to a total of \$84 million for all open tax audits.

PG&E Corporation has filed its 2003 federal income tax return and expects to file its 2004 return by September 15, 2005. PG&E Corporation has paid estimated federal income taxes with respect to the 2004 tax year, which amount includes the estimated 2004 tax liability of \$94 million related to NEGT through October 29, 2004, the effective date of NEGT's plan of reorganization. PG&E Corporation has previously recognized this estimated tax liability in discontinued operations. PG&E Corporation expects the IRS to begin its audit of PG&E Corporation's 2003 and 2004 tax returns by the end of the year.

During second quarter of 2005, NEGT-related activities had no impact on discontinued operations and consisted of the net loss benefit related to the 1999-2000 audit, offset by the provision for additional tax assessments for the 2001-2002 audit.

As of June 30, 2005, PG&E Corporation has accrued approximately \$133 million to cover potential tax obligations and interest related to outstanding audits, including the \$84 million related to NEGT issues discussed above, and \$49 million to cover potential tax obligations related to non-NEGT issues. The increase in PG&E Corporation's accrual at June 30, 2005, compared to December 31, 2004, of approximately \$40 million is primarily related to the current quarter increase of \$32 million in the accrual for NEGT tax issues included in the 2001-2002 audit discussed above. In addition, as of June 30, 2005, the Utility has accrued approximately \$52 million to cover potential tax obligations discussed above, including interest, related to outstanding audits. This represents an \$11 million reduction from the accrual at December 31, 2004, and reflects the resolution in the current quarter of the 1999-2000 audit discussed above. Considering these reserves, PG&E Corporation does not expect the resolution of the outstanding audits to have a material impact on its financial condition or results of operations.

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 noncurrent liabilities in the Consolidated Balance Sheets, and totaled approximately \$209 million at June 30, 2005 and \$220 million at December 31, 2004. As to the chromium litigation described below, PG&E Corporation and the Utility are unable to predict whether the ultimate 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.

PG&E Corporation and the Utility do not believe it is probable that losses associated with legal matters other than the chromium litigation, 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

There are 14 civil suits pending against the Utility in several California state courts in which plaintiffs allege that exposure to chromium at or near the Utility's compressor stations at Hinkley and Kettleman, California, and the area of California near Topock, Arizona, caused personal injuries, wrongful deaths, or other injury and seek related damages. One of these suits also names PG&E Corporation as a defendant. Currently, there are approximately 1,200 plaintiffs in the chromium litigation cases. Approximately 1,260 individuals filed proofs of claims in the Utility's Chapter 11 case, most of whom also are plaintiffs in the chromium litigation cases. Approximately 1,035 of these claimants filed claims requesting an approximate aggregate amount of \$580 million and another approximately 225 claimants filed claims for an "unknown amount." Pursuant to the Utility's plan of reorganization, these claims have passed through the Utility's Chapter 11 proceeding unimpaired.

The Utility is responding to the suits in which it has been served and is asserting affirmative defenses. The Utility will pursue appropriate legal defenses, including statute of limitations, exclusivity of workers' compensation laws, and factual defenses, including lack of exposure to chromium and the inability of chromium to cause certain of the illnesses alleged.

To assist in managing and resolving litigation with this many plaintiffs, the parties agreed to select plaintiffs from three of the cases for a test trial. Plaintiffs' counsel selected ten of these initial trial plaintiffs, defense counsel selected seven of the initial trial plaintiffs, and one plaintiff and two alternates were selected at random.

The Utility has filed 14 motions in the Superior Court for the County of Los Angeles, or Superior Court, challenging the test trial plaintiffs' lack of admissible scientific evidence that chromium caused the alleged injuries. In February 2005, the Superior Court denied two of these motions. The Utility filed motions for reconsideration of these orders with the Superior Court and also filed a request with the appellate court seeking to overturn or modify the orders because they are inconsistent with recent California appellate decisions concerning the admissibility of expert testimony and the requirements for proving medical causation. After these motions for reconsideration and the request were filed, the California Supreme Court granted review of one of these recent appellate decisions. In April 2005, the Superior Court heard arguments on both motions for reconsideration and denied the motions in July 2005.

On June 9, 2005, the Superior Court denied another of the Utility's motions to exclude evidence, and the Utility filed a motion for reconsideration. On July 18, 2005, the Superior Court denied this motion for reconsideration. The Superior Court denied another of the Utility's motions to exclude evidence on June 29, 2005.

As previously disclosed, the Utility has recorded a \$160 million reserve in its financial statements with respect to the chromium litigation. Given recent rulings and appellate writs regarding the Utility's motions, and the California Supreme Court's current review of similar issues in unrelated litigation, PG&E Corporation and the Utility are no longer able to predict whether the ultimate outcome of this matter, after taking into account the amount already reserved at June 30, 2005, would have a material adverse impact on PG&E Corporation's or the Utility's 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 an energy-based holding company that 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, electricity 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. The Utility, incorporated in California in 1905, is the predecessor of PG&E Corporation. 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 for which it is subject to a majority of the risk of loss or entitled to receive a majority of the entity's residual returns. 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 included in their combined 2004 Annual Report on Form 10-K, or 2004 Annual Report, filed with the Securities and Exchange Commission, or SEC.

The Utility served approximately 5.0 million electricity distribution customers and approximately 4.1 million natural gas distribution customers at June 30, 2005. The Utility had approximately \$34.0 billion in assets at June 30, 2005 and generated revenues of approximately \$5.2 billion in the six months ended June 30, 2005.

The Utility is regulated primarily by the California Public Utilities Commission, or the CPUC, and the Federal Energy Regulatory Commission, or the 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 PG&E Corporation's and the Utility's combined 2004 Annual Report and below under "Regulatory Matters."

Factors Affecting Financial Condition and Results of Operations

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 issuance of approximately \$1.9 billion of Energy Recovery Bonds, or ERBs, on February 10, 2005 by PG&E Energy Recovery Funding LLC, or PERF, a limited liability company that is wholly owned and consolidated by the Utility (but legally separate from the Utility). The Utility used the ERB proceeds to repay debt and repurchase stock resulting in the elimination of the Settlement Regulatory Asset on which the Utility was entitled to earn an 11.22% rate of return on equity, or ROE, as provided in the settlement agreement entered into among the Utility, PG&E Corporation and the CPUC to resolve the Utility's Chapter 11 case, or the Settlement Agreement. The elimination of the ROE on the Settlement Regulatory Asset reduced the Utility's net income for the three and six-month periods ended June 30, 2005 by approximately \$28 million and \$46 million, compared to the same periods in 2004, when the Utility earned the 11.22% ROE on the Settlement Regulatory Asset. Total net income for 2005 is estimated to be reduced by approximately \$100 million, compared to 2004, due to the elimination of the 11.22% ROE on the Settlement Regulatory Asset. The Utility's net income also will be reduced by approximately \$55 million in 2006 representing the equity portion of the carrying cost credit associated with the second series of ERBs anticipated to be issued in November 2005 in an aggregate amount of up to \$800 million and the after-tax balance of energy supplier refunds received before the second series of ERBs is issued. See "Regulatory Matters" below.
- As a result of the increase in the Utility's equity ratio from 49% in 2004 to 52% in 2005, the Utility's equity earnings in the three and six-month periods ended June 30, 2005, increased by approximately \$7 million and \$21 million compared to the same periods in 2004. Based on the 52% equity ratio, it is expected that the Utility's equity earnings for the second half of

2005 will increase by approximately \$20 million compared to the same period in 2004. Net income for 2006 will be affected by the amount of ROE authorized by the CPUC for 2006. The Utility's currently authorized ROE of 11.22% will be in effect until the Utility's 2006 cost of capital application is approved by the CPUC. On May 9, 2005, the Utility filed its 2006 cost of capital application with the CPUC for its electric utility generation and distribution operations and gas distribution operations requesting an authorized ROE of 11.50% and that the equity component of its authorized capital structure for 2006 remain at 52.0%. The Utility has proposed that any changes to its electric and gas revenue requirements resulting from adjustments to its authorized 2006 test year cost of capital be effective January 1, 2006. (See "Regulatory Matters" below).

- With the achievement of a 52% equity ratio, during the six months ended June 30, 2005, the Utility used cash (including the ERB proceeds) in excess of amounts needed for operations, debt service and repayment, base capital expenditures, and the reinstated quarterly dividend, to repurchase common stock. In turn, PG&E Corporation used the cash received from the Utility to recommence the payment of a regular \$0.30 per share quarterly common stock dividend and to repurchase common stock from shareholders. PG&E Corporation's repurchase of common stock under accelerated share repurchase arrangements increased both basic and diluted earnings per share by approximately \$0.06 and \$0.05, respectively, for the six months ended June 30, 2005. The calculation of PG&E Corporation's earnings per share for future periods will be affected by the accelerated share repurchase arrangements that PG&E Corporation has entered into with Goldman Sachs & Co., or GS&Co. In addition, PG&E Corporation anticipates repurchasing additional shares subject to authorization by the Board of Directors. Any additional repurchases would be made toward the end of 2005 and would not significantly affect earnings per share in 2005. (See "Liquidity and Financial Resources" below).
- During the three months ended June 30, 2004, the Utility recorded additional revenues authorized in the CPUC's May 2004 decision in the Utility's 2003 General Rate Case, or GRC. Because the additional revenues covered 2003 and the six-month period ended June 30, 2004, the total GRC revenues for the three-month period ended June 30, 2005 are approximately \$100 million lower than in the same period in 2004. On August 1, 2005, the Utility notified the CPUC that it intended to file its 2007 GRC application to determine the amount of authorized base revenues to be collected from customers to recover the Utility's basic business and operational costs for its gas and electric distribution and electric generation operations for the period 2007 through 2009. The Utility indicated that the Utility's GRC application will request an increase in electric and gas distribution revenue requirements of \$393 million and \$61 million, respectively, over the projected authorized 2006 revenue requirements. The Utility has proposed a mechanism to share savings with customers that may be achieved through implementation of specific initiatives the Utility has identified to provide better, faster and more cost-effective service to its customers. (See "Regulatory Matters" below).
- The Utility's future financial condition and results of operations will be affected by the amount of future capital expenditures the Utility may make in long-term generation resource and infrastructure improvements. The Utility is evaluating initial bids that it has received from third parties to provide long-term generation resources (which may take the form of conventional or renewable resources to be provided under utility-owned projects or turnkey developments, or buyouts, or third party power purchase agreements) for approximately 1,200 megawatts, or MW, of peaking resources by 2008 and an additional 1,000 MW of load-following resources by 2010. The Utility anticipates that contracts for the winning bidders will be submitted to the CPUC for approval in the second half of 2005. (See "Regulatory Matters.") In addition, on June 17, 2005, the Utility filed an application with the CPUC to complete and operate, under a cost-of-service ratemaking structure, the Contra Costa Unit 8 facility, a proposed modern 530 MW power plant currently owned by Mirant Corporation. Also, on June 16, 2005, the Utility also requested the CPUC to approve an application for deployment of the Utility's full advanced metering infrastructure, or AMI, project at an estimated cost of \$1.46 billion, which includes an estimated capital cost of \$1.26 billion, based on a five year installation schedule for virtually all of the Utility's electric and gas customers starting in 2006. (See "Capital Expenditures" below).

In addition to the factors discussed above, PG&E Corporation's and the Utility's future financial condition and results of operations are subject to the uncertainties and risk factors discussed below, as well as to the risk factors discussed in their 2004 Annual Report.

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 time the statements were made. These forward-looking statements are identified by words such as "assume," "expect," "intend," "plan," "project," "believe," "estimate," "predict," "anticipate," "may," "might," "will," "should," "would," "could," "goal," "potential" and similar expressions. Although PG&E Corporation and the Utility are not able to predict all the factors that may affect future results, some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include:

Operating Environment

- Unanticipated changes in operating expenses or capital expenditures, which may affect the Utility's ability to earn its authorized rate of return;
- The level and volatility of wholesale electricity and natural gas prices and supplies, the Utility's ability to manage and respond to the levels and volatility successfully and the extent to which the Utility is able to timely recover increased costs related to such volatility;
- Weather, storms, earthquakes, fires, floods, other natural disasters, explosions, accidents, mechanical breakdowns and other events or hazards that affect demand, result in power outages, reduce generating output, or cause damage to the Utility's assets or operations or those of third parties on which the Utility relies, and the extent to which the Utility is able to timely recover costs related to such events;
- Unanticipated population growth or decline, changes in market demand and demographic patterns, and general economic and financial market conditions, including unanticipated changes in interest or inflation rates, and the extent to which the Utility is able to timely recover its costs in the face of such events;
- The operation of the Utility's Diablo Canyon nuclear power plant, or Diablo Canyon, which exposes the Utility to potentially significant environmental costs and capital expenditure outlays and, to the extent the Utility is unable to increase its spent fuel storage capacity by 2007 or find an alternative depository, the risk that the Utility may be required to close Diablo Canyon and purchase electricity from more expensive sources, and the extent to which the Utility is able to timely recover related costs and expenses;
- Actions of credit rating agencies;
- Significant changes in the Utility's relationship with its employees, the availability of qualified personnel and the potential adverse effects if labor disputes were to occur; and
- Acts of terrorism.

Legislative and Regulatory Environment

- The impact of current and future ratemaking actions of the CPUC, including the risk of material differences between forecasted costs used to determine rates and actual costs incurred;
- Prevailing governmental policies and legislative or regulatory actions generally, including those of the California legislature, the U.S. Congress, the CPUC, the FERC, and the Nuclear Regulatory Commission, or the NRC, with regard to the Utility's allowed rates of return, industry and rate structure, recovery of investments and costs, acquisitions and disposal of assets and facilities, treatment of affiliate contracts and relationships, and operation and construction of facilities;
- The extent to which the CPUC or the FERC delays or denies recovery of the Utility's costs, including electricity 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 balancing accounts;
- How the CPUC administers the capital structure, stand-alone dividend, and first priority conditions of the CPUC's decisions permitting the establishment of holding companies for the California investor-owned electric utilities;

- The terms and conditions under which the CPUC authorizes the Utility to issue debt and equity in the future, and the extent to which the terms and conditions limit the Utility's ability to issue debt in the future;
- Whether the Utility is determined to be in compliance with all applicable rules, tariffs and orders relating to electricity and natural gas utility operations, 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 to comply with existing and future environmental laws, regulations and policies.

Pending Regulatory Proceedings and Litigation

- Whether the assumptions and forecasts underlying the Utility's CPUC-approved long-term electricity procurement plan prove to be accurate, the terms and conditions of the generation or procurement commitments the Utility enters into in connection with its plan, the extent to which the Utility is able to recover the costs it incurs in connection with these commitments and the extent to which a failure to perform by any of the counterparties to the Utility's electricity purchase contracts or the California Department of Water Resources, or the DWR, contracts allocated to the Utility's customers affects the Utility's ability to meet its obligations or to recover its costs;
- The outcome of the regulatory proceedings pending at the CPUC and the FERC discussed in "Regulatory Matters" below, including the Utility's 2007 GRC and the Utility's request for a revenue requirement to fund pension contributions that may be required in the future;
- The timing and resolution of the pending appeals of the bankruptcy court order confirming the Utility's plan of reorganization under Chapter 11; and
- The outcome of the litigation pending against the Utility in California state court involving allegations of injury allegedly caused by exposure to chromium at certain of the Utility's gas compressor stations and other pending litigation.

Competition and Bypass

- Increased competition as a result of the takeover by condemnation of the Utility's distribution assets, duplication of the Utility's distribution assets or service by local public utilities, and other forms of competition that may result in stranded investment capital, decreased customer growth, loss of customer load and additional barriers to cost recovery; and
- The extent to which the Utility's distribution customers switch between purchasing electricity from the Utility and from alternate energy service providers as direct access customers, the extent to which cities, counties and others in the Utility's service territory begin directly serving the Utility's customers, and the extent to which the Utility's customers become self-generators, results in stranded generating asset costs and non-recoverable procurement costs.

See the section entitled "Risk Factors" in PG&E Corporation's and the Utility's combined 2004 Annual Report 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 Consolidated Statements of Income for the three and six-month periods ended June 30, 2005 and 2004.

(in millions)	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2005	2004	2005	2004
Utility				
Electric operating revenues	\$ 1,780	\$ 2,063	\$ 3,439	\$ 3,851

Natural gas operating revenues	718	686	1,727	1,617
Total operating revenues	2,498	2,749	5,166	5,468
Cost of electricity	487	685	884	1,254
Cost of natural gas	347	278	967	857
Operating and maintenance	670	748	1,441	1,557
Recognition of regulatory assets	-	-	-	(4,900)
Depreciation, amortization and decommissioning	454	352	839	650
Reorganization professional fees and expenses	-	4	-	6
Total operating (gain) expenses	1,958	2,067	4,131	(576)
Operating income	540	682	1,035	6,044
Interest income ⁽¹⁾	20	23	39	34
Interest expense	(124)	(158)	(278)	(372)
Other income, net ⁽²⁾	2	20	4	26
Income before income taxes	438	567	800	5,732
Income tax provision	166	159	309	2,258
Income available for common stock	\$ 272	\$ 408	\$ 491	\$ 3,474

PG&E Corporation, Eliminations and Other ⁽³⁾

Operating revenues	\$ -	\$ -	\$ -	\$ -
Operating (gain) expenses	-	10	(5)	20
Operating income (loss)	-	(10)	5	(20)
Interest income	(4)	2	(2)	5
Interest expense	(7)	(18)	(14)	(34)
Other expense, net ⁽²⁾	(4)	(34)	(7)	(67)
Income (loss) before income taxes	(15)	(60)	(18)	(116)
Income tax benefit	(10)	(24)	(12)	(47)
Net loss	\$ (5)	\$ (36)	\$ (6)	\$ (69)

Consolidated Total

Operating revenues	\$ 2,498	\$ 2,749	\$ 5,166	\$ 5,468
Operating (gain) expenses	1,958	2,077	4,126	(556)
Operating income	540	672	1,040	6,024
Interest income ⁽¹⁾	16	25	37	39
Interest expense	(131)	(176)	(292)	(406)
Other expenses, net ⁽²⁾	(2)	(14)	(3)	(41)
Income before income taxes	423	507	782	5,616
Income tax provision	156	135	297	2,211
Net income	\$ 267	\$ 372	\$ 485	\$ 3,405

(1) Includes reorganization interest income.

(2) Includes preferred dividend requirement as other expense.

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

Utility

Under cost of service ratemaking, the Utility's rates are determined based on its costs of service and are adjusted periodically to reflect differences between actual sales or demand compared to forecasted sales or demand used in setting rates. The Utility's electricity and natural gas distribution rates reflect the sum of individual revenue requirement components. 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 PG&E Corporation's and the Utility's combined 2004 Annual Report and below under "Regulatory Matters."

The Utility currently faces price and volumetric risk for the portion of intrastate natural gas transportation capacity that is not contracted under fixed reservation charges used by core customers (see further discussion in the Transportation and Storage section under Risk Management Activities of this MD&A). The Utility is also at risk for costs associated with meeting demand and maintaining electric transmission system sufficiency and reliability in the Utility's service area in excess of amounts allowed in its FERC-authorized transmission

owner rates.

Revenues collected on behalf of the DWR and the DWR's related costs are not included in the Utility's Consolidated Statements of Operations, reflecting the Utility's role as a billing and collection agent for the DWR's sales to the Utility's customers.

Electric Operating Revenues

The Utility records its electric distribution and generation revenues under cost-of-service revenue requirements approved by the CPUC in the Utility's 2003 GRC. 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.

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 shows a breakdown of the Utility's electric operating revenues.

(in millions)	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
Electric revenues	\$ 2,223	\$ 2,140	\$ 4,307	\$ 4,309
DWR pass-through revenue	(388)	(449)	(834)	(919)
Subtotal	1,835	1,691	3,473	3,390
Miscellaneous	(55)	372	(34)	461
Total electric operating revenues	\$ 1,780	\$ 2,063	\$ 3,439	\$ 3,851
Total electricity sales (in GWh) ⁽¹⁾	19,232	19,511	38,266	38,381

⁽¹⁾ Includes DWR electricity sales.

For the three months ended June 30, 2005, the Utility's electric operating revenues decreased approximately \$283 million, or 14%, compared to the same period in 2004 mainly due to the following factors:

- Electric operating revenues decreased approximately \$230 million during the three months ended June 30, 2005, as compared to the same period in 2004, primarily due to lower electricity procurement and transmission costs which are passed through to customers;
- Electric operating revenues decreased approximately \$120 million as a result of a decrease in the revenue requirement associated with the Settlement Regulatory Asset. As a result of the refinancing of the Settlement Regulatory Asset on February 10, 2005 through issuance of the ERBs, the Utility was no longer authorized to collect this revenue requirement (see further discussion in the Overview to this MD&A and Note 4 of the Notes to the Condensed Consolidated Financial Statements); and
- The approval of the Utility's 2003 GRC in May 2004 resulted in the Utility recording revenues intended to cover the six month period ended June 30, 2004 during the second quarter of 2004. As a result, although the Utility received attrition revenues to adjust for wages and inflation for the three months ended June 30, 2005 as authorized in the 2003 GRC and an increase in revenues as a result of the 2004 cost of capital proceeding, total GRC and cost of capital revenues for the three month period ended June 30, 2005 were approximately \$45 million lower than in the same period in 2004.

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

- The Utility is authorized to collect and remit a DRC from its electricity customers to repay

the ERBs until they are fully retired. Also in connection with the issuance of the ERBs, the Utility has established a balancing account, the Energy Recovery Bond Balancing Account, or ERBBA, to track various costs and benefits associated with the ERBs (see further discussion in "Regulatory Matters"). The DRC charge and revenue requirements associated with the ERBBA resulted in an approximately \$115 million electric operating revenue increase for the three months ended June 30, 2005, with no similar amount in the same period in 2004.

For the six months ended June 30, 2005, the Utility's electric operating revenues decreased approximately \$412 million, or 11%, compared to the same period in 2004 due to the following factors:

- Electric operating revenues decreased approximately \$400 million during the six months ended June 30, 2005, as compared to the same period in 2004, primarily due to lower electricity procurement and transmission costs which are passed through to customers; and
- Electric operating revenues decreased \$195 million as a result of a decrease in the revenue requirement associated with the Settlement Regulatory Asset. As a result of the refinancing of the Settlement Regulatory Asset on February 10, 2005 through issuance of the ERBs, the Utility was no longer authorized to collect this revenue requirement (see further discussion in the Overview to this MD&A and Note 4 of the Notes to the Condensed Consolidated Financial Statements).

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

- Attrition revenues as authorized in the 2003 GRC and revenues authorized in the 2004 cost of capital proceeding resulted in an increase in electric operating revenues of approximately \$60 million for the six months ended June 30, 2005, as compared to the same period in 2004; and
- The Utility's collection of the DRC charge and revenue requirements associated with the ERBBA resulted in an approximately \$135 million electric operating revenue increase for the six months ended June 30, 2005, with no similar amount in the same period in 2004.

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. The following table shows a breakdown 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 June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
Cost of purchased power	\$ 575	\$ 694	\$ 1,029	\$ 1,283
Proceeds from surplus sales allocated to the Utility	(132)	(35)	(233)	(98)
Fuel used in own generation	44	26	88	69
Total net cost of electricity	\$ 487	\$ 685	\$ 884	\$ 1,254
Average cost of purchased power per GWh	\$ 0.072	\$ 0.076	\$ 0.069	\$ 0.079
Total purchased power (GWh)	7,944	9,185	14,929	16,279

During the three and six-month periods ended June 30, 2005, the Utility produced more electricity from its own generation facilities, thereby reducing the amount of electricity the Utility was required to purchase for its customers. During the three months ended June 30, 2005, the Utility's Diablo Canyon power plant was in full operation compared to the same period in 2004 when an approximately 69 day scheduled refueling outage at Diablo Canyon required the Utility to purchase replacement power. Also, due to above average rainfall during 2005, the Utility's hydroelectric generation facilities produced more electricity. In addition, as of January 1, 2005, the Utility was no longer required to procure electricity for customers of the Western Area Power Administration. As a result, the Utility's cost of electricity decreased significantly in 2005 as compared to 2004.

During the three months ended June 30, 2005, the Utility's cost of electricity decreased approximately \$198 million, or 29%, compared to 2004, mainly due to the following factors:

- The decrease in total purchased power of 1,241 gigawatt hours, or GWh, and the decrease in the average cost of purchased power of \$0.004 per GWh in 2005 as compared to the same period in 2004 resulted in a decrease of approximately \$119 million in the cost of purchased power; and
- The increase in proceeds from surplus sales allocated to the Utility of \$97 million in the three months ended June 30, 2005, as compared to the same period in 2004, resulted in a corresponding decrease in the cost of electricity.

During the six months ended June 30, 2005, the Utility's cost of electricity decreased approximately \$370 million, or 30%, compared to 2004, mainly due to the following factors:

- The decrease in total purchased power of 1,350 GWh and the decrease in the average cost of purchased power of \$0.010 per GWh in 2005 as compared to the same period in 2004 resulted in a decrease of approximately \$254 million in the cost of purchased power; and
- The increase in proceeds from surplus sales allocated to the Utility of \$135 million in the six months ended June 30, 2005, as compared to the same period in 2004, resulted in a corresponding decrease in the cost of electricity.

Natural Gas Operating Revenues

The Utility sells natural gas and provides natural gas transportation services to its customers. The Utility's natural gas customers consist of two categories: core and noncore customers. The core customer class is comprised mainly of residential and smaller commercial natural gas customers. The noncore customer class is comprised of industrial and larger commercial natural gas customers. The Utility provides natural gas delivery services to all core and noncore 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. While the Utility provides non-core customers with delivery service, it does not provide non-core customers with natural gas supply. When the Utility provides both supply and delivery, the Utility refers to the service as natural gas bundled service. In 2004, core customers represented over 99% of the Utility's total customers and approximately 35% of its total natural gas deliveries, while noncore customers comprised less than 1% of the Utility's total customers and approximately 65% of its total natural gas deliveries.

The Utility's transportation system transports gas throughout California to the Utility's distribution system, which, in turn, delivers gas to end-use customers. Utility transportation and distribution services for all customers have historically been bundled or sold together at a combined rate.

The following table shows a breakdown of the Utility's natural gas operating revenues:

(in millions)	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
Bundled natural gas revenues	\$ 665	\$ 615	\$ 1,609	\$ 1,482
Transportation service-only revenues	53	71	118	135
Total natural gas operating revenues	\$ 718	\$ 686	\$ 1,727	\$ 1,617
Average bundled revenue per millions of Mcf of natural gas sold	\$ 11.33	\$ 12.00	\$ 9.68	\$ 9.07
Total bundled natural gas sales (in millions of Mcf)	59	51	167	163

The Utility's natural gas operating revenues increased approximately \$32 million, or 5%, during the three months ended June 30, 2005, compared to the same period in 2004 as a result of the following:

- Excluding the impact of the adjustments to 2004 revenues as a result of the 2003 GRC decision discussed below, bundled natural gas operating revenues increased approximately \$120 million, or 22%, in the three months ended June 30, 2005 as compared to the same period in 2004. This increase was primarily a result of an increase in volume of approximately eight million Mcf, or thousand cubic feet, or 16%, combined with an increase in the average bundled revenue per millions of Mcf of natural gas sold of approximately \$0.60 per millions of Mcf, or 6%, resulting from increases in the cost of natural gas, for the three months ended June 30, 2005.

Partially offsetting this increase were the following decreases:

- The approval of the 2003 GRC in May 2004 resulted in the Utility recording approximately \$50 million in revenues related to 2003 in the second quarter of 2004 with no comparable amount in 2005. Also as a result of the 2003 GRC decision, the Utility recorded approximately \$20 million in revenues related to the first quarter of 2004 in the second quarter of 2004, with no comparable amount in 2005; and
- Transportation service-only revenues decreased approximately \$18 million, or 25%, in the second quarter of 2005 as compared to the same period in 2004.

The Utility's natural gas operating revenues increased approximately \$110 million, or 7%, for the six months ended June 30, 2005 compared to the same period in 2004 as a result of the following:

- Excluding the impact of the adjustments to 2004 revenues as a result of the 2003 GRC decision discussed below, bundled natural gas operating revenues increased approximately \$177 million, or 12%, in the six months ended June 30, 2005 as compared to the same period in 2004. This increase was primarily a result of an increase in the average bundled revenue per millions of Mcf of natural gas sold of approximately \$0.85 per millions of Mcf, or 10%, resulting from increases in the cost of natural gas, combined with an increase in volume of approximately four million Mcf, or 2%, for the six months ended June 30, 2005.

Partially offsetting this increase were the following decreases:

- The approval of the 2003 GRC in May 2004 resulted in the Utility recording approximately \$50 million in revenues related to 2003 in the second quarter of 2004 with no comparable amount in 2005; and
- Transportation service-only revenues decreased approximately \$17 million, or 13%, in the six months ended June 30, 2005 as compared to the same period in 2004.

Cost of Natural Gas

The Utility's cost of natural gas includes the costs to purchase natural gas and the costs to transport natural gas on interstate pipelines, but excludes the costs associated with the Utility's intrastate pipeline, which are included in operating and maintenance expense. The following table shows a breakdown of the Utility's cost of natural gas:

(in millions)	Three Months Ended June 30		Six Months Ended June 30,	
	2005	2004	2005	2004
Cost of natural gas sold	\$ 313	\$ 247	\$ 896	\$ 790
Cost of natural gas transportation	34	31	71	67
Total cost of natural gas	\$ 347	\$ 278	\$ 967	\$ 857
Average cost per millions of Mcf of natural gas sold	\$ 5.31	\$ 4.84	\$ 5.37	\$ 4.85
Total natural gas sold (in millions of Mcf)	59	51	167	163

In the three months ended June 30, 2005, the Utility's total cost of natural gas increased approximately \$69 million, or 25%, compared to the same period in 2004 primarily due to an increase in the average market price of natural gas purchased of approximately \$0.47 per millions of Mcf, or 10%, combined, with an increase in volume of 8 million Mcf, or 16%.

In the six months ended June 30, 2005, the Utility's total cost of natural gas increased approximately \$110 million, or 13%, compared to the same period in 2004 primarily due to an increase in the average market price of natural gas purchased of approximately \$0.52 per millions of Mcf, or 11%, combined with an increase in volume of 4 million Mcf, or 2%.

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.

During the three months ended June 30, 2005, the Utility's operating and maintenance expenses decreased by approximately \$78 million, or 10%, as compared to the same period in 2004, mainly due to the following factors:

- Operating and maintenance expenses decreased approximately \$40 million at Diablo Canyon in the three months ended June 30, 2005, as compared to the same period in 2004, reflecting the scheduled refueling outage in the second quarter of 2004 with no similar refueling outage in the same period in 2005; and
- Operating and maintenance expenses decreased approximately \$15 million for the three months ended June 30, 2005, as compared to the same period in 2004 due to decreases in employee benefit plan related expenses in 2005.

During the six months ended June 30, 2005, the Utility's operating and maintenance expenses decreased by approximately \$116 million, or 7%, as compared to the same period in 2004, mainly due to the following factors:

- Operating and maintenance expenses decreased approximately \$30 million related to the various provisions of the Settlement Agreement, including obligations to invest in clean energy technology and the donation of land in 2004, with no similar amounts for the same period in 2005;
- Operating and maintenance expenses decreased approximately \$50 million at Diablo Canyon in the six months ended June 30, 2005, as compared to the same period in 2004, reflecting the scheduled refueling outage in the six months ended June 30, 2004, with no similar refueling outage in the same period in 2005; and
- Operating and maintenance expenses decreased approximately \$30 million for the six months ended June 30, 2005, as compared to the same period in 2004, due to expenses paid on behalf of the CPUC for its professional fees incurred in connection with the Chapter 11 proceeding with no similar amount in 2005.

Recognition of Regulatory Assets

In light of the satisfaction of various conditions to the implementation of the Utility's plan of reorganization, the Utility recorded the regulatory assets provided for under the settlement agreement in the first quarter of 2004. This resulted in the recognition of a one-time non-cash, pre-tax gain of \$3.7 billion for the Settlement Regulatory Asset and \$1.2 billion for the Utility retained generation regulatory assets, for a total after-tax gain of \$2.9 billion.

Depreciation, Amortization and Decommissioning

In the three months ended June 30, 2005, the Utility's depreciation, amortization and decommissioning expenses increased by approximately \$102 million, or 29%, compared to the same period in 2004, primarily as a result of the following factors:

- The Utility recorded approximately \$60 million for amortization of the ERB regulatory asset with no similar amount in 2004;
- As a result of the 2003 GRC decision in May 2004 authorizing lower depreciation rates, the Utility recorded an approximately \$37 million decrease to depreciation expense related to 2003 in the second quarter of 2004 with no similar reduction in the same period in 2005. The Utility also recorded an approximately \$20 million reduction to depreciation expense related to the first quarter of 2004 during the second quarter of 2004 as a result of the 2003 GRC decision with no similar reduction in 2005; and
- Depreciation expense increased approximately \$10 million as a result of plant additions during the three months ended June 30, 2005.

Partially offsetting these increases was a decrease in decommissioning expense during the three months ended June 30, 2005, as compared to the same period in 2004. The Utility recorded approximately \$30 million for decommissioning expense relating to 2003 as authorized in the 2003 GRC decision in May 2004, with no similar amount in the three months ended June 30, 2005.

In the six months ended June 30, 2005, the Utility's depreciation, amortization and decommissioning expenses increased by approximately \$189 million, or 29%, compared to the same period in 2004, primarily as a result of the following factors:

- The Utility recorded approximately \$70 million for amortization of the ERB regulatory asset with no similar amount in 2004;
- Amortization of the settlement regulatory assets increased approximately \$50 million in the six months ended June 30, 2005 as compared to the same period in 2004. This increase is mainly due to the settlement regulatory assets being amortized over a three-month period in 2004 as compared to a six-month period in 2005 combined with a change in the amortization methodology. In 2004 and prior to the issuance of the ERBs in 2005, the Settlement Regulatory Asset was amortized mortgage-style over a nine year period. After issuance of the ERBs, amortization of the Settlement Regulatory Asset fluctuates based on the DRC charge, which changes throughout the year due to fluctuations in volume and seasonality, and various expenses associated with the ERBs (see further discussion in "Regulatory Matters");
- As a result of the 2003 GRC decision in May 2004 authorizing lower depreciation rates, the Utility recorded an approximately \$37 million decrease to depreciation expense related to 2003 in the second quarter of 2004 with no similar reduction in the six months ended June 30, 2005; and
- Depreciation increased approximately \$20 million as a result of plant additions during the six months ended June 30, 2005.

Interest Income

In the three months ended June 30, 2005, interest income, including reorganization interest income, decreased by approximately \$3 million, or 13%, compared to the same period in 2004 primarily due to interest income recorded to the ERBBA (see further discussion in "Regulatory Matters") retroactive to February 10, 2005 upon issuance of the ERBs.

In the six months ended June 30, 2005, interest income, including reorganization interest income, increased by approximately \$5 million, or 15%, compared to the same period in 2004. This increase is a result of an increase in rates during the period partially offset by interest recorded to the ERBBA as discussed above.

The Utility discontinued reporting in accordance with the American Institute of Certified Public Accountants' Statement of Position 90-7, "Financial Reporting by Entities in Reorganization Under the Bankruptcy Code," or SOP 90-7, upon its emergence from Chapter 11. Prior to that date, the Utility reported reorganization interest income separately on its Consolidated Statements of Income. Reorganization income reported in 2004 mainly included interest earned on cash accumulated during the Utility's Chapter 11 proceedings.

Interest Expense

In the three months ended June 30, 2005, the Utility's interest expense decreased by approximately \$34 million, or 22%, compared to the same period in 2004, primarily as a result of interest recorded to the ERBBA as a result of settlements with various power suppliers (see "Regulatory Matters" and Note 7 of the Notes to the Condensed Consolidated Financial Statements).

In the six months ended June 30, 2005, the Utility's interest expense decreased by approximately \$94 million, or 25%, compared to the same period in 2004 primarily due to a lower average amount of debt outstanding and as a result of settlements with various power suppliers as discussed above.

Income Tax Expense

In the three months ended June 30, 2005, the Utility's tax expense increased approximately \$7 million, or 4%, compared to the same period in 2004, mainly due to the tax effects of a tax regulatory asset related to the 2003 GRC recorded in the second quarter of 2004, offset by a decrease in pre-tax income of approximately \$129 million for the three months ended June 30, 2005.

In the six months ended June 30, 2005, the Utility's tax expense decreased approximately \$2 billion, or 86%, compared to the same period in 2004, mainly due to a decrease in pre-tax income of \$4.9 billion for the six months ended June 30, 2005. This decrease is primarily the result of the recognition of regulatory assets associated with the Settlement Agreement for the six months ended June 30, 2004, with no similar amount recognized in the same period in 2005.

PG&E Corporation, Eliminations and Others

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 affiliates. These allocations are made without mark-up. Operating expenses allocated to affiliates are eliminated in consolidation.

In the three months ended June 30, 2005, PG&E Corporation's operating expenses decreased by \$10 million compared to the same period in 2004, primarily due to a reduction of general and administrative expenses retained at PG&E Corporation. The decrease in operating expenses of approximately \$25 million for the six months ended June 30, 2005, compared to the same period in 2004, was primarily due to the receipt of insurance proceeds for legal costs and a reduction in general and administrative expenses retained at PG&E Corporation.

Interest Expense

PG&E Corporation's interest expense is not allocated to its affiliates. In the second quarter of 2005, PG&E Corporation's interest expense decreased by approximately \$11 million, or 61%, compared to the same period in 2004. For the six months ended June 30, 2005, PG&E Corporation's interest expense decreased by approximately \$20 million, or 59%, compared to the same period in 2004. The decreases during these periods compared to the same periods in 2004 were primarily due to a reduction in the amount of outstanding debt, due to the redemption of PG&E Corporation's 6 $\frac{7}{8}$ % Senior Secured Notes due 2008, \$600 million principal amount, on November 15, 2004.

Other Income (Expense)

PG&E Corporation's other expense decreased by approximately \$30 million, or 88%, and \$60 million, or 90%, in the three and six months ended June 30, 2005, respectively, compared to the same periods in 2004. These decreases were primarily due to a reduction in the pre-tax charge to earnings, related to the changes in market value of non-cumulative dividend participation rights included within PG&E Corporation's Convertible Subordinated Notes in 2004.

LIQUIDITY AND FINANCIAL RESOURCES

Overview

The level of PG&E Corporation's and the Utility's current assets and current liabilities is subject to fluctuation 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.

With the achievement of a 52% equity ratio in January 2005, the Utility reinstated the payment of a regular quarterly dividend. In addition, during the six months ended June 30, 2005, the Utility used cash (including the ERB proceeds) in excess of amounts needed for operations, debt service and repayment, base capital expenditures, and the payment of a quarterly dividend, to repurchase common stock. In turn, PG&E Corporation used the cash received from the Utility in the form of dividends and share repurchases to recommence the payment of a regular quarterly dividend and repurchase common stock from shareholders.

Liquidity

PG&E Corporation and the Utility intend to retain sufficient cash for operating needs and to manage debt levels to maintain access to credit. PG&E Corporation and the Utility target cash balances, which together with credit facilities, accommodate normal and unforeseen demands on its liquidity.

At June 30, 2005, PG&E Corporation and its subsidiaries had consolidated cash and cash equivalents of approximately \$1.5 billion, and restricted cash of approximately \$1.7 billion. PG&E Corporation and the Utility maintain separate bank accounts. At June 30, 2005, PG&E Corporation on a stand-alone basis had cash and cash equivalents of approximately \$354 million. At June 30, 2005, the Utility had cash and cash equivalents of approximately \$1.1 billion, and restricted cash of approximately \$1.7 billion. The Utility's restricted cash includes amounts deposited in escrow related to the remaining disputed Chapter 11 claims, collateral required by the ISO and deposits under certain third party agreements.

PG&E Corporation and the Utility primarily invest their cash in money market funds and in short-term obligations of the U.S. Government and its agencies.

The Utility seeks to maintain or strengthen its credit ratings to provide efficient access to financial and trade credit and to ensure adequate liquidity. As of June 30, 2005, PG&E Corporation's and the Utility's credit ratings from Standard & Poor's Rating Service, or S&P, and Moody's Investors Service, or Moody's, were as follows:

	Moody's	S&P
Utility		
Corporate credit rating	Baa1 ⁽¹⁾	BBB ⁽²⁾

Senior unsecured debt	Baa1 ⁽³⁾⁽⁴⁾	BBB ⁽³⁾
Pollution control bonds backed by bond insurance	Aaa	AAA
Pollution control bonds backed by Letters of Credit	--	AA-/A-1+
Credit facility	--	BBB
Preferred Stock	Baa3 ⁽⁵⁾	BB+ ⁽⁵⁾

PG&E Funding LLC

Rate Reduction Bonds	Aaa	AAA
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PG&E Energy Recovery Funding LLC

Energy Recovery Bonds	Aaa	AAA
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PG&E Corporation

Corporate credit rating	Baa3	-- ⁽²⁾
Credit facility	Baa3 ⁽⁶⁾	--

1. Upgraded on March 3, 2005 from Baa3.
2. Upgraded on February 16, 2005 from BBB-. S&P has not assigned a rating to PG&E Corporation.
3. Affirmed BBB senior secured rating on February 16, 2005. As discussed in Note 3 in the Notes to the Condensed Consolidated Financial Statements, on April 22, 2005, the lien of the indenture securing the First Mortgage Bonds was released following confirmation by Moody's and S&P that the Utility's unsecured debt would be rated BBB by S&P and Baa1 by Moody's after the release of the lien.
4. Upgraded on March 3, 2005 from (P)Baa3.
5. Upgraded on March 3, 2005 from Ba2 by Moody's and on February 16, 2005 from BB by S&P.
6. Assigned on March 3, 2005.

PG&E Corporation and the Utility have taken advantage of recent favorable market conditions by completing the following transactions:

- On April 8, 2005, the Utility refinanced its existing \$850 million working capital facility with a \$1 billion working capital facility that has a term of 5 years, reduced fees and applicable margins, and less restrictive covenants;
- On April 22, 2005, the Utility entered into an amendment to four reimbursement agreements totaling \$620 million related to letters of credit that had been issued to support certain pollution control bonds aggregating \$614 million issued on behalf of the Utility. In addition to containing more favorable provisions, the term of the amended agreements has been extended from three years to five years until April 22, 2010;
- On May 24, 2005, the Utility entered into seven separate loan agreements with the California Infrastructure and Economic Development Bank to issue seven series of tax-exempt pollution control bonds, or PC Bonds Series A-G, of approximately \$454 million. The funds received by the Utility were used to repay an approximately \$454 million loan outstanding under the \$1 billion working capital facility; and
- On April 8, 2005, PG&E Corporation's unsecured \$200 million credit facility was amended to include an extended 5-year term, expiring on December 10, 2009 and to conform the provisions regarding covenants, representations and events of default to those contained in the Utility's \$1 billion working capital facility.

Currently, PG&E Corporation and the Utility have credit facilities totaling \$200 million and \$1.65 billion, respectively.

On July 26, 2005, the Utility sent notice to holders of all of the outstanding shares of the Utility's 7.04% Redeemable First Preferred Stock, totaling approximately \$36 million aggregate par value, that the issue will be redeemed on August 31, 2005. In addition to the \$25.70

per share redemption price, holders of the 7.04% Redeemable First Preferred Stock will be entitled to receive an amount equal to all accumulated and unpaid dividends on such shares to and including August 31, 2005.

Dividends

On June 15, 2005, the Board of Directors of the Utility declared a dividend of approximately \$118 million that was paid on June 16, 2005 to PG&E Corporation and PG&E Holdings LLC, a wholly owned subsidiary of the Utility that held approximately 7% of the Utility's common stock.

Also, on June 15, 2005, the Board of Directors of PG&E Corporation declared a quarterly common stock dividend of \$0.30 per share to shareholders of record on June 30, 2005. On July 15, 2005 PG&E Corporation paid this dividend totaling approximately \$119 million, of which approximately \$7 million was paid to Elm Power Corporation, a wholly owned subsidiary of PG&E Corporation. In addition, PG&E Corporation paid approximately \$6 million in dividend equivalent payments to Convertible Subordinated Note holders of record on June 30, 2005.

PG&E Corporation charged dividends declared to Accumulated Earnings and the Utility charged dividends declared to Reinvested Earnings.

Stock Repurchases

On February 22, 2005, under an accelerated share repurchase arrangement entered into on December 15, 2004, PG&E Corporation paid GS&Co. approximately \$14 million as a price adjustment based on the daily volume weighted average price, or VWAP, of PG&E Corporation common stock over the term of the arrangement. PG&E Corporation charged the payment to Common Stock within Common Shareholders' Equity.

On March 4, 2005, PG&E Corporation entered into an accelerated share repurchase arrangement with GS&Co. under which PG&E Corporation repurchased 29,489,400 shares of its common stock at an initial price of \$35.60 per share (for an aggregate amount including commissions of approximately \$1.05 billion). The repurchase was funded from available cash on hand and the repurchased shares were retired. PG&E Corporation charged approximately \$460 million to Common Stock and approximately \$591 million to Accumulated Earnings within Common Shareholders' Equity in respect of these transactions. Under the share forward component of the arrangement, or March 4, 2005 arrangement, certain payments were required by both PG&E Corporation and GS&Co. upon termination. Most significantly, PG&E Corporation was to receive from, or be required to pay to, GS&Co. a price adjustment on the repurchased shares based on the difference between the amount it paid and the VWAP over the approximately six month intended arrangement period. Upon an early termination of the March 4, 2005 arrangement, PG&E Corporation was required to compensate GS&Co. for its losses in connection with the arrangement unless the termination event resulted from the declaration of a dividend and a new share forward was executed to complete the March 4, 2005 arrangement. As discussed below, on June 15, 2005, the Board of Directors of PG&E Corporation declared a cash dividend on PG&E Corporation common stock for the second quarter of 2005.

Thus, on June 16, 2005, PG&E Corporation entered into a new share forward with GS&Co., or June 16, 2005 arrangement, based on 11,430,000 shares to complete the balance of the March 4, 2005 arrangement. The net of the amounts payable between the parties under the March 4, 2005 arrangement, including the amount of the price adjustment based on the VWAP, was approximately \$78,000 and was paid to GS&Co., at PG&E Corporation's option in cash, on June 30, 2005.

The June 16, 2005 arrangement is substantially identical to the March 4, 2005 arrangement, requiring certain payments by both PG&E Corporation and GS&Co. As with the March 4, 2005 arrangement, the most significant of these payments is the price adjustment with respect to the 11,430,000 shares based on the difference between the \$35.60 purchase price per share and the VWAP over a period expected to extend to early September 2005. The price adjustment and any additional payments that PG&E Corporation may make under the June 16, 2005 arrangement can be settled, at PG&E Corporation's option, in cash or in shares of its common stock, or a combination of the two. Therefore, PG&E Corporation accounts for its payment obligations as equity.

Until the June 16, 2005 arrangement is completed or terminated, generally accepted accounting principles in the United States of America, or GAAP, requires PG&E Corporation to assume that it will issue shares to settle its obligations (up to a maximum of 22,860,000 shares). PG&E Corporation must calculate the number of shares that would be required to satisfy its obligations upon completion of the June 16, 2005 arrangement based on the market price of PG&E Corporation's common stock at the end of a reporting period. The number of shares that would be required to satisfy the obligations must be treated as outstanding for purposes of calculating diluted earnings per share. Based on the market price of PG&E Corporation stock at June 30, 2005, PG&E Corporation would have an obligation to GS&Co. of approximately \$25.3 million upon completion of the June 16 arrangement. Accordingly, approximately 674,000 additional shares of PG&E Corporation common stock attributable to the accelerated repurchase arrangement were treated as outstanding for purposes of calculating diluted earnings per share.

On March 8, 2005, the Utility used proceeds from the issuance of ERBs (discussed in Note 4) to repay debt and to repurchase 22,023,283 shares of its common stock from PG&E Corporation for an aggregate purchase price of approximately \$960 million. The Utility had repurchased \$960 million of its common stock as of June 30, 2005. The Utility recognized charges of approximately \$141 million to Additional Paid-in Capital, approximately \$110 million to Common Stock, and approximately \$709 million to Reinvested Earnings within Shareholders' Equity in respect of this transaction.

The Utility anticipates that it will use some of the proceeds from the second series of ERBs anticipated to be issued in November 2005, along with expected generator refunds, and additional estimated cash on hand of approximately \$200 million, to repurchase additional shares of its common stock. In turn, PG&E Corporation anticipates that it would use the amounts received from the Utility to repurchase a total of \$1.8 billion of its common stock in 2005, increased from the previous estimate of \$1.6 billion. Of this total, PG&E Corporation has used \$1.05 billion to enter into the accelerated share repurchase arrangements described above. Additional repurchases are subject to authorization by the Board of Directors, except for shares repurchased with net cash proceeds received by PG&E Corporation upon exercise of stock options. The ultimate amount of stock repurchased by PG&E Corporation in 2005 will depend upon the aggregate amount of the second series of ERBs and the amount of any generator refunds received in cash by the Utility.

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 six months ended June 30, 2005 and 2004 were as follows:

(in millions)	Six Months Ended June 30,	
	2005	2004
Net income	\$ 499	\$ 3,486
Non-cash (income) expenses:		
Depreciation, amortization and decommissioning	839	650
Recognition of regulatory assets, net of tax	-	(2,904)
Other deferred charges and noncurrent liabilities	(83)	79
Change in accounts payable	(222)	170
Change in regulatory balancing accounts, net	565	(440)
Other uses of cash:		
Payments authorized by the bankruptcy court on amounts classified as liabilities subject to compromise	-	(1,022)
Other changes in operating assets and liabilities	6	508
Net cash provided by operating activities	\$ 1,604	\$ 527

Net cash provided by operating activities increased by approximately \$1.08 billion during the six months ended June 30, 2005 compared to the same period in 2004. This is mainly due to the following factors:

- Regulatory balancing accounts increased by approximately \$1 billion in 2005. This is primarily due to an increase in various settlements recorded by the Utility in the balancing accounts as well as seasonality affecting usage;
- Other deferred charges and noncurrent liabilities decreased by approximately \$160 million in 2005 mostly due to costs associated with the issuance of long-term debt in 2004 with no similar amount in 2005;
- Accounts payable decreased by approximately \$390 million in 2005 primarily due to decreases in power and gas purchases;
- Other operating assets and liabilities decreased by approximately \$500 million; and
- Payments authorized by the bankruptcy court on amounts classified as liabilities subject to compromise decreased by approximately \$1.0 billion in 2005. On the effective date of the Utility's plan of reorganization, the Utility paid all allowed creditor claims, with no comparable amount in 2005.

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 six months ended June 30, 2005 and 2004. Year to year variances depend upon the amount and type of

construction activities, which can be influenced by storm and other factors.

The Utility's cash flows from investing activities for the six month periods ended June 30, 2005 and 2004 were as follows:

(in millions)	Six Months Ended June 30,	
	2005	2004
Capital expenditures	\$ (803)	\$ (737)
Net proceeds from sale of assets	17	25
Decrease (increase) in restricted cash	321	(1,741)
Other investing activities, net	12	(54)
Net cash used in investing activities	\$ (453)	\$ (2,507)

Net cash used in investing activities decreased by approximately \$2.05 billion during the six months ended June 30, 2005 compared to the same period in 2004 mostly due to an increase in restricted cash of approximately \$2 billion in 2004, with no such amount in 2005. In 2004, funds were deposited into escrow to pay disputed claims when resolved.

Financing Activities

In 2005, the Utility obtained \$1.9 billion of proceeds from the ERBs, which refinanced a portion of the Settlement Regulatory Asset. It used the proceeds to repay debt and repurchase equity.

The Utility's cash flows from financing activities for the six month periods ended June 30, 2005 and 2004 were as follows:

(in millions)	Six Months Ended June 30,	
	2005	2004
Repayments under credit facilities and short-term borrowing	\$ (300)	\$ -
Proceeds from long-term debt issued	451	6,892
Net proceeds from energy recovery bonds issued	1,874	-
Long-term debt matured, redeemed, or repurchased	(1,354)	(7,098)
Rate reduction bonds matured	(141)	(141)
Energy recovery bonds matured	(14)	-
Common stock dividends paid	(220)	-
Preferred dividends paid	(8)	(88)
Preferred stock with mandatory redemption provisions redeemed	(122)	(11)
Common stock repurchased	(960)	-
Net cash used in financing activities	\$ (794)	\$ (446)

For the six months ended June 30, 2005, net cash used in financing activities increased by approximately \$348 million compared to the same period in 2004, mainly due to the following factors:

- During the first quarter of 2005, the Utility repaid \$300 million it borrowed under its \$850 million working capital facility;
- In 2004, in connection with the Utility's plan of reorganization, the Utility issued approximately \$6.9 billion, net of issuance costs, in long-term debt. On May 24, 2005, the Utility entered into seven loan agreements with the California Infrastructure and Economic Development Bank to issue PC Bonds Series A-G, totaling \$451 million, net of issuance costs of \$3 million. As a result, long-term debt issued decreased by approximately \$6.4 billion in 2005;
- In February 2005, PERF issued approximately \$1.9 billion of ERBs with no similar issuance in 2004 (see Note 4 of the Notes to the Condensed Consolidated Financial Statements for further discussion). In March 2005, the Utility used proceeds from the issuance of ERBs to repurchase \$960 million of its common stock from PG&E Corporation;
- In January 2005, the Utility partially redeemed Floating Rate First Mortgage Bonds due in

2006 in the aggregate principal amount of \$300 million, and on February 24, 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 the Utility entered into in April 2004 when its plan of reorganization under Chapter 11 became effective. During the second quarter of 2004, repayments on long-term debt totaled approximately \$7 billion. As a result, repayments on long-term debt decreased approximately \$5.7 billion;

- During the six months ended June 30, 2005, the Utility paid \$220 million in common stock dividends to PG&E Corporation and \$14 million to PG&E Holdings LLC, a wholly owned subsidiary of the Utility; and
- During the six months ended June 30, 2005, the Utility redeemed \$122 million of preferred stock with mandatory redemption provisions and it is now fully redeemed compared to \$11 million in 2004.

PG&E Corporation

As of June 30, 2005, 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. The Utility paid a cash dividend of \$118 million to PG&E Corporation and PG&E Holdings LLC on June 16, 2005. The Utility did not pay any dividends to, nor repurchase shares from, PG&E Corporation during 2004.

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's consolidated cash flows from operating activities for the six month periods ended June 30, 2005 and 2004 were as follows:

(in millions)	Six Months Ended June 30,	
	2005	2004
Net income	\$ 485	\$ 3,405
Non-cash (income) expenses:		
Depreciation, amortization and decommissioning	839	651
Deferred income taxes and tax credits, net	(115)	2,053
Recognition of regulatory asset, net of tax	-	(4,900)
Other deferred charges and noncurrent liabilities	(75)	12
Tax benefit on employee stock option exercises	37	-
Other changes in operating assets and liabilities	412	(603)
Net cash provided by operating activities	\$ 1,583	\$ 618

Net cash provided by operating activities increased by approximately \$965 million during the six months ended June 30, 2005, compared to the same period in 2004. This increase was primarily related to an increase in the Utility's net cash provided by operating activities as discussed above, the recognition of tax benefits on the exercise of employee stock options during the six months ended June 30, 2005, with no similar amount in 2004, and the payment of approximately \$84 million to participating individuals in the senior executive retention program in January 2004, with no similar payment in 2005.

Investing Activities

On March 8, 2005, PG&E Corporation received \$960 million in proceeds for the repurchase of 22,023,283 shares of Utility common stock by the Utility. This transaction was eliminated in consolidation. PG&E Corporation, on a stand-alone basis, did not have any other material investing activities during the six months ended June 30, 2005 or the same period in 2004.

Financing Activities

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

PG&E Corporation's consolidated cash flows from financing activities for the six month periods ended June 30, 2005 and 2004 were as follows:

(in millions)	Six Months Ended June 30,	
	2005	2004
Repayments under credit facilities and short-term borrowings	\$ (300)	\$ -
Net proceeds from issuance of energy recovery bonds	1,874	-
Net proceeds from issuance of long-term debt	451	6,892
Long-term debt matured, redeemed or repurchased	(1,356)	(7,098)
Rate reduction bonds matured	(141)	(141)
Energy recovery bonds matured	(14)	-
Preferred stock with mandatory redemption provisions redeemed	(122)	(11)
Common stock issued	190	97
Common stock repurchased	(1,065)	-
Preferred dividends paid	(8)	(88)
Common stock dividends paid	(111)	-
Other, net	(6)	-
Net cash used in financing activities	\$ (608)	\$ (349)

PG&E Corporation's net cash used in financing activities increased by \$259 million for the six months ended June 30, 2005, compared to the same period in 2004. The decrease was primarily related to the Utility's financing activities as discussed above, PG&E Corporation's repurchase of approximately 29.5 million shares of PG&E common stock under accelerated share repurchase agreements in March 2005 at an initial purchase price of \$1.05 billion, and the first quarter dividend payment. As discussed above, the Utility's repurchase of its common stock from PG&E Corporation totaling \$960 million in March 2005 was eliminated in consolidation.

CONTRACTUAL COMMITMENTS

PG&E Corporation and the Utility enter into contractual obligations and commitments in connection with business activities. These obligations need to be funded in the future and 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 Note 7 in the Notes to the Condensed Consolidated Financial Statements and PG&E Corporation's and the Utility's combined 2004 Annual Report for further discussion.

Utility

The Utility's contractual commitments include power purchase agreements (including agreements with qualifying facilities, irrigation districts and water agencies, and renewable energy providers), natural gas supply and transportation agreements, nuclear fuel agreements, operating leases, and other commitments.

Capital Expenditures

The Utility's investment in plant and equipment is necessary to replace aging and obsolete equipment and accommodate anticipated electricity and natural gas load growth. It is estimated that the Utility's capital expenditures will approximate \$1.9 billion in each of 2005 and 2006 (excluding potential investments in advanced metering infrastructure, as discussed below).

Advanced Metering Infrastructure

The CPUC is assessing the viability of implementing an advanced metering infrastructure for residential and small commercial customers. This infrastructure would enable California investor-owned electric utilities to measure usage of electricity on a time-of-use basis and to charge demand responsive rates. The goal of demand responsive rates is to encourage customers to reduce energy consumption during peak demand periods and to reduce peak period procurement costs. Advanced meters can record usage in time intervals and be read remotely. The Utility is implementing demand responsive tariffs for large industrial customers who already have advanced metering systems in place, and a statewide pilot program was recently completed to test whether and how much residential and small commercial customers will respond to demand responsive rates. On March 15, 2005, the Utility filed an application with the CPUC to spend up to \$49 million on pre-deployment activities for advanced metering. This application has not yet been approved, however a decision is expected in Fall 2005. On June 16, 2005, the Utility filed with the CPUC an application for deployment of its full advanced metering infrastructure project at an estimated cost of \$1.46 billion consisting of an estimated capital cost of \$1.26 billion, estimated expense of \$213 million, and a present value revenue requirement of \$2,227 million, based on a five year installation schedule for virtually all of the Utility's electric and gas customers starting in 2006. The Utility's application indicated, however, that the incremental revenue requirement (after operational savings are taken into account) will be approximately a one percent increase to the Utility's combined gas and electric revenue requirement. Over time, the advanced metering project

benefits are expected to have a positive (reduction) impact on rates as reduction in procurement-related costs due to demand response are reflected in the total costs to customers and as other uses and benefits of advanced metering infrastructure are developed. The schedule in this proceeding calls for a final CPUC decision to be issued in May 2006.

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 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 reimbursement agreements, aspects of PG&E Corporation's accelerated share repurchase program, and PG&E Corporation's guarantee related to certain National Energy & Gas Transmission, or NEGT, indemnity obligations and the Utility's workers' compensation obligations, see Notes 3, 5, and 7 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 7 in the Notes to the Condensed Consolidated Financial Statements for further discussion.

Regulatory Matters

This section of the MD&A discusses significant regulatory issues pending before the CPUC, the FERC, or the NRC, the resolution of which may affect the Utility's and PG&E Corporation's financial condition or results of operations. The information presented below should be read in conjunction with PG&E Corporation's and the Utility's combined 2004 Annual Report.

Cost of Capital Proceeding

Under the Settlement Agreement, the Utility is entitled to earn an ROE of 11.22% on an authorized 52% equity ratio until the Utility's long-term issuer credit ratings are at least A- from S&P or A3 from Moody's. The Utility's current long-term issuer credit ratings are BBB from S&P and Baa1 from Moody's.

On May 9, 2005, the Utility filed a cost of capital application with the CPUC 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 rate base for 2006. In the cost of capital proceeding, the CPUC (1) establishes the proportions of common equity, preferred equity, and debt that will comprise the Utility's total authorized capital structure for a specific year, and (2) establishes the rate of return that the Utility is authorized to earn on the common equity, preferred equity, and debt components of its capital structure. The following table compares the currently authorized amounts for 2005 and the requested amounts for 2006:

	2005 Authorized			2006 Requested		
	Cost	Capital Structure	Weighted Cost	Cost	Capital Structure	Weighted Cost
Long-term debt.....	6.10%	45.5%	2.78%	6.05%	46.0%	2.78%
Preferred stock.....	6.42%	2.5%	0.16%	5.87%	2.0%	0.12%
Common equity.....	11.22%	52.0%	5.83%	11.50%	52.0%	5.98%
Return on rate base.....			8.77%			8.88%

The Utility's proposed cost of capital would increase the 2006 cost of capital revenue requirement by approximately \$22 million over the currently authorized revenue requirement for electricity and natural gas distribution and electricity generation operations, based on the Utility's currently authorized rate base.

The Utility did not include a request for a 2006 rate of return for its electric transmission operations in this application to the CPUC because the FERC regulates electric transmission rates. Also, the Utility did not include a request for a 2006 rate of return for its gas transmission and storage operations because the CPUC previously set revenue requirements for the Utility's gas transmission and storage assets through 2007 in a separate proceeding.

The Utility has proposed that any changes to its revenue requirement resulting from adjustments to its authorized 2006 cost of capital be effective January 1, 2006. The Utility expects the CPUC will issue a final decision on this proceeding by the end of 2005.

Energy Recovery Bond Balancing Account

In connection with the Settlement Agreement, PG&E Corporation and the Utility agreed to seek to refinance the unamortized portion

of the Settlement Regulatory Asset and associated federal and state income and franchise taxes, in an aggregate principal amount of up to \$3.0 billion in two separate series up to one year apart, using a securitized financing supported by a dedicated rate component, or DRC. On February 10, 2005, PERF issued approximately \$1.9 billion of ERBs. It is anticipated that the second series would be issued in November 2005 in the aggregate amount of approximately \$800 million.

In connection with the issuance of the ERBs, the Utility has established a balancing account, the ERBBA, as authorized by the CPUC, to track various costs and benefits associated with the ERBs. The ERBBA tariff was approved by the CPUC on May 4, 2005. 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 second series of ERBs is issued. The energy supplier refunds that the Utility receives between the issuance of the first and second series of ERBs will be 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 June 30, 2005, the Utility had accrued approximately \$1.3 billion of net disputed claims filed by various energy suppliers in its Chapter 11 proceeding. The Utility has credited approximately \$385 million to the ERBBA as of June 30, 2005 as a result of energy supplier settlements after deduction for net interest costs of approximately \$70 million related to net disputed claims. The amount of this credit will reduce the estimated amount of the second series of ERBs to approximately \$800 million subject to the approval of the CPUC financing team. The Utility reserved approximately \$50 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, pending recovery.

The proceeds of the second series of ERBs will be paid by PERF to the Utility to pre-fund the Utility's tax liability that will be due as the Utility collects the DRC from its customers over the term of the first series of ERBs. Until taxes are fully paid, the Utility will compensate customers for the use of the ERB proceeds as well as for the use of the after-tax proceeds of energy supplier refunds received before the second series of ERBs is issued. The carrying cost to be credited to customers will be computed at the Utility's authorized rate of return on rate base. It is estimated that the carrying cost credit, assuming the principal amount of the second series of ERBs is \$800 million and energy supplier refunds of approximately \$385 million (\$230 million, after-tax) are received before the ERBs are issued, would be approximately \$125 million in 2006. The equity portion of this carrying cost credit, of approximately \$55 million, would reduce 2006 net income. The actual amount will depend on the principal amount of the second series of ERBs and the after-tax amount of energy supplier refunds received by the Utility before the second series of ERBs is issued. The carrying cost credit and the resulting reduction to net income will decline as the taxes are paid, reaching zero in 2012 when the ERBs and related taxes are paid in full.

Electricity Generation Resources

Procurement Cost Balancing Account and Mandatory Rate Adjustments

California law allows the Utility to recover its reasonably incurred wholesale electricity procurement costs. The Energy Resource Recovery Account, or ERRA, a balancing account authorized by the CPUC, tracks the difference between the authorized revenue requirement and the actual costs incurred under the Utility's authorized electricity resource procurement plans, excluding the costs associated with the DWR allocated contracts and certain other items. The CPUC must review the revenues and costs recorded in the ERRA at least semi-annually and adjust retail electricity rates or order refunds, as appropriate, when the forecast aggregate over-collections or under-collections exceed 5% of the Utility's prior year electricity procurement revenues, excluding amounts collected for the DWR allocated contracts. As of June 30, 2005, the ERRA had an over-collected balance of approximately \$189 million. On July 12, 2005, the CPUC approved the Utility's 2005 ERRA trigger amount of approximately \$164 million. On July 15, 2005, the Utility filed an application to address its current overcollection in the ERRA. Because the Utility projects its ERRA balance overcollection will decrease below the 5% level by 2005 year end, the Utility does not propose an ERRA rate change as part of this application. In February 2005, the CPUC approved the 2005 ERRA revenue requirement of \$2.14 billion based on forecast costs. In June 2005, the Utility filed its 2006 ERRA revenue requirement of \$2.41 billion. A final decision on the 2006 ERRA revenue requirement is expected before the end of 2005.

The CPUC performs periodic compliance reviews of the procurement activities recorded in the ERRA to ensure that the Utility's procurement activities are in compliance with its approved procurement plans. The cost of procurement activities could be disallowed up to a maximum of two times the Utility's administration costs associated with procurement each year. For 2005, this amount is \$36 million. In April 2005, the CPUC approved the Utility's application related to its procurement activities recorded in the ERRA for the period of January 1, 2003 through May 31, 2003, finding that the Utility's contract administration, least cost dispatch, procurement activities, and generation fuel costs were in compliance with its 2003 updated procurement plan. In July 2005, the CPUC approved the Utility application related to the remainder of the record period (i.e., June 1, 2003 to December 31, 2003) that found the Utility's contract administration, least cost dispatch, procurement activities, and generation fuel costs to be in compliance with its 2003 updated procurement plan. In February 2005, the Utility filed an ERRA compliance review application for the January 1, 2004 to December 31, 2004 record period. On July 1, 2005, the Office of Ratepayer Advocates, or ORA, issued its report on the Utility's ERRA compliance review for the January 1, 2004 to December 31, 2004 record period. In its report, the ORA found that the Utility's electric contract administration and least cost dispatch of resources were reasonable. However, the ORA recommends a disallowance of approximately \$2 million related to utility retained generation operations. Final action on the 2004 record period application is expected before the end of 2005. PG&E Corporation and the Utility are unable to predict whether an actual disallowance will result or the size of any potential disallowance. In addition, it is uncertain whether the CPUC will modify or eliminate the maximum disallowance for future years.

New Long-Term Generation Resource Commitments

In accordance with the Utility's CPUC-approved long-term electricity procurement plan, the Utility has requested offers from providers of all potential sources of new generation (e.g., conventional or renewable resources to be provided under utility-owned projects or turnkey developments, or under third-party power purchase agreements) for approximately 1,200 MW of peaking resources by 2008 and an additional 1,000 MW of load-following resources by 2010.

Initial offers were submitted to the Utility in late April 2005. The Utility has selected participants to provide additional information through second round offers. The Utility anticipates submitting executed contracts to the CPUC for approval in the fourth quarter of 2005.

Renewable Energy Contracts

The California Renewables Portfolio Standard, or RPS, requires California utilities to increase its purchases of renewable energy (such as biomass, wind, solar and geothermal energy) by at least 1% of its retail sales per year beginning in 2003, referred to as the RPS target, so that the amount of electricity purchased from renewable resources equals at least 20% of its total retail sales by the end of 2017. The CPUC intends that the 20% goal be met by 2010. The CPUC has also stated that compliance with the 20% goal must be met through actual deliveries of power, although it has adopted flexible compliance rules that allow the Utility to meet a portion of its RPS target through the execution of contracts for future delivery of power. Unless waived by the CPUC, and subject to the CPUC's flexible compliance rules, the penalty for failing to procure at least 75% of the annual RPS target is 5 cents per each kWh of the shortfall, subject to an overall annual penalty maximum of \$25 million per utility.

In July 2005, the CPUC approved the Utility's execution of three new renewable power purchase contracts that will help the Utility meet its end of year 2005 RPS target. In addition, the CPUC approved the 2005 RPS solicitation for bids from renewable energy providers, which the Utility expects to issue on August 4, 2005. As a result of this solicitation, the Utility may enter into additional contracts for future deliveries that would fully satisfy its end of year 2005 RPS target.

DWR Allocated Contracts

The Utility acts as a billing agent for the collection of the DWR's revenue requirements from the Utility's customers. The DWR's revenue requirements consist of a power charge to pay for the DWR's costs of purchasing electricity under its contracts and a bond charge to pay for the DWR's costs associated with its \$11.3 billion bond offering completed in November 2002. In December 2004, the CPUC issued a decision on the permanent cost allocation methodology for the DWR's power charge revenue requirements in 2004 and subsequent years, among the three California investor-owned electric utilities. In January 2005, the CPUC granted limited rehearing of its permanent cost allocation decision to address how to calculate the above-market costs of the DWR power contracts. In June 2005, the CPUC adopted a decision which modifies the permanent cost allocation methodology used to allocate DWR's costs of purchasing electricity among the three California investor-owned electric utilities. As a result, the Utility anticipates its DWR annual revenue requirement will increase in 2006. However, since the DWR revenue requirement is a pass-through to the Utility customers, any adjustments thereto should not affect the Utility's results of operations.

Diablo Canyon Steam Generator Replacement Projects

On February 24, 2005 the CPUC issued an interim decision on the Utility's Diablo Canyon Steam Generator Replacement Project, or SGRP, application. The interim decision concluded that the SGRP is cost-effective and \$706 million, as adjusted for actual inflation and cost of capital, is a reasonable estimate of the SGRP cost. The interim decision also concluded that an after-the-fact reasonableness review of the SGRP cost is not required, but not precluded either. It adopts a maximum allowable SGRP cost cap of \$815 million as adjusted for actual inflation and cost of capital, and the Utility will not be allowed to recover SGRP costs in excess of this amount. The Utility will file an advice letter to request authority to implement a rate increase, subject to refund, for each unit at the time each unit begins commercial operations. After installation is complete, and both units are operational, the Utility will be required to file an application to include the costs permanently in rates. The interim decision does not approve or disapprove the SGRP, guarantee or approve the recovery of any expenditures related thereto, or dictate the outcome of the environmental review of the SGRP pursuant to the California Environmental Quality Act, or CEQA. A final decision, which will include the results of the CEQA review, is expected in September 2005. As of June 30, 2005, expenditures on the project of approximately \$35.7 million have been incurred. These expenditures are expected to increase to approximately \$59 million by September 2005 when the CPUC's final decision approving the project is expected. If the CPUC approves the project, the Utility estimates it would spend an additional \$20.3 million in the last quarter of 2005. If the CPUC does not approve the projects, then the Utility will terminate the contracts and seek to recover the project costs that it incurred before termination from customers through the abandoned project process.

Annual Earnings Assessment Proceeding for Energy Efficiency Program Activities and Public Purpose Programs

On April 4, 2005, the Utility filed a motion with the CPUC seeking approval of a settlement agreement entered into on April 4, 2005 between the Utility and the CPUC's ORA. The settlement agreement proposes the resolution of the Utility's claims that have been pending for several years for shareholder incentives earned by the Utility for the successful implementation of demand-side management, energy efficiency, and low-income energy efficiency programs for past program years 1994 through 2001. The Utility's claims for shareholder incentives are addressed in the Utility's Annual Earnings Assessment Proceeding, or AEAP. In addition to resolving claims made in the pending AEAPs, the settlement agreement proposes to resolve all future claims for shareholder incentives relating to past program years that the Utility would otherwise have made in future AEAPs through 2010.

The Utility's total current and future shareholder incentive claims aggregate to approximately \$207 million. Under the settlement agreement, the parties have agreed that the results to date show that the energy savings anticipated in the Utility's shareholder incentive claims are being realized. The parties have proposed that the Utility receive shareholder incentives of approximately \$186 million to resolve the Utility's claims in the pending and future AEAPs. The parties have proposed that approximately \$160 million be collected from electric customers and approximately \$26 million be collected from gas customers, in proportion to the relative allocations of the original claims. The Utility has already collected \$28 million of the \$160 million from electric customers.

PG&E Corporation and the Utility cannot predict whether or when the CPUC will approve the settlement agreement. Assuming the CPUC approves the settlement agreement, the Utility would record pre-tax income of approximately \$186 million during the quarter in which the settlement agreement is approved by the CPUC.

Pending CPUC Investigations

On March 17, 2005, the CPUC issued an order that institutes an investigation into the circumstances surrounding a fire that occurred at the Utility's Mission Street substation in San Francisco in December 2003 and the ensuing power outage. Approximately 100,000 of the Utility's customers were affected by the outage, which began in the early evening of December 20, 2003. While most customers had their power restored by the next morning, the outage lasted more than 24 hours for some customers. Noting that the Utility had failed to implement its own recommendations made following an investigation of a 1996 fire at the same substation, the CPUC's order found that good cause exists to consider the safety and reliability of the Utility's other indoor substations. The order also noted that the CPUC has authority to impose penalties in the amount of \$500 to \$20,000 per day per offense for violations of the Public Utilities Code. The order states that the CPUC may consider a penalty for each customer that lost power or for each day the outage was ongoing.

In addition, the CPUC issued a press release noting that CPUC staff also would investigate the causes of a fire and power outage that originated at the Mission Street substation on March 26, 2005, that affected approximately 23,500 of the Utility's customers. It is presently unknown whether the CPUC will open a separate investigation, or whether the CPUC will address the 2005 fire as part of the current investigation. The CPUC's Consumer Protection and Safety Division, or CPSD, and the City and County of San Francisco have filed testimony in the current investigation criticizing the Utility's response to the March 2005 fire. The Utility, however, believes the March 2005 incident demonstrated the effectiveness of the changes made in its practices and facilities following the December 2003 incident.

The CPSD has recommended that the Utility pay a penalty of approximately \$10 million, based on a per-day penalty of \$3,225 multiplied by approximately 3,100 days since 1996 when the earlier fire and outage occurred at the Mission Street substation. The City and County of San Francisco has recommended that the Utility pay a penalty of approximately \$14 million. The Utility will file a response to the recommendations by August 19, 2005. A final decision on the investigation is expected during the first quarter of 2006. PG&E Corporation and the Utility believe that the ultimate outcome of this matter will not have a material adverse effect on PG&E Corporation's or the Utility's financial condition or results of operations.

The CPUC also is conducting an investigation into the Utility's billing and collection practices that has been opened at the request of The Utility Reform Network, or TURN. On July 15, 2005, the Utility and the CPSD filed a joint motion for an extension of the schedule in this investigation requesting the CPUC approve a schedule that would require CPSD's report to be due on December 16, 2005, the Utility's response to be due on February 17, 2006, and rebuttal testimony to be due on March 31, 2006, with hearings to begin on April 17, 2006.

If the CPUC finds that the Utility violated applicable tariffs or the CPUC's orders or rules, the CPUC may impose penalties on the Utility or order the Utility to refund any amounts collected in violation of tariffs, plus interest, to customers who paid such amounts. PG&E Corporation and the Utility continue to believe that the ultimate outcome of this matter will not have a material adverse effect on PG&E Corporation's or the Utility's financial condition or results of operations.

2007 GRC

On August 1, 2005, the Utility tendered its Notice of Intent, or NOI, to file its 2007 GRC application. In the 2007 GRC, the CPUC will determine the amount of authorized base revenues to be collected from customers to recover the Utility's basic business and operational costs for its gas and electric distribution and electric generation operations for the period 2007 through 2009. These revenue requirements are determined based on a forecast of costs for 2007 (the "test year"). The NOI indicates that the Utility's GRC application will request an increase in electric and gas distribution revenue requirements of \$393 million and \$61 million, respectively, over the projected authorized 2006 revenue requirements to maintain current service levels to support increased investment in distribution infrastructure as plant in service is upgraded and replaced, and to adjust for wages and inflation. The NOI also indicates the Utility will request an increase of \$48 million, over the projected authorized 2006 revenue requirement, to cover increases in operational costs for the Utility's fossil, hydro, and nuclear generation facilities and administrative costs associated with electric procurement activities. (The projected 2006 revenue requirements assume the minimum increase over 2003 revenues approved by the CPUC in the Utility's 2003 GRC). The NOI indicated that the Utility's preliminary forecast of average annual distribution and generation capital expenditures over the 2007-2009 period would be approximately \$1.5 billion, slightly higher than the \$1.3 billion previously forecast.

The Utility also has indicated that it will seek an increase of \$167 million for 2008 and \$242 million for 2009 designed to avoid a reduction in earnings in years between GRCs that would otherwise occur because of increases in rate base and expenses.

The NOI proposes that the Utility's 2008 and 2009 total gas and electric revenue requirements be reduced by \$41 million in 2008 and

\$97 million in 2009 to capture an estimate of net savings that the Utility anticipates may be realized from the operating and cost efficiencies achieved through implementation of specific initiatives identified by the Utility to provide better, faster and more cost-effective service to its customers. In addition, due to uncertainty about savings to be realized from these initiatives, the Utility will propose a sharing mechanism by which shareholders and customers would share equally in any earnings that would exceed an actual ROE equal to the then-authorized ROE plus 50 basis points, with the customers receiving 100% of the earnings that would exceed an actual ROE equal to the then-authorized ROE plus 3.00%. If the Utility's actual ROE would be less than an amount equal to the then-authorized ROE minus 50 basis points, shareholders and customers would share the shortfall equally. For example, based on the Utility's currently authorized ROE of 11.22%, shareholders and customers would share equally in any earnings that would exceed an 11.72% ROE and customers would receive 100% of the earnings that would exceed a 14.22% ROE. If the Utility's ROE would be less than 10.72%, shareholders and customers would share the shortfall (i.e., the difference between 10.72% and the ROE used to determine the shortfall) equally.

After addressing any deficiencies that may be identified and after acceptance for filing by the Executive Director of the CPUC, the Utility must wait 60 days to file the actual GRC application with the CPUC. Hearings will then be held and a decision issued setting the 2007 revenue requirement and addressing other issues. A final decision is expected from the CPUC by the end of 2006.

PG&E Corporation and the Utility are unable to predict what amount of revenue requirements the CPUC will authorize for the 2007 through 2009 period, when a final decision in this proceeding will be received, or the impact it will have on their financial condition or results of operations.

FERC Transmission Rate Case

On August 1, 2005, the Utility filed an application with the FERC requesting authority to recover approximately \$655 million in electric transmission retail rates annually, effective October 1, 2005. The proposed rates represent an increase of approximately \$110 million over current rates. The requested increase is mainly attributable to significant capital additions and replacements made to the Utility's system to accommodate load growth, maintain infrastructure, and ensure safe and reliable service. In addition, the request includes a return on equity of 12.00%. PG&E Corporation and the Utility are unable to predict what amount of revenue requirements and the effective date the FERC will authorize, when a final decision will be received from the FERC, or the impact it will have on the results of operations.

Defined Benefit Pension Plan Contributions

On July 13, 2005, the Utility filed a petition requesting the CPUC to authorize it to resume contributions to its employee pension trust beginning in 2006 based on the funded status of the pension fund. If the CPUC grants the petition, the Utility will file an application before December 2005 requesting approval of the revenue requirement increase necessary to fund the contributions, separate from the 2007 GRC application to be filed in early December 2005. The petition estimates the annual revenue requirement associated with the pension contributions for its generation and distribution businesses to be approximately \$185 million, and it requests that the amount be recovered in rates beginning January 1, 2006, subject to refund to customers if the CPUC later disapproves the contributions. Should the CPUC not grant the petition, the Utility will include the pension request in its 2007 GRC application. In the Utility's last GRC decision in 2004, the CPUC denied the Utility's request to resume pension contributions based on a finding that the pension plan's funded status was in excess of 100%. The Utility is also asking FERC in its transmission owner rate case filing discussed above to allow approximately \$14 million annual revenue requirement associated with the pension contributions for its electric transmission business to be recovered in rates beginning March 1, 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 transportation and storage, other goods and services, and other aspects of their business. PG&E Corporation and the Utility categorize market risks as price risk, interest rate risk and credit risk. The Utility actively manages market risks through risk management programs that are designed to support business objectives, reduce costs, discourage unauthorized risk-taking, reduce earnings volatility and manage cash flows. The Utility uses derivative instruments only for non-trading purposes (i.e., risk mitigation) and not for speculative purposes. The Utility's risk management activities include the use of energy and financial instruments, including forward contracts, futures, swaps, options, and other instruments and agreements, most of which are accounted for as derivative instruments. Some contracts are accounted for as leases.

The Utility estimates fair value of derivative instruments using the midpoint of quoted bid and asked forward prices, including quotes from customers, brokers, electronic exchanges and public indices, supplemented by online price information from news services. When market data is not available, the Utility uses models to estimate fair value.

Price Risk

Convertible Subordinated Notes

PG&E Corporation currently has outstanding \$280 million of 9.50% Convertible Subordinated Notes that are scheduled to mature on June 30, 2010. These Convertible Subordinated Notes may be converted (at the option of the holder) at any time prior to maturity into 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 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 at the same payout as common stockholders with the number of shares determined by dividing the principal amount of the Convertible Subordinated Notes by the conversion price. On each of April 15 and July 15, 2005, PG&E Corporation paid approximately \$6 million of "pass-through dividends" to holders of the 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 "pass-through dividends," if any).

In accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," or 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 marked to market on PG&E Corporation's Consolidated Statements of Income as a non-operating expense (in Other expense, net), and reflected at fair value on PG&E Corporation's Consolidated Balance Sheet at June 30, 2005. At June 30, 2005, the total estimated fair value of the dividend participation rights component, on a pre-tax basis, was approximately \$91 million of which \$20 million is classified as a current liability (in Current liabilities-Other) and \$71 million is classified as a noncurrent liability (in Noncurrent liabilities-Other). The change in the liability for the quarter ended June 30, 2005, was immaterial. The mark to market change was approximately \$33 million, pre-tax, for the quarter ended June 30, 2004.

Electricity

The Utility relies on electricity from a diverse mix of resources, including third-party contracts, amounts allocated under DWR contracts and its own electricity generation facilities. In addition, the Utility purchases and sells electricity on the spot market and the short-term forward market (contracts with delivery times ranging from one hour ahead to one year ahead).

It is estimated that the residual net open position (the amount of energy needed to meet the demands of customers, plus applicable capacity or reserve margins, that is not satisfied from the Utility's own generation facilities, purchase contracts or DWR contracts allocated to the Utility's customers) will change over time for a number of reasons, including:

- Periodic expirations of existing energy and capacity purchase contracts, or entering into new energy and capacity purchase contracts;
- Fluctuation in the output of hydroelectric and other renewable power facilities owned or under contract;
- Changes in the Utility's customers' electricity demands due to customer and economic growth and weather, and implementation of new energy efficiency and demand response programs, community choice aggregation, and a core/noncore retail market structure;
- Changes to planning reserve and operating requirements, and what is eligible to meet these requirements;
- The reallocation of the DWR power purchase contracts among California investor-owned electric utilities; and
- The acquisition, retirement or closure of Utility generation facilities.

In addition, lengthy, unexpected outages of the Utility's generation or contracted facilities, or a failure to perform by any of the counterparties to electricity purchase contracts or the DWR allocated contracts, would immediately increase the Utility's residual net open position. The Utility expects to satisfy at least some of the residual net open position through new contracts. In December 2004, the CPUC approved, with certain modifications, the Utility's long-term electricity procurement plan, or LTPP, for the 2005 through 2014 period. The LTPP is detailed in the "Regulatory Matters" section of the MD&A in PG&E Corporation's and the Utility's combined 2004 Annual Report.

The Settlement Agreement provides that the Utility will recover its reasonable costs of providing utility service, including power procurement costs. In addition, California law requires that the CPUC review revenues and expenses associated with a CPUC-approved procurement plan at least semi-annually through 2006 and adjust retail electricity rates, or order refunds when there is an under or over-collection exceeding 5% of the Utility's prior year electricity procurement revenues, excluding the revenue collected on behalf of the DWR. In addition, the CPUC has established a maximum procurement disallowance of approximately \$36 million for the Utility's administration of the DWR contracts and least-cost dispatch. Adverse market price changes are not expected to impact the Utility's net income while these cost recovery regulatory mechanisms remain in place. However, the Utility is at risk to the extent that the CPUC may in the future disallow portions or the full costs of transactions. Additionally, market price changes could impact the timing of the Utility's cash flows.

Nuclear Fuel

The Utility purchases nuclear fuel for Diablo Canyon through contracts with terms ranging from two to five years. These long-term nuclear fuel agreements are with large, well-established international producers in order to diversify its commitments and provide security of

supply.

Some nuclear fuel purchases are subject to tariffs of up to 8% on imports from certain countries. In the past, the Utility's long-term nuclear fuel contracts were not subject to these tariffs. However, these contracts expired at the end of 2004, and prices under existing and future contracts may be higher as a result of such tariffs. In addition, because of an increase in U.S. demand for uranium compared with the domestic supply, uranium prices are trending higher in 2005. During the quarter ended June 30, 2005, the Utility did not enter into any nuclear fuel purchase agreements.

As the Utility replaces contracts that expired at the end of 2004 with new higher priced uranium contracts, nuclear fuel costs will rise. These costs are recovered in ERRA (see the "Electricity Generation Resources" section of this MD&A), therefore, the changes in nuclear fuel prices are not expected to materially impact net income.

Natural Gas

The Utility generally enters into physical and financial natural gas commodity contracts from one to thirty months in length to fulfill the needs of its retail core customers. Changes in temperature cause natural gas demand to vary daily, monthly and seasonally. Consequently, significant volumes of gas may be purchased in the monthly and, to a lesser extent, daily spot market. The Utility's cost of natural gas purchased for its core customers includes the commodity cost, the cost of Canadian and interstate transportation and gas storage costs.

Under the Core Procurement Incentive Mechanism, or CPIM, the Utility's purchase costs for a fixed 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. Costs that fall within a tolerance band, which is 99% to 102% of the benchmark, are considered reasonable and are fully recovered in customers' rates. One-half of the costs above 102% of the benchmark are recoverable in customers' rates, and the Utility's customers receive, in their rates, three-fourths of any savings resulting from the Utility's cost of natural gas that is less than 99% of the benchmark. The shareholder award is capped at the lower of 1.5% of total natural gas commodity costs or \$25 million. While this cost recovery mechanism remains in place, changes in the price of natural gas are not expected to materially impact net income.

Transportation and Storage

The Utility currently faces price and volumetric risk for the portion of intrastate natural gas transportation capacity that is not contracted under fixed reservation charges used by core customers. Non-core customers contract with the Utility for natural gas transportation and storage, along with natural gas parking and lending (market center) services. The Utility is at risk for any natural gas transportation and storage revenue volatility. Transportation is sold at competitive market-based rates within a cost-of-service tariff framework. There are significant seasonal and annual variations in the demand for natural gas transportation and storage services. The Utility sells most of its pipeline capacity based on the volume of natural gas that is transported by its customers. As a result, the Utility's natural gas transportation revenues fluctuate.

The Utility uses value-at-risk to measure the Utility's exposure to market conditions that could impact transportation and storage revenues based on changes in market prices and demand for pipeline and storage services over a rolling 12-month holding period. 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 will be at least as large as the reported value-at-risk. The Utility's value-at-risk calculated under this methodology was approximately \$31 million at June 30, 2005. The Utility's high, low, and average value-at-risk during the three months ended June 30, 2005 were approximately \$39 million, \$31 million and \$35 million, respectively. Value-at-risk has several limitations as a measure of portfolio risk, including, but not limited to, inadequate indication of the exposure of a portfolio to extreme price movements and not capturing the intra-day risk related to position changes.

Beginning January 1, 2005, the Utility began calculating value-at-risk using the methodology described above on a prospective basis only. For comparative purposes in 2005, the Utility will continue to report value-at-risk for the transportation and storage portfolio under the methodology formerly used in addition to value-at-risk calculated under the enhanced methodology.

Prior to January 1, 2005, the Utility used value-at-risk to measure the expected maximum change over a one-day period in the rolling 18-month forward value of its transportation and storage portfolio. This calculation is based on a 95% confidence level, which means that there is a 5% probability that the portfolio will incur a loss in value in one day at least as large as the reported value-at-risk. For example, if the value-at-risk is calculated at \$5 million, there is a 95% probability that the value of the portfolio resulting from a one-day price movement would not decline by more than \$5 million. This value-at-risk methodology provides an indication of the Utility's exposure to potential market conditions that could impact revenues based on one-day price changes.

The Utility's daily value-at-risk for its transportation and storage portfolio calculated under the methodology used prior to January 1, 2005 was approximately \$2 million at June 30, 2005 and approximately \$3 million at June 30, 2004. A comparison of daily values-at-risk is included in order to provide context around the one-day amounts. The Utility's high, low and average transportation and storage value-at-risk during the six months ended June 30, 2005 were approximately \$4 million, \$1 million and \$2 million, respectively. The Utility's high, low and average transportation and storage value-at-risk during the six months ended June 30, 2004 were approximately \$6 million, \$2 million and \$4 million, respectively.

Value-at-risk calculated under the methodology used prior to January 1, 2005 has several limitations as a measure of portfolio risk, including, but not limited to, underestimation of the risk of a portfolio with significant options exposure, mismatch of one-day liquidation period assumed in the value-at-risk methodology as compared to the longer term holding period of the storage and transportation portfolio, and inadequate indication of the exposure of a portfolio to extreme price movements. In addition, this value-at-risk methodology does not measure intra-day risk from position changes nor does it measure volumetric uncertainty in the demand for pipeline services.

Due to the limitations of this value-at-risk methodology, the Utility enhanced the calculation methodology as described above to (1) capture uncertainty with respect to demand (volumetric uncertainty) for pipeline services, (2) reflect the market conditions in which the pipeline operates by increasing the holding period to 12 months, and (3) include the uncertainty associated with the option exposure in the pipeline portfolio.

Interest Rate Risk

Interest rate risk is the risk that changes in interest rates could adversely affect earnings or cash flows. Specific interest rate risks for PG&E Corporation and the Utility include the risk of increasing interest rates on variable rate obligations.

Interest rate risk sensitivity analysis is used to measure interest rate risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. At June 30, 2005, 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.

Credit Risk

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.

PG&E Corporation had gross accounts receivable of approximately \$2.1 billion at June 30, 2005 and approximately \$2.2 billion at December 31, 2004. The majority of the accounts receivable were associated with the Utility's residential and small commercial customers. Based upon historical experience and evaluation of then-current factors, allowances for doubtful accounts of approximately \$91 million at June 30, 2005 and approximately \$93 million at December 31, 2004 were recorded against those accounts receivable. In accordance with tariffs, credit risk exposure is limited by requiring deposits from new customers and from those customers whose past payment practices are below standard. The Utility has a regional concentration of credit risk associated with its receivables from residential and small commercial customers in northern and central California. However, material loss due to non-performance from these customers is not considered likely.

The Utility manages credit risk for its wholesale customers and 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.

Credit exposure for the Utility's wholesale customers and counterparties is calculated daily. If exposure exceeds the established limits, the Utility takes immediate action to reduce the exposure or obtain additional collateral, or both. Further, the Utility relies heavily 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 contractually specified limits.

The Utility calculates gross credit exposure for each of its wholesale customers and counterparties as the current mark-to-market value of the contract (*i.e.* , the amount that would be lost if the counterparty defaulted today), plus or minus any outstanding net receivables or payables, before the application of credit collateral. During the three months ended June 30, 2005, the Utility recognized no material losses due to contract defaults or bankruptcies. At June 30, 2005, there were two counterparties that represented greater than 10% of the Utility's net wholesale credit exposure. Both of these counterparties were investment grade, representing a total of approximately 44% of the Utility's net wholesale credit exposure.

The Utility conducts business with wholesale counterparties mainly in the energy industry, including other California investor-owned electric utilities, municipal utilities, energy trading companies, financial institutions, and oil and natural gas production companies located in the United States and Canada. 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. Credit losses experienced as a result of electrical and gas procurement activities are expected to be recoverable from customers and are therefore, not expected to have a material impact on earnings.

CRITICAL ACCOUNTING POLICIES

The preparation of Consolidated Financial Statements in accordance with GAAP involves the use of estimates and assumptions that affect the recorded amounts of assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The accounting policies described below are considered to be critical accounting policies, due, in part, to their complexity and because their application is relevant and material to the financial condition 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 outlined below.

Regulatory Assets and Liabilities

PG&E Corporation and the Utility account for the financial effects of regulation in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," as amended, or 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 except for the operations of a natural gas pipeline.

Under SFAS No. 71, regulatory assets represent capitalized costs that otherwise would be charged to expense under GAAP. These costs are later recovered through regulated rates. Regulatory liabilities are created by rate actions of a regulator that will later be credited to customers through the ratemaking process. Regulatory assets and liabilities are recorded when it is probable, as defined in SFAS No. 5, "Accounting for Contingencies," or SFAS No. 5, that these items will be recovered or reflected in future rates. Determining probability requires significant judgment on the part of management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, CPUC and FERC administrative law judge proposed decisions, final regulatory orders and the strength or status of applications for regulatory rehearings or state court appeals. The Utility also maintains regulatory balancing accounts, which are comprised of sales and cost balancing accounts. These balancing accounts are used to record the differences between revenues and costs that can be recovered through rates.

If the Utility determined that it could not apply SFAS No. 71 to its operations or, if under SFAS No. 71 it could not conclude that it is probable that revenues or costs would be recovered or reflected in future rates, the revenues or costs would be charged to income in the period in which they were incurred. If it is determined that a regulatory asset is no longer probable of recovery in rates, then SFAS No. 71 requires that it be written off at that time. At June 30, 2005, PG&E Corporation and the Utility reported regulatory assets (including current regulatory balancing accounts receivable) of approximately \$7.1 billion and regulatory liabilities (including current balancing accounts payable) of approximately \$4.9 billion.

Unbilled Revenues

The Utility records revenue as electricity and natural gas are delivered. A portion of the revenue recognized has not yet been billed. Unbilled revenues are determined by factoring an estimate of the electricity and natural gas load delivered with recent historical usage and rate patterns. At June 30, 2005, the Utility had recorded approximately \$550 million in unbilled revenues.

Environmental Remediation Liabilities

Given the complexities of the legal and regulatory environment regarding environmental laws, the process of estimating environmental remediation liabilities is a subjective one. The Utility records a liability associated with environmental remediation activities when it is determined that remediation is probable, as defined in SFAS No. 5, and the cost can be estimated in a reasonable manner. The liability can be based on many factors, including site investigations, remediation, operations, maintenance, monitoring and closure. This liability is recorded at the lower range of estimated costs, unless a more objective estimate can be achieved. The recorded liability is re-examined every quarter.

At June 30, 2005, the Utility's accrual for undiscounted environmental liability was approximately \$410 million. The Utility's undiscounted future costs could increase to as much as \$578 million if other potentially responsible parties are not able to contribute to the settlement of these costs or the extent of contamination or necessary remediation is greater than anticipated.

Asset Retirement Obligations

The Utility accounts for its nuclear generation and certain fossil generation facilities under SFAS No. 143, "Accounting for Asset Retirement Obligations," or SFAS No. 143. SFAS No. 143 requires that an asset retirement obligation be recorded at fair value in the period in which it is incurred if a reasonable estimate of fair value can be made. In the same period, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. Rate-regulated entities may recognize regulatory assets or liabilities as a result of timing differences between the recognition of costs as recorded in accordance with SFAS No. 143 and costs recovered through the ratemaking process.

There are uncertainties regarding the ultimate cost associated with retiring the assets the Utility has accounted for in accordance with SFAS No. 143. These include, but are not limited to changes in assumed dates of decommissioning, regulatory requirements, technology, cost of labor, materials, and equipment. At June 30, 2005, the Utility's estimated cost of retiring these assets was approximately \$1.3 billion.

Pension and Other Postretirement Plans

Certain employees and retirees of PG&E Corporation and its subsidiaries participate in qualified and non-qualified non-contributory defined benefit pension plans. Certain retired employees and their eligible dependents of PG&E Corporation and its subsidiaries also participate in contributory medical plans, and certain retired employees participate in life insurance plans (referred to collectively as other benefits). Amounts that PG&E Corporation and the Utility recognize as costs and obligations to provide pension benefits under SFAS No. 87, "Employers' Accounting for Pensions," and other benefits under SFAS No. 106, "Employers Accounting for Postretirement Benefits other than Pensions," are based on a variety of factors. These factors include the provisions of the plans, employee demographics and various actuarial

calculations, assumptions and accounting mechanisms. Because of the complexity of these calculations, the long-term nature of these obligations and the importance of the assumptions utilized, PG&E Corporation's and the Utility's estimate of these costs and obligations is a critical accounting estimate.

In accordance with accounting rules, changes in benefit obligations associated with these assumptions may not be recognized as costs on the income statement. Differences between actuarial assumptions and actual plan results are deferred and are amortized into cost only when the accumulated differences exceed 10% of the greater of the projected benefit obligation or the market-value of the related plan assets. If necessary, the excess is amortized over the average remaining service period of active employees. As such, significant portions of benefit costs recorded in any period may not reflect the actual level of cash benefits provided to plan participants. Under SFAS No. 71, regulatory adjustments have been recorded in the Consolidated Statements of Income and 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, 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 contributions on a tax-deductible basis to the appropriate trusts.

ACCOUNTING PRONOUNCEMENTS ISSUED BUT NOT YET ADOPTED

Refer to Note 1 in 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 its respective consolidated 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 effects on the environment.

In the normal course of business, PG&E Corporation and the Utility are named as parties in a number of claims and lawsuits. See Note 7 of the Notes to the Condensed Consolidated Financial Statements for further discussion. As previously disclosed, the Utility has recorded a \$160 million reserve in its financial statements with respect to the chromium litigation described in Note 7. Given recent rulings and appellate writs regarding the Utility's motions, and the California Supreme Court's current review of similar issues in unrelated litigation, PG&E Corporation and the Utility are unable to predict whether the ultimate outcome of this matter, after taking into account the amount already reserved at June 30, 2005, would have a material adverse impact on PG&E Corporation's or the Utility's financial condition or results of operations.

ITEM 3: QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PG&E Corporation's and Pacific Gas and Electric Company's, or 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 Pacific Gas and Electric Company's, or the Utility's, disclosure controls and procedures as of June 30, 2005, 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 is recorded, processed, summarized, and reported within the time periods specified in the Securities and Exchange Commission rules and forms.

As of January 1, 2004, PG&E Corporation and the Utility adopted 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 low-income housing partnerships that were determined to be variable interest entities, or VIEs, under FIN 46R. PG&E Corporation and the Utility do not have the legal right or authority to assess the internal controls of VIEs. Therefore, PG&E Corporation's and the Utility's evaluation of disclosure controls and procedures performed as of June 30, 2005 did not include these entities in that evaluation. PG&E Corporation and the Utility have not designed, established, or maintained disclosure controls and procedures for consolidated VIEs.

There were no changes in internal controls over financial reporting that occurred during the quarter ended June 30, 2005, 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

For additional information regarding certain of the legal proceedings presented below, see Note 7 of the Notes to the Condensed Consolidated Financial Statements.

Pacific Gas and Electric Company Chapter 11 Filing

On June 13, 2005, the California Court of Appeal summarily denied the petitions for review of the California Public Utilities Commission's, or the CPUC's, order approving the Settlement Agreement and order denying rehearing of its approval order that had been filed by the City and County of San Francisco, or CCSF, and Aglet Consumer Alliance, or Aglet. CCSF and Aglet have not appealed the appellate court's denial of their petitions and the time period within which an appeal could be filed has elapsed.

In addition, two former CPUC commissioners who did not vote to approve the Settlement Agreement filed an appeal of the bankruptcy court's confirmation order with the U.S. District Court for the Northern District of California, or the District Court. On July 15, 2004, the District Court dismissed their appeal. The former commissioners have appealed the District Court's order with the U.S. Court of Appeals for the Ninth Circuit, or Ninth Circuit. Briefing is complete, and the Ninth Circuit is likely to schedule oral arguments on the appeal by the end of the year. On April 12, 2005, the District Court entered an order dismissing a second appeal of the confirmation order that had been filed by the City of Palo Alto, but which the City of Palo Alto subsequently had agreed to dismiss voluntarily.

PG&E Corporation and Pacific Gas and Electric Company, or the Utility, believe the former commissioners' appeal of the confirmation order is without merit and will be rejected. If the bankruptcy court's confirmation order or the Settlement Agreement is overturned or modified on appeal, PG&E Corporation's and the Utility's financial condition and results of operations, and the Utility's ability to pay dividends or otherwise make distributions to PG&E Corporation, could be materially adversely affected.

The Utility's Chapter 11 proceeding has been previously disclosed in PG&E Corporation's and the Utility's combined 2004 Annual Report on Form 10-K in "Part I, Item 3: Legal Proceedings" and in PG&E Corporation's and the Utility's combined Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 in "Part II, Item 1: Legal Proceedings." For additional information, see Note 2 of the Notes to the Condensed Consolidated Financial Statements.

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

For information regarding this matter, see "Part I, Item 3: Legal Proceedings" in PG&E Corporation's and the Utility's combined 2004 Annual Report on Form 10-K.

In re: Natural Gas Royalties Qui Tam Litigation

For information regarding this matter, see "Part I, Item 3: Legal Proceedings" in PG&E Corporation's and the Utility's combined 2004 Annual Report on Form 10-K.

Diablo Canyon Power Plant

For information regarding matters relating to the Diablo Canyon Power Plant, see PG&E Corporation's and the Utility's combined 2004 Annual Report on Form 10-K.

Compressor Station Chromium Litigation

The Utility has filed 14 motions in the Superior Court for the County of Los Angeles, or Superior Court, challenging the test trial plaintiffs' lack of admissible scientific evidence that chromium caused the alleged injuries. In February 2005, the Superior Court denied two of these motions. The Utility filed motions for reconsideration of these orders with the Superior Court and also filed a request with the appellate court seeking to overturn or modify the orders because they are inconsistent with recent California appellate decisions concerning the admissibility of expert testimony and the requirements for proving medical causation. After these motions for reconsideration and the request were filed, the California Supreme Court granted review of one of these recent appellate decisions. In April 2005, the Superior Court heard arguments on both motions for reconsideration and denied the motions in July 2005.

On June 9, 2005, the Superior Court denied another of the Utility's motions to exclude evidence, and the Utility filed a motion for reconsideration. On July 18, 2005, the Superior Court denied this motion for reconsideration. The Superior Court denied another of the Utility's motions to exclude evidence on June 29, 2005.

As previously disclosed, the Utility has recorded a \$160 million reserve in its financial statements with respect to the chromium litigation. Given recent rulings and appellate writs regarding the Utility's motions, and the California Supreme Court's current review of similar issues in unrelated litigation, PG&E Corporation and the Utility are no longer able to predict whether the ultimate outcome of this matter, after taking into account the amount already reserved at June 30, 2005, would have a material adverse impact on PG&E Corporation's or the Utility's financial condition or results of operations.

For more information regarding the chromium litigation, see "Part I, Item 3: Legal Proceedings" in PG&E Corporation's and the Utility's combined 2004 Annual Report on Form 10-K, "Part II, Item 1: Legal Proceedings" in PG&E Corporation's and the Utility's combined Quarterly Report on Form 10-Q for the quarter ended March 31, 2005, and Note 7 to the Notes to the Condensed Consolidated Financial Statements.

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

On May 17, 2005, the plaintiffs filed a petition with the California Court of Appeal seeking an order requiring the San Francisco Superior Court, or Superior Court, to vacate its March 2005 decision finding that the standard for calculating the number of alleged violations of Section 17200 in this case is a "per act" test (not the "per victim" and "per [customer] bill" standards advocated by the plaintiffs). Plaintiffs argued that, by selecting the "per act" test to determine the number of violations, the Superior Court decided disputed factual questions and improperly exceeded the scope of the legal issue defined for the bifurcated trial. PG&E Corporation filed a response on June 9, 2005, pointing out that the Superior Court's March 2005 decision resolved only the legal question of what standard should be applied in determining the number of Section 17200 violations, that the issues raised by the plaintiffs are not yet ripe for decision, and that the March 2005 ruling does not preclude discovery, as plaintiffs claim. On July 27, 2005, the California Court of Appeal summarily denied plaintiffs' petition.

As previously ordered by the Superior Court, in June 2005, the plaintiffs provided a definitive list of transactions they claim violate Section 17200. In order to add to this list later, plaintiffs will be required to show good cause. At a case management conference on July 20, 2005, the Superior Court directed plaintiffs to update their transactions list by explaining why the transactions were allegedly unlawful under Section 17200. The next case management conference is scheduled for September 22, 2005.

For more information regarding these cases, see "Part I, Item 3: Legal Proceedings" of PG&E Corporation's and the Utility's combined 2004 Annual Report on Form 10-K and "Part II, Item 1: Legal Proceedings" of PG&E Corporation's and the Utility's combined Quarterly Report on Form 10-Q for the quarter ended March 31, 2005.

ITEM 2. CHANGES IN SECURITIES, USE OF PROCEEDS AND ISSUER PURCHASES OF EQUITY SECURITIES

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 June 30, 2005, warrant holders exercised, on a net exercise basis, warrants to purchase 125,673 shares, and received 125,635 shares of PG&E Corporation common stock. As of June 30, 2005, warrant holders had exercised, on a net exercise basis, warrants to purchase 4,922,549 shares, and had received 4,920,758 shares of PG&E Corporation common stock since the warrants were issued.

Pacific Gas and Electric Company, or the Utility, did not make any sales of unregistered equity securities during the quarter ended June 30, 2005, the period covered by this report.

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased		Average Price Paid Per Share		Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs ⁽²⁾⁽³⁾		Approximate Dollar Value of Shares that may yet be Purchased Under the Plans or Programs	
	Preferred Stock	Common Stock	Preferred Stock	Common Stock	Preferred Stock	Common Stock	Preferred Stock	Common Stock
April 1 through April 30, 2005	-	-	\$ -	\$ -	-	-	\$ -	-
May 1 through May 31, 2005	4,800,000 ⁽¹⁾	-	\$ 25.13424	\$ -	-	-	\$ -	-
June 1 through June 30, 2005	-	-	-	-	-	-	-	-

Total	4,800,000	-	\$	25.13424	\$	-	-	-	\$	-	\$	-
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- (1) On May 31, 2005, the Utility redeemed all outstanding shares of the Utility's 6.57% Redeemable First Preferred Stock and 6.30% Redeemable First Preferred Stock totaling approximately \$120 million aggregate par value. In addition to the \$25 per share redemption price, holders of the 6.57% Redeemable First Preferred Stock and the 6.30% Redeemable First Preferred Stock received an amount equal to all accumulated and unpaid dividends on such shares to and including May 31, 2005.
- (2) On September 15, 2004, the PG&E Corporation Board of Directors authorized the Corporation and its subsidiaries to repurchase shares of PG&E Corporation's common stock with an aggregate purchase price not to exceed PG&E Corporation's net cash proceeds from sales of PG&E Corporation's common stock upon exercise of options granted under PG&E Corporation's Stock Option Plan. The program was publicly announced in a Form 8-K filed by PG&E Corporation on October 14, 2004. Repurchases may be made from time to time until the program expires on December 31, 2005. Amounts remaining under this program are not determinable as PG&E Corporation cannot predict how many options will be exercised before December 31, 2005.
- (3) As previously reported, on December 15, 2004, PG&E Corporation's Board of Directors authorized the repurchase of up to \$975 million of its outstanding common stock. The program was publicly announced in a Form 8-K filed by PG&E Corporation on December 16, 2004. On February 16, 2005, the Board of Directors of PG&E Corporation increased the repurchase authorization to \$1.05 billion with such repurchases to be effected from time to time, but no later than June 30, 2006. As disclosed in a Form 8-K filed on March 4, 2005, PG&E Corporation entered into accelerated share repurchase arrangements with a broker on March 4, 2005, under which PG&E Corporation repurchased 29,489,400 shares for an aggregate purchase price of approximately \$1.05 billion. On June 16, 2005, PG&E Corporation entered into a new share forward agreement with the broker based on 11,430,000 shares to complete the balance of the March 4, 2005 arrangement. For further information, see the "Liquidity and Financial Resources" section included in Part I, Item 2: Management's Discussion and Analysis of Financial Condition and Results of Operations.

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

On April 20, 2005, PG&E Corporation and Pacific Gas and Electric Company held their joint annual meeting of shareholders. Information regarding the voting results of the meetings is contained in PG&E Corporation and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005, Part II, Item 4.

ITEM 5. OTHER INFORMATION

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

Pacific Gas and Electric Company, or the Utility's, earnings to fixed charges ratio for the three months ended June 30, 2005, was 4.35. The Utility's earnings to combined fixed charges and preferred stock dividends ratio for the three months ended June 30, 2005, was 4.10. 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

- 3.1 Bylaws of Pacific Gas and Electric Company amended as of June 15, 2005
- 10.1 Master Confirmation dated March 4, 2005, for accelerated share repurchase arrangements between PG&E Corporation and Goldman, Sachs & Co., as amended and supplemented by a Supplemental Confirmation dated June 16, 2005
- 10.2* Supplemental Executive Retirement Plan of PG&E Corporation, as amended effective as of June 15, 2005
- 11 Computation of Earnings Per Common Share
- 12.1 Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company
- 12.2 Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company
- 31.1 Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002
- 31.2 Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002

- 32.1** Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002
- 32.2** Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002

* Management contract or compensatory agreement

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

SIGNATURES

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

PG&E CORPORATION

CHRISTOPHER P. JOHNS

Christopher P. Johns
Senior Vice President and Controller
(duly authorized officer and principal accounting officer)

PACIFIC GAS AND ELECTRIC COMPANY

DINYAR B. MISTRY

Dinyar B. Mistry
Vice President and Controller
(duly authorized officer and principal accounting officer)

Dated: August 3, 2005

EXHIBIT INDEX

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

Bylaws
of
Pacific Gas and Electric Company
amended as of June 15, 2005

Article I.

SHAREHOLDERS.

1. **Place of Meeting.** All meetings of the shareholders shall be held at the office of the Corporation in the City and County of San Francisco, State of California, or at such other place, within or without the State of California, as may be designated by the Board of Directors.

2. **Annual Meetings.** The annual meeting of shareholders shall be held each year on a date and at a time designated by the Board of Directors.

Written notice of the annual meeting shall be given not less than ten (or, if sent by third-class mail, thirty) nor more than sixty days prior to the date of the meeting to each shareholder entitled to vote thereat. The notice shall state the place, day, and hour of such meeting, and those matters which the Board, at the time of mailing, intends to present for action by the shareholders.

Notice of any meeting of the shareholders shall be given by mail or telegraphic or other written communication, postage prepaid, to each holder of record of the stock entitled to vote thereat, at his address, as it appears on the books of the Corporation.

At an annual meeting of shareholders, only such business shall be conducted as shall have been properly brought before the annual meeting. To be properly brought before an annual meeting, business must be (i) specified in the notice of the annual meeting (or any supplement thereto) given by or at the direction of the Board, or (ii) otherwise properly brought before the annual meeting by a shareholder. For business to be properly brought before an annual meeting by a shareholder, including the nomination of any person (other than a person nominated by or at the direction of the Board) for election to the Board, the shareholder must have given timely and proper written notice to the Corporate Secretary of the Corporation. To be timely, the shareholder's written notice must be received at the principal executive office of the Corporation not less than forty-five days before the date corresponding to the mailing date of the notice and proxy materials for the prior year's annual meeting of shareholders; provided, however, that if the annual meeting to which the shareholder's written notice relates is to be held on a date that differs by more than thirty days from the date of the last annual meeting of shareholders, the shareholder's written notice to be timely must be so received not later than the close of business on the tenth day following the date on which public disclosure of the date of the annual meeting is made or given to shareholders. Any shareholder's written notice that is delivered after the close of business (5:00 p.m. local time) will be considered received on the following business day. To be proper, the shareholder's written notice must set forth as to each matter the shareholder proposes to bring before the annual meeting (a) a brief description of the business desired to be brought before the annual meeting, (b) the name and address of the shareholder as they appear on the Corporation's books, (c) the class and number of shares of the Corporation that are beneficially owned by the shareholder, and (d) any material interest of the shareholder in such business. In addition, if the shareholder's written notice relates to the nomination at the annual meeting of any person for election to the Board, such notice to be proper must also set forth (a) the name, age, business address, and residence address of each person to be so nominated, (b) the principal occupation or employment of each such person, (c) the number of shares of capital stock of the Corporation beneficially owned by each such person, and (d) such other information concerning each such person as would be required under the rules of the Securities and Exchange Commission in a proxy statement soliciting proxies for the election of such person as a Director, and must be accompanied by a consent, signed by each such person, to serve as a Director of the Corporation if elected. Notwithstanding anything in the Bylaws to the contrary, no business shall be conducted at an annual meeting except in accordance with the procedures set forth in this Section .

3. **Special Meetings.** Special meetings of the shareholders shall be called by the Corporate Secretary or an Assistant Corporate Secretary at any time on order of the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board,

the Chairman of the Executive Committee, or the President. Special meetings of the shareholders shall also be called by the Corporate Secretary or an Assistant Corporate Secretary upon the written request of holders of shares entitled to cast not less than ten percent of the votes at the meeting. Such request shall state the purposes of the meeting, and shall be delivered to the Chairman of the Board, the Vice Chairman of the Board, the Chairman of the Executive Committee, the President or the Corporate Secretary.

A special meeting so requested shall be held on the date requested, but not less than thirty-five nor more than sixty days after the date of the original request. Written notice of each special meeting of shareholders, stating the place, day, and hour of such meeting and the business proposed to be transacted thereat, shall be given in the manner stipulated in Article I, Section 2, Paragraph 3 of these Bylaws within twenty days after receipt of the written request.

4. **Voting at Meetings.** At any meeting of the shareholders, each holder of record of stock shall be entitled to vote in person or by proxy. The authority of proxies must be evidenced by a written document signed by the shareholder and must be delivered to the Corporate Secretary of the Corporation prior to the commencement of the meeting.

5. **No Cumulative Voting.** No shareholder of the Corporation shall be entitled to cumulate his or her voting power.

Article II.

DIRECTORS.

1. **Number.** The Board of Directors of this Corporation shall consist of such number of directors, not less than nine (9) nor more than seventeen (17). The exact number of directors shall be ten (10) until changed, within the limits specified above, by an amendment to this Bylaw duly adopted by the Board of Directors or the shareholders.

2. **Powers.** The Board of Directors shall exercise all the powers of the Corporation except those which are by law, or by the Articles of Incorporation of this Corporation, or by the Bylaws conferred upon or reserved to the shareholders.

3. **Committees.** The Board of Directors may, by resolution adopted by a majority of the authorized number of directors, designate and appoint one or more committees as the Board deems appropriate, each consisting of two or more directors, to serve at the pleasure of the Board; provided, however, that, as required by this Corporation's Articles of Incorporation, the members of the Executive Committee (should the Board of Directors designate an Executive Committee) must be appointed by the affirmative vote of two-thirds of the authorized number of directors. Any such committee, including the Executive Committee, shall have the authority to act in the manner and to the extent provided in the resolution of the Board of Directors designating such committee and may have all the authority of the Board of Directors, except with respect to the matters set forth in California Corporations Code Section 311.

4. **Time and Place of Directors' Meetings.** Regular meetings of the Board of Directors shall be held on such days and at such times and at such locations as shall be fixed by resolution of the Board, or designated by the Chairman of the Board or, in his absence, the Vice Chairman of the Board, or the President of the Corporation and contained in the notice of any such meeting. Notice of meetings shall be delivered personally or sent by mail or telegram at least seven days in advance.

5. **Special Meetings.** The Chairman of the Board, the Vice Chairman of the Board, the Chairman of the Executive Committee, the President, or any five directors may call a special meeting of the Board of Directors at any time. Notice of the time and place of special meetings shall be given to each Director by the Corporate Secretary. Such notice shall be delivered personally or by telephone (or other system or technology designed to record and communicate messages, including facsimile, electronic mail, or other such means) to each Director at least four hours in advance of such meeting, or sent by first-class mail or telegram, postage prepaid, at least two days in advance of such meeting.

6. **Quorum.** A quorum for the transaction of business at any meeting of the Board of Directors or any committee thereof shall consist of one-third of the authorized number of directors or committee members, or two, whichever is larger.

7. **Action by Consent.** Any action required or permitted to be taken by the Board of Directors may be taken without a meeting if all Directors individually or collectively consent in writing to such action. Such written consent or consents shall be filed with the minutes of the proceedings of the Board of Directors.

8. **Meetings by Conference Telephone.** Any meeting, regular or special, of the Board of Directors or of any committee of the Board of Directors, may be held by conference telephone or similar communication equipment, provided that all Directors participating in the meeting can hear one another.

Article III.

OFFICERS.

1. **Officers.** The officers of the Corporation shall be a Chairman of the Board, a Vice Chairman of the Board, a Chairman of the Executive Committee (whenever the Board of Directors in its discretion fills these offices), a President, one or more Vice Presidents, a Corporate Secretary and one or more Assistant Corporate Secretaries, a Treasurer and one or more Assistant Treasurers, a General Counsel, a General Attorney (whenever the Board of Directors in its discretion fills this office), and a Controller, all of whom shall be elected by the Board of Directors. The Chairman of the Board, the Vice Chairman of the Board, the Chairman of the Executive Committee, and the President shall be members of the Board of Directors.

2. **Chairman of the Board.** The Chairman of the Board, if that office be filled, shall preside at all meetings of the shareholders, of the Directors, and of the Executive Committee in the absence of the Chairman of that Committee. The Chairman of the Board shall be the chief executive officer of the Corporation if so designated by the Board of Directors. The Chairman of the Board shall have such duties and responsibilities as may be prescribed by the Board of Directors or the Bylaws. The Chairman of the Board shall have authority to sign on behalf of the Corporation agreements and instruments of every character, and in the absence or disability of the President, shall exercise his duties and responsibilities.

3. **Vice Chairman of the Board.** The Vice Chairman of the Board, if that office be filled, shall have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, or the Bylaws. The Vice Chairman of the Board shall be the chief executive officer of the Corporation if so designated by the Board of Directors. In the absence of the Chairman of the Board, the Vice Chairman of the Board shall preside at all meetings of the Board of Directors and of the shareholders; and, in the absence of the Chairman of the Executive Committee and the Chairman of the Board, The Vice Chairman of the Board shall preside at all meetings of the Executive Committee. The Vice Chairman of the Board shall have authority to sign on behalf of the Corporation agreements and instruments of every character.

4. **Chairman of the Executive Committee.** The Chairman of the Executive Committee, if that office be filled, shall preside at all meetings of the Executive Committee. The Chairman of the Executive Committee shall aid and assist the other officers in the performance of their duties and shall have such other duties as may be prescribed by the Board of Directors or the Bylaws.

5. **President.** The President shall have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, or the Bylaws. The President shall be the chief executive officer of the Corporation if so designated by the Board of Directors. If there be no Chairman of the Board, the President shall also exercise the duties and responsibilities of that office. The President shall have authority to sign on behalf of the Corporation agreements and instruments of every character.

6. **Vice Presidents.** Each Vice President shall have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Bylaws. Each Vice President's authority to sign agreements and instruments on behalf of the Corporation shall be as prescribed by the Board of Directors. The Board of Directors of this company, the Chairman of the Board of this company, the Vice Chairman of the Board of this company, or the Chief Executive Officer of PG&E Corporation may confer a special title upon any Vice President.

7. **Corporate Secretary.** The Corporate Secretary shall attend all meetings of the Board of Directors and the Executive Committee, and all meetings of the shareholders, and the Corporate Secretary shall record the minutes of all proceedings in books to be kept for that purpose. The Corporate Secretary shall be responsible for maintaining a proper share register and stock transfer books for all classes of shares issued by the Corporation. The Corporate Secretary shall give, or cause to be given, all notices required either by law or the Bylaws. The Corporate Secretary shall keep the seal of the Corporation in safe custody, and shall affix the seal of the Corporation to any instrument requiring it and shall attest the same by the Corporate Secretary's signature.

The Corporate Secretary shall have such other duties as may be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Bylaws.

The Assistant Corporate Secretaries shall perform such duties as may be assigned from time to time by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Corporate Secretary. In the absence or disability of the Corporate Secretary, the Corporate Secretary's duties shall be performed by an Assistant Corporate Secretary.

8. **Treasurer.** The Treasurer shall have custody of all moneys and funds of the Corporation, and shall cause to be kept full and accurate records of receipts and disbursements of the Corporation. The Treasurer shall deposit all moneys and other valuables of the Corporation in the name and to the credit of the Corporation in such depositories as may be designated by the Board of Directors or any employee of the Corporation designated by the Board of Directors. The Treasurer shall disburse such funds of the Corporation as have been duly approved for disbursement.

The Treasurer shall perform such other duties as may from time to time be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Bylaws.

The Assistant Treasurer shall perform such duties as may be assigned from time to time by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Treasurer. In the absence or disability of the Treasurer, the Treasurer's duties shall be performed by an Assistant Treasurer.

9. **General Counsel.** The General Counsel shall be responsible for handling on behalf of the Corporation all proceedings and matters of a legal nature. The General Counsel shall render advice and legal counsel to the Board of Directors, officers, and employees of the Corporation, as necessary to the proper conduct of the business. The General Counsel shall keep the management of the Corporation informed of all significant developments of a legal nature affecting the interests of the Corporation.

The General Counsel shall have such other duties as may from time to time be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Bylaws.

10. **Controller.** The Controller shall be responsible for maintaining the accounting records of the Corporation and for preparing necessary financial reports and statements, and the Controller shall properly account for all moneys and obligations due the Corporation and all properties, assets, and liabilities of the Corporation. The Controller shall render to the officers such periodic reports covering the result of operations of the Corporation as may be required by them or any one of them.

The Controller shall have such other duties as may from time to time be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Bylaws. The Controller shall be the principal accounting officer of the Corporation, unless another individual shall be so designated by the Board of Directors.

Article IV.

MISCELLANEOUS.

1. **Record Date.** The Board of Directors may fix a time in the future as a record date for the determination of the shareholders entitled to notice of and to vote at any meeting of shareholders, or entitled to receive any dividend or distribution, or allotment of rights, or to exercise rights in respect to any change, conversion, or exchange of shares. The record date so fixed shall be not more than sixty nor less than ten days prior to the date of such meeting nor more than sixty days prior to any other action for the purposes for which it is so fixed. When a record date is so fixed, only shareholders of record on that date are entitled to notice of and to vote at the meeting, or entitled to receive any dividend or distribution, or allotment of rights, or to exercise the rights, as the case may be.

2. **Transfers of Stock.** Upon surrender to the Corporate Secretary or Transfer Agent of the Corporation of a certificate for shares duly endorsed or accompanied by proper evidence of succession, assignment, or authority to transfer, and payment of transfer taxes, the Corporation shall issue a new certificate to the person entitled thereto, cancel the old certificate, and record the transaction upon its books. Subject to the foregoing, the Board of Directors shall have power and authority to make such rules and regulations as it shall deem necessary or appropriate concerning the issue, transfer, and registration of certificates for shares of stock of the Corporation, and to appoint and remove Transfer Agents and Registrars of transfers.

3. **Lost Certificates.** Any person claiming a certificate of stock to be lost, stolen, mislaid, or destroyed shall make an affidavit or affirmation of that fact and verify the same in such manner as the Board of Directors may require, and shall, if the Board of Directors so requires, give the Corporation, its Transfer Agents, Registrars, and/or other agents a bond of indemnity in form approved by counsel, and in amount and with such sureties as may be satisfactory to the Corporate Secretary of the Corporation, before a new certificate may be issued of the same tenor and for the same number of shares as the one alleged to have been lost, stolen, mislaid, or destroyed.

Article V.

AMENDMENTS.

1. **Amendment by Shareholders.** Except as otherwise provided by law, these Bylaws, or any of them, may be amended or repealed or new Bylaws adopted by the affirmative vote of a majority of the outstanding shares entitled to vote at any regular or

special meeting of the shareholders.

2. **Amendment by Directors.** To the extent provided by law, these Bylaws, or any of them, may be amended or repealed or new Bylaws adopted by resolution adopted by a majority of the members of the Board of Directors.

EXECUTION COPY

GOLDMAN SACHS & CO. | 85 BROAD STREET | NEW YORK, NEW YORK 10004 | TEL: 212-902-1000

To: PG&E Corporation
One Market Spear Tower
Suite 2400
San Francisco, CA 94105

From: Goldman, Sachs & Co.

Subject: Accelerated Share Repurchase Transaction -
VWAP Pricing (Non-Collared)

Ref. No: EN50BJ000000000

Date: March 4, 2005

This master confirmation ("Master Confirmation") dated as of March 4, 2005, is intended to supplement the terms and provisions of certain Transactions (each, a "Transaction") entered into from time to time between Goldman, Sachs & Co. ("GS&Co.") and PG&E Corporation ("Counterparty"). This Master Confirmation, taken alone, is neither a commitment by either party to enter into any Transaction nor evidence of a Transaction. The terms of any particular Transaction shall be set forth in a Supplemental Confirmation in the form of Annex A, which references this Master Confirmation, in which event the terms and provisions of this Master Confirmation shall be deemed to be incorporated into and made a part of each such Supplemental Confirmation. This Master Confirmation and each Supplemental Confirmation together shall constitute a "Confirmation" as referred to in the Agreement specified below.

The definitions and provisions contained in the 2002 ISDA Equity Derivatives Definitions (the "Equity Definitions"), as published by the International Swaps and Derivatives Association, Inc., are incorporated into this Master Confirmation. This Master Confirmation and each Supplemental Confirmation evidences a complete binding agreement between the Counterparty and GS&Co. as to the terms of each Transaction to which this Master Confirmation and the related Supplemental Confirmation relates.

This Master Confirmation and each Supplemental Confirmation, together with all other documents referring to the 1992 ISDA Master Agreement (Multicurrency-Cross Border) (the "ISDA Form" or the "Agreement"), confirming Transactions entered into between GS&Co. and Counterparty, shall supplement, form a part of, and be subject to the ISDA Form as if GS&Co. and Counterparty had executed the Agreement (but without any Schedule) except that the following elections and modifications shall be made: (i) the election of Loss and Second Method, New York law (without regard to conflicts of law principles) as the governing law and US Dollars ("USD") as the Termination Currency, (ii) the election that subparagraph (ii) of Section 2(c) will not apply to Transactions, (iii) the replacement of the word "third" in the last line of Section 5(a)(i) with the word "first", (iv) the election that the "Cross Default" provisions of Section 5(a)(vi) shall apply to Counterparty, with a "Threshold Amount" of USD 75 million, and (v) the replacement of clause (1) in Section 6(d)(i) with the clause "(1) showing in reasonable detail such calculations and specifying any amount payable under Section 6(e) (including, without limitation, providing all relevant quotations and assumptions and specifying the methodologies used in sufficient detail so as to enable the other party to replicate the calculation)". Further, for purposes of determining whether an Event of Default pursuant to Section 5(a)(vi) of the Agreement has occurred, notwithstanding anything to the contrary stated in that provision, clause (1) of Section 5(a)(vi) will apply only to Specified Indebtedness that is actually declared to be due and payable before it would otherwise be due and payable under the relevant agreement or instrument, and not to Specified Indebtedness that is merely "capable at such time of being declared" so due and payable.

All provisions contained in the Agreement shall govern this Master Confirmation and the related Supplemental Confirmation relating to a Transaction except as expressly modified herein or in the related Supplemental Confirmation. With respect to any relevant Transaction, the Agreement, this Master Confirmation and the related Supplemental Confirmation shall represent the entire agreement and understanding of the parties with respect to the subject matter and terms of such Transaction and shall supersede all prior or contemporaneous written or oral communications with respect thereto.

If, in relation to any Transaction to which this Master Confirmation and related Supplemental Confirmation relate, there is any inconsistency between the Agreement, this Master Confirmation, any Supplemental Confirmation and the Equity Definitions that are incorporated into this Master Confirmation or any Supplemental Confirmation, the following will prevail for purposes of such Transaction in the order of precedence indicated: (i) such Supplemental Confirmation; (ii) this Master Confirmation; (iii) the Agreement; and (iv) the Equity Definitions.

1. Each Transaction constitutes a Share Forward Transaction for the purposes of the Equity Definitions. Set forth below are the terms and conditions which, together with the terms and conditions set forth in each Supplemental Confirmation (in respect of each relevant Transaction), shall govern each such Transaction.

General Terms:

Trade Date:	For each Transaction, as set forth in the Supplemental Confirmation.
Seller:	Counterparty
Buyer:	GS&Co.
Shares:	Common Stock of PG&E Corp. (Ticker: PCG)
Number of Shares:	For each Transaction, as set forth in the Supplemental Confirmation.
Forward Price:	For each Transaction, as set forth in the Supplemental Confirmation.
Prepayment:	Not Applicable
Variable Obligation:	Not Applicable
Exchange:	New York Stock Exchange
Related Exchange(s):	All Exchanges
Market Disruption Event:	The definition of "Market Disruption Event" in Section 6.3(a) of the Equity Definitions is hereby amended by inserting the words "at any time on any Scheduled Trading Day during the Valuation Period or" after the word "material," in the third line thereof.

Valuation:

Valuation Period:	Each Scheduled Trading Day during the period commencing on and including the Valuation Period Start Date to and including the Valuation Date (but excluding any day(s) on which the Valuation Period is suspended in accordance with Section 5 herein and including any day(s) by which the Valuation Period is extended pursuant to the provision below).
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Notwithstanding anything to the contrary in the Equity Definitions, to the extent that any Scheduled Trading Day in the Valuation Period is a Disrupted Day, the Valuation Date shall be postponed and the Calculation Agent in its sole discretion shall extend the Valuation Period and make adjustments to the weighting of each Relevant Price for purposes of determining the Settlement Price, with such adjustments based on, among other factors, the duration of any Market Disruption Event and the volume, historical trading patterns and price of the Shares. To the extent that there are 9 consecutive Disrupted Days during the Valuation Period, then notwithstanding the occurrence of a Disrupted Day, the Calculation Agent shall have the option in its sole discretion to either determine the Relevant Price using its good faith estimate of the value for the Share on such 9th consecutive day or elect to further extend the Valuation Period as it deems necessary.

Valuation Period Start Date:	For each Transaction, as set forth in the Supplemental Confirmation.
Valuation Date:	For each Transaction, as set forth in the Supplemental Confirmation (as the same may be postponed in accordance with the provisions of "Valuation Period" and Section 5 herein).
Settlement Terms:	
Settlement Currency:	USD (all amounts shall be converted to the Settlement Currency in good faith and in a commercially reasonable manner by the Calculation Agent).
Settlement Method Election:	Applicable; provided that (a) Section 7.1 of the Equity Definitions is hereby amended by deleting the word "Physical" in the sixth line thereof and replacing it with the words "Net Share" and deleting the word "Physical" in the last line thereof and replacing it with word "Cash" and (b) in the event that GS&Co. would deliver to the Counterparty an amount of Shares under Net Share Settlement, Cash Settlement shall be applicable in lieu of Net Share Settlement.
Electing Party:	Counterparty
Settlement Method Election Date:	10 Scheduled Trading Days prior to the originally scheduled Valuation Date.
Default Settlement Method:	Cash Settlement
Forward Cash Settlement Amount:	An amount in the Settlement Currency equal to the product of (a) the Number of Shares multiplied by (b) an amount equal to (i) the Settlement Price minus (ii) the Forward Price.
Settlement Price:	The arithmetic mean of the Relevant Prices of the Shares for each Exchange Business Day in the Valuation Period.

Relevant Price: The New York 10b-18 Volume Weighted Average Price per share of the Shares for the regular trading session (including any extensions thereof) of the Exchange on the related Exchange Business Day (without regard to pre-open or after hours trading outside of such regular trading session) as published by Bloomberg at 4:15 p.m. New York time on such date.

Cash Settlement
Payment Date: 3 Currency Business Days after the Valuation Date.

Counterparty's Contact
Details for Purpose of
Giving Notice: Nicholas Bijur
Assistant Treasurer
PG&E Corporation
One Market Street, Spear Tower
Suite 2400
San Francisco, CA 94105
Telephone No.: (415) 817-8199
Facsimile No.: (415) 267-7265

With a copy to:
Gary Encinas
Chief Counsel-Corporate
PG&E Corporation
One Market Street, Spear Tower
Suite 2400
San Francisco, CA 94105
Telephone No.: (415) 817-8201
Facsimile No.: (415) 817-8225

GS&Co.'s Contact
Details for Purpose of
Giving Notice: Telephone No.: (212) 902-8996
Facsimile No.: (212) 902-0112
Attention: Equity Operations: Options and Derivatives

With a copy to:
Kelly Coffey
Equity Capital Markets
One New York Plaza
New York, NY 10004
Telephone No.:
(212) 902-1037
Facsimile No.:
(212) 346-2126

Net Share Settlement:

Net Share Settlement
Procedures: Net Share Settlement shall be made in accordance with the procedures attached hereto as Annex B.

Net Share Settlement
Price: The Net Share Settlement Price shall be the price per Share as of the Valuation Time on the Net Share Valuation Date as reported in the

official real-time price dissemination mechanism for the Exchange. The Net Share Settlement Price shall be reduced by the per Share amount of the underwriting discount and/or commissions agreed to pursuant to the equity underwriting or agency agreement contemplated by the Net Share Settlement Procedures.

Valuation Time: As provided in Section 6.1 of the Equity Definitions; provided that Section 6.1 of the Equity Definitions is hereby amended by inserting the words "Net Share," before the words "Valuation Date" in the first and third lines thereof.

Net Share Valuation Date: The Exchange Business Day immediately following the Valuation Date.

Net Share Settlement Date: The third Exchange Business Day immediately following the Valuation Date.

Reserved Shares: For each Transaction, as set forth in the Supplemental Confirmation.

Fixed, Floating and Counterparty
Additional Payment Amounts Payable:

Floating Amount Payable by GS&Co.:

Floating Amount Payment Date: The Cash Settlement Payment Date

Floating Amount: For each Transaction, an amount equal to the sum of the applicable Federal Funds Rate multiplied by (i) the Daily Notional Amount multiplied by (ii) 1/360 for each day from and including the Floating Amount Accrual Date to and including the Valuation Date.

Floating Amount Accrual Date: Trade Date

Federal Funds Rate: For any date of determination, the "Fed Funds Open Rate," which shall be the interest rate reported on Bloomberg under the symbol "FEDSOPEN <index>" on such date. For the avoidance of doubt, for any day which is not a Currency Business Day the "Federal Funds Open Rate" for the immediately preceding Currency Business Day shall apply.

Daily Notional Amount: Commencing with the Floating Amount Accrual Date, for any date of determination, the Daily Notional Amount shall be an amount equal to the product of the Initial Notional Amount (as set forth in the Supplemental Confirmation) multiplied by a fraction with a numerator equal to the Originally Scheduled Number of Scheduled Trading Days in the Valuation Period minus the number of Exchange Business Days in the Valuation Period that have elapsed (other than any days during which the Valuation Period is suspended pursuant to Section 5 herein) as of

such date of determination and a denominator equal to the Originally Scheduled Number of Scheduled Trading Days in the Valuation Period (such fraction, the "Remaining Percentage").

To the extent that the Valuation Period is extended pursuant to the terms of this Master Confirmation, the Calculation Agent shall adjust the Daily Notional Amount commencing with the first Exchange Business Day after such extension (the "Valuation Period Extension Date"). The notional amount deemed to be remaining at the end of the Exchange Business Day before the Valuation Period Extension Date (the "Remaining Notional Value") shall be the Initial Notional Value multiplied by the Remaining Percentage at the end of such day. Commencing with the Valuation Period Extension Date, for any date of determination, the Daily Notional Amount shall be equal to the product of the Remaining Notional Value multiplied by a fraction with (a) a numerator equal to (i) the number of Scheduled Trading Days remaining from and including the Valuation Period Extension Date to the Valuation Date after extension (the "Remaining Scheduled Trading Days") minus (ii) the number of Exchange Business Days in the Valuation Period after extension from and including the Valuation Period Extension Date that have elapsed (other than any days during which the Valuation Period after extension is suspended pursuant to Section 5 herein) as of such date of determination and (b) a denominator equal to the Remaining Scheduled Trading Days.

Fixed Amount Payable by Counterparty:

Fixed Amount Payment
Date:

The Cash Settlement Payment Date

Fixed Amount:

For each Transaction, an amount equal to the sum of (I) the applicable Daily Additional Spread multiplied by (i) the Daily Notional Amount multiplied by (ii) 1/360 for each day from and including the Floating Amount Accrual Date to and including the Valuation Date plus (II) an amount equal to the sum of the applicable Fixed Rate multiplied by (i) the Notional Amount multiplied by (ii) 1/360 for each day from and including the Floating Amount Accrual Date to and including the Valuation Date.

Fixed Rate:

For each Transaction, as set forth in the Supplemental Confirmation.

Daily Additional Spread:

The Additional Spread shall be 25 basis points

Notional Amount:

For any date of determination, 105% of the Daily Notional Amount.

Counterparty Additional Amount
Payable by Company:

Counterparty Additional
Payment Amount:

For each Transaction, as set forth in the Supplemental Confirmation.

Counterparty Additional
Payment Date:

The Cash Settlement Payment Date.

Settlement Terms for Fixed Amount and
Counterparty Additional Payment Amount:

Settlement Currency:

USD (all amounts shall be converted to the Settlement Currency in good faith and in a commercially reasonable manner by the Calculation Agent).

Settlement Method
Election:

Applicable; provided that Section 7.1 of the Equity Definitions is hereby amended by deleting the word "Physical" in the sixth line thereof and replacing it with the words "Net Share" and deleting the word "Physical" in the last line thereof and replacing it with the word "Cash".

Electing Party:

Counterparty

Settlement Method
Election Date:

10 Scheduled Trading Days prior to the originally scheduled Valuation Date.

Default Settlement
Method:

Cash Settlement

Share Adjustments:

Method of Adjustment:

Calculation Agent Adjustment

Extraordinary Events:

Consequences of Merger Events:

Subject to Section 7(b) of the Master Confirmation:

(a) Share-for-Share:

Modified Calculation Agent Adjustment

(b) Share-for-Other:

Cancellation and Payment on that portion of the Other Consideration that consists of cash; Modified Calculation Agent Adjustment on the remainder of the Other Consideration.

(c) Share-for-
Combined:

Component Adjustment

Determining Party:

GS&Co.

Tender Offer:

Applicable

Consequences of Tender Offers:

Subject to Section 7(b) of the Master Confirmation:

- | | |
|-------------------------|---|
| (a) Share-for-Share: | Modified Calculation Agent Adjustment |
| | |
| (b) Share-for-Other: | Cancellation and Payment on that portion of the Other Consideration that consists of cash; Modified Calculation Agent Adjustment on the remainder of the Other Consideration. |
| | |
| (c) Share-for-Combined: | Component Adjustment |

Determining Party:	GS&Co.
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Nationalization, Insolvency or Delisting:

Subject to Section 7(a) of this Master Confirmation, Negotiated Close-out; provided that in addition to the provisions of Section 12.6(a)(iii) of the Equity Definitions, it shall also constitute a Delisting if the Exchange is located in the United States and the Shares are not immediately re-listed, re-traded or re-quoted on any of the New York Stock Exchange, the American Stock Exchange or The NASDAQ National Market (or their respective successors); if the Shares are immediately re-listed, re-traded or re-quoted on any such exchange or quotation system, such exchange or quotation system shall be deemed to be the Exchange.

Additional Disruption Events:

- | | |
|---------------------------|---|
| (a) Change in Law: | Applicable; provided that Section 12.9(a)(ii)(Y) of the Equity Definitions is hereby deleted. |
| | |
| (b) Failure to Deliver: | Not Applicable |
| | |
| (c) Insolvency Filing: | Applicable |
| | |
| (d) Loss of Stock Borrow: | Applicable; provided that Loss of Stock Borrow shall not constitute an Additional Disruption Event so long as Counterparty agrees to pay the Hedging Party the amount by which the stock loan rate necessary to maintain a borrowing of Shares by GS&Co. ("Hedge Position") in connection with the Transaction exceeds the Maximum Stock Loan Rate. |
| | |
| Maximum Stock Loan Rate | 30 basis points |
| | |
| (e) Hedging Disruption: | Not Applicable. |

(f) Increased Cost of Hedging:	Not Applicable.
(g) Increased Cost of Stock Borrow:	Not Applicable.
Hedging Party:	GS&Co.
Determining Party:	GS&Co.
Non-Reliance:	Applicable
Agreements and Acknowledgements Regarding Hedging Activities:	Applicable
Additional Acknowledgements:	Applicable
Net Share Settlement following Extraordinary Event:	Counterparty shall have the right, in its sole discretion, to make any payment required to be made by it pursuant to Sections 12.7 or 12.9 of the Equity Definitions (except with respect to any portion of the consideration for the Shares consisting of cash in the event of a Merger Event or Tender Offer) following the occurrence of an Extraordinary Event by electing to Net Share Settle the Transactions under this Master Confirmation in accordance with the terms, and subject to the conditions, for Net Share Settlement herein by giving written notice to GS&Co. of such election on the day that the notice fixing the date that the Transactions are terminated or cancelled, as the case may be, (the "Cancellation Date") pursuant to the applicable provisions of Section 12 of the Equity Definitions is effective. If Counterparty elects Net Share Settlement: (a) the Net Share Valuation Date shall be the date specified in the notice fixing the date that the Transactions are terminated or cancelled, as the case may be; provided that the Net Share Valuation Date shall be either the Exchange Business Day that such notice is effective or the first Exchange Business Day immediately following the Exchange Business Day that such notice is effective, (b) the Net Share Settlement Date shall be deemed to be the Exchange Business Day immediately following the Cancellation Date and (c) all references to the Forward Cash Settlement Amount, the Fixed Amount and the Counterparty Additional Payment Amount, as the case may be, in Annex B hereto shall be deemed to be references to the Cancellation Amount. The definition of "Cancellation Amount" in Section 12.8 of the Equity Definitions is hereby amended by inserting the following paragraph: "(h) The Determining Party shall show the other party in reasonable detail its calculation of the Cancellation Amount, including without limitation providing all relevant quotations and assumptions and specifying the methodologies used in sufficient detail so as to enable the other party to replicate the calculation".

Net Share Settlement
Upon Early Termination:

Counterparty shall have the right, in its sole discretion, to make any payment required to be made by it (the "Early Termination Amount") pursuant to Sections 6(d) and 6(e) of the Agreement following the occurrence of an Early Termination Date in respect of the Agreement by electing to Net Share Settle all the Transactions under this Master Confirmation in accordance with the terms, and subject to the conditions, for Net Share Settlement herein by giving written notice to GS&Co. of such election on the day that the notice fixing an Early Termination Date is effective. If Counterparty elects Net Share Settlement: (a) the Net Share Valuation Date shall be the date specified in the notice fixing an Early Termination Date; provided that the Net Share Valuation Date shall be either the Exchange Business Day that such notice is effective or the first Exchange Business Day immediately following the Exchange Business Day that such notice is effective, (b) the Net Share Settlement Date shall be deemed to be the Exchange Business Day immediately following the Early Termination Date (except for an Early Termination as a result of Section 7(d), in which event the Net Share Settlement Date shall be deemed to be the tenth Exchange Business Day following the Early Termination Date) and (c) all references to Forward Cash Settlement Amount, the Fixed Amount and the Counterparty Additional Payment Amount, as the case may be, in Annex B hereto shall be deemed references to the Early Termination Amount.

Transfer:

Notwithstanding anything to the contrary in the Agreement, GS&Co. may assign, transfer and set over all rights, title and interest, powers, privileges and remedies of GS&Co. under any Transaction, in whole or in part, to an affiliate of GS&Co. that is fully and unconditionally guaranteed by The Goldman Sachs Group, Inc. without the consent of Counterparty, provided that Counterparty is not required to make a payment to GS&Co. in respect of an Indemnifiable Tax as a result of such transfer.

GS&Co. Payment
Instructions:

Chase Manhattan Bank New York
For A/C Goldman, Sachs & Co.
A/C # 930-1-011483
ABA: 021-000021

Counterparty Payment
Instructions:

PG&E Corporation Master Account No. 099023
Mellon Trust of New England, N.A.
Boston, MA
ABA Routing No: 011001234

2. Calculation Agent : GS&Co.

3. Representations, Warranties and Covenants of GS&Co. and Counterparty.

(a) Each party represents and warrants that it (i) is an "eligible contract participant", as defined in the U.S. Commodity Exchange Act, as amended and (ii) is entering into each Transaction hereunder as principal (and not as agent or in any other capacity, fiduciary or otherwise) and not for the benefit of any third party.

(b) Each party acknowledges that the offer and sale of each Share Forward Transaction to it is intended to be exempt from registration under the Securities Act of 1933, as amended (the "Securities Act"), by virtue of Section 4(2) thereof and the provisions of Regulation D promulgated thereunder ("Regulation D"); and this acknowledgement shall not be deemed to extend to Settlement Shares or Early Settlement Shares. Accordingly, each party represents and warrants to the other that (i) it has the financial ability to bear the economic risk of its investment in each Share Forward Transaction and is able to bear a total

loss of its investment, (ii) it is an "accredited investor" as that term is defined under Regulation D, (iii) it will purchase each Share Forward Transaction for investment and not with a view to the distribution or resale thereof, and (iv) the disposition of each Share Forward Transaction is restricted under this Master Confirmation and each Supplemental Confirmation, the Securities Act and state securities laws.

4. Additional Representations, Warranties and Covenants of Counterparty.

As of the date hereof and the date of each Supplemental Confirmation, Counterparty represents, warrants and covenants to GS&Co. that:

(a) the purchase or writing of each Transaction will not violate Rule 13e-1 or Rule 13e-4 under the Securities Exchange Act of 1934, as amended (the "Exchange Act");

(b) is not entering into any Transaction on the basis of, and is not aware of, any material non-public information with respect to the Shares or in anticipation of, in connection with, or to facilitate, a distribution of its securities, a self tender offer or a third-party tender offer;

(c) it is not entering into any Transaction to create, and will not engage in any other securities or derivative transaction to create, a false or misleading appearance of active trading or market activity in the Shares (or any security convertible into or exchangeable for the Shares), or which would otherwise violate the Exchange Act;

(d) Counterparty is in compliance with its reporting obligations under the Exchange Act and its most recent Annual Report on Form 10-K, together with all reports subsequently filed by it pursuant to the Exchange Act, taken together and as amended and supplemented to the date of this representation, do not, as of their respective filing dates, contain any untrue statement of a material fact or omit any material fact required to be stated therein or necessary to make the statements therein, in the light of the circumstances in which they were made, not misleading;

(e) each Transaction is being entered into pursuant to a publicly disclosed Share buy-back program and its Board of Directors has approved the use of the Transaction to effect the Share buy-back program;

(f) notwithstanding the generality of Section 13.1 of the Equity Definitions, GS&Co. is not making any representations or warranties with respect to the treatment of any Transaction under FASB Statements 149 or 150, EITF 00-19 (or any successor issue statements) or under FASB's Liabilities & Equity Project;

(g) it has not, and during any Valuation Period (as extended pursuant to the provisions of Section 5 and "Valuation Period" herein) will not, enter into agreements similar to the Transactions described herein except with GS&Co. or an entity affiliated with GS&Co. where the valuation period in such other transaction will overlap at any time (including as a result of extensions in such valuation period as provided in the relevant agreements) with any Valuation Period (as extended pursuant to the provisions of Section 5 and "Valuation Period" herein) under this Master Confirmation. In the event that the valuation period in any other similar transaction with an entity other than GS&Co. or an entity affiliated with GS&Co. overlaps with any Valuation Period under this Master Confirmation as a result of any extension made pursuant to the provisions of Section 5 and "Valuation Period" herein, Counterparty shall promptly amend such transaction to avoid any such overlap; and

(h) it shall report each Transaction as required under the Exchange Act and the regulations promulgated thereunder.

5. Suspension of Valuation Period; Extension of Valuation Period.

(a) If Counterparty concludes that it will be engaged in a distribution of the Shares for purposes of Regulation M promulgated under the Exchange Act ("Regulation M"), Counterparty agrees that it will, on one Scheduled Trading Day's written notice, direct GS&Co. not to purchase Shares in connection with hedging any Transaction during the "restricted period" (as defined in Regulation M). If on any Scheduled Trading Day Counterparty delivers written notice (and confirms by telephone) by 8:30 a.m. New York Time (the "Notification Time"), then such notice shall be effective to suspend the Valuation Period as of such Notification Time. In the event that Counterparty delivers notice and/or confirms by telephone after the Notification Time, then the Valuation Period shall be suspended effective as of 8:30 a.m. New York Time on the following Scheduled Trading Day or as otherwise required by law or agreed between Counterparty and GS&Co. The Valuation Period shall be suspended and the Valuation Date extended for each Scheduled Trading Day in such restricted period.

(b) In the event that GS&Co. concludes, in its reasonable discretion, that it is appropriate with respect to any legal, regulatory or self-regulatory requirements or related policies and procedures (whether or not such requirements, policies or procedures are imposed by law or have been voluntarily adopted by GS&Co.), for it to refrain from purchasing Shares on any Scheduled Trading Day during the Valuation Period, GS&Co. may by written notice to Counterparty elect to suspend the Valuation Period for such number of Scheduled Trading Days as is specified in the notice. The notice shall not specify, and GS&Co. shall not otherwise communicate to Counterparty, the reason for GS&Co.'s election to suspend the Valuation Period.

The Valuation Period shall be suspended and the Valuation Date extended for each Scheduled Trading Day occurring during any such suspension.

(c) In the event that the Valuation Period is suspended pursuant to Sections 5(a) or (b) above during the regular trading session on the Exchange, then the Calculation Agent in its sole discretion shall, in calculating the Forward Cash Settlement Amount, extend the Valuation Period and make adjustments to the weighting of each Relevant Price for purposes of determining the Settlement Price, with such adjustments based on, among other factors, the duration of any such suspension and the volume, historical trading patterns and price of the Shares.

(d) On the first Exchange Business Day of each calendar week during the Valuation Period, to the extent that the Number of Daily Reference Shares exceeds 25% of the ADTV (as defined in Rule 10b-18 under the Exchange Act ("Rule 10b-18")) for the Shares on such day, the Calculation Agent will (i) adjust the Number of Daily Reference Shares to equal an amount equal to 15% of ADTV for the Shares determined and effective on such Exchange Business Day and (ii) deem the remaining Scheduled Trading Days in the Valuation Period to be equal to the Remaining Number of Shares divided by the Number of Daily Reference Shares (after giving effect to any adjustments pursuant to (i) above), rounded up to the nearest whole number.

"Number of Daily Reference Shares" means, for each Transaction, initially the Initial Number of Daily Reference Shares (as set forth in the Supplemental Confirmation) and thereafter as may be adjusted in accordance with this Section 5(d); provided that on the first Exchange Business Day of the fifth calendar week following any such adjustment the Number of Daily Reference Shares shall equal the lesser of (i) the Initial Number of Daily Reference Shares and (ii) 15% of the ADTV of the Shares determined on such Exchange Business Day.

"Remaining Number of Shares" means, for each Transaction and as of any date of determination, a number of Shares equal to (i) the Number of Shares minus (ii) the sum of, for each Exchange Business Day in the Valuation Period up to and including such date, the Number of Shares divided by the total number of Exchange Business Days in the Valuation Period (the "Daily Amount"). The Daily Amount will be deemed to be zero for each day on which the Valuation Period is suspended in accordance with Sections 5(a) and (b) hereof. In the event that the Valuation Period is extended pursuant to the terms of this Master Confirmation, the Calculation Agent may make corresponding adjustments to the amount of the Remaining Number of Shares.

6. Counterparty Purchases. Counterparty represents, warrants and covenants to GS&Co. that for each Transaction:

(a) Counterparty (or any "affiliated purchaser" as defined in Rule 10b-18) shall not, purchase any Shares, listed contracts on the Shares or securities that are convertible into, or exchangeable or exercisable for Shares (including, without limitation, any Rule 10b-18 purchases of blocks (as defined in Rule 10b-18)) during any Valuation Period (as extended pursuant to the provisions of Section 5 and "Valuation Period" herein) except for purchases through GS&Co. or an entity affiliated with GS&Co., or if not through GS&Co., with the prior written consent of GS&Co., and in compliance with Rule 10b-18 or otherwise in a manner that Counterparty and GS&Co. believe is in compliance with applicable requirements and except for purchases in connection with management compensation plans or other employee benefit arrangements and except for purchases of the Counterparty's 9.50% Convertible Subordinated Notes due 2010, provided such purchases are made in compliance with any applicable legal regulatory or self-regulatory requirements or related policies and procedures (whether such requirements, policies or procedures are imposed by law or have been voluntarily adopted by GS&Co. for uniform application to all such purchases). Any such purchase by Counterparty shall be disregarded for purposes of determining the Forward Cash Settlement Amount. To the extent that Counterparty makes any such purchase other than through GS&Co., or other than in connection with any Transaction, Counterparty hereby represents and warrants to GS&Co. that (a) it will not take other action that would or could cause GS&Co.'s purchases of the Shares during the Valuation Period not to comply with Rule 10b-18 and (b) any such purchases will not otherwise constitute a violation of Section 9(a) or Rule 10(b) of the Exchange Act. This subparagraph (a) shall not restrict any purchases by Counterparty of Shares effected during any suspension of any Valuation Period in accordance with Section 5 herein and any purchases during such suspension shall be disregarded in calculating the Forward Cash Settlement Amount; and for the avoidance of doubt, this subparagraph (a) shall not restrict any holders of outstanding securities of the Counterparty from exercising or converting such securities to Shares; and

(b) Counterparty is entering into this Master Confirmation and each Transaction hereunder in good faith and not as part of a plan or scheme to evade the prohibitions of Rule 10b5-1 under the Exchange Act ("Rule 10b5-1"). It is the intent of the parties that each Transaction entered into under this Master Confirmation comply with the requirements of Rule 10b5-1(c)(1)(i)(A) and (B) and each Transaction entered into under this Master Confirmation shall be interpreted to comply with the requirements of Rule 10b5-1(c). Counterparty will not seek to control or influence GS&Co. to make "purchases or sales" (within the meaning of Rule 10b5-1(c)(1)(i)(B)(3)) under any Transaction entered into under this Master Confirmation, including, without limitation, GS&Co.'s decision to enter into any hedging transactions. Counterparty represents and warrants that it has consulted with its own advisors as to the legal aspects of its adoption and implementation of this Master Confirmation and each Supplemental Confirmation under Rule 10b5-1.

7. Additional Termination Events. Additional Termination Events will apply under Section 5(b)(v) of the Agreement. The following will constitute Additional Termination Events, in each case with Counterparty as the sole Affected Party:

(a) Notwithstanding anything to the contrary in the Equity Definitions, the occurrence of a Nationalization, Insolvency or a Delisting (in each case effective on the Announcement Date as determined by the Calculation Agent);

(b) Notwithstanding anything to the contrary in the Equity Definitions, the occurrence of a Merger Event (effective on the Merger Date) or a Tender Offer (effective on the Tender Offer Date) in respect of which any Other Consideration received for the Shares does not consist of cash. For the avoidance of doubt, in the event that any portion of the consideration received for the Shares consists of cash or New Shares, this Additional Termination Event shall only apply with respect to all or any Transaction(s) (or portions thereof) remaining after giving effect to the provisions in "Consequences of Merger Events" or "Consequences of Tender Offers", as the case may be, above;

(c) [reserved]; or

(d) Notwithstanding anything to the contrary in the Equity Definitions, one day prior to the ex-dividend date in respect of any Extraordinary Dividend (as specified in the Supplemental Confirmation) by the Issuer; provided that in the event that GS&Co. and Counterparty enter into a mutually acceptable new transaction (using their good faith and commercially reasonable efforts) on or prior to one day prior to the ex-dividend date in respect of the Extraordinary Dividend, the amounts determined pursuant to Section 6(e) of the Agreement or otherwise to be owed by Counterparty and GS&Co. with respect to the Affected Transaction(s) shall be deemed to be only the amounts that would otherwise be owed hereunder in respect of the Forward Cash Settlement Amount (the "Termination Forward Settlement Amount"), the Floating Amount (the "Termination Floating Amount"), the Fixed Amount, (the "Termination Fixed Amount") and the Counterparty Additional Payment Amount if the Early Termination Date were the Cash Settlement Payment Date, and shall be payable in cash or (in the case of the Counterparty) by Net Share Settlement or a combination of the two. In the event that an Early Termination Date would otherwise occur pursuant to this clause 7(d) while the Counterparty is in possession of, or is aware of, material, non-public information, the Early Termination Date shall not be deemed to occur until the day after the day on which Counterparty is not in possession of, and is not aware of, material non-public information so long as, if, at the Counterparty's option, on or prior to one day prior to the ex-dividend date for such Extraordinary Dividend, Counterparty agrees to pay GS&Co. no later than the earlier of the entry into the new transaction or the dividend payment date for such Extraordinary Dividend, a fixed amount in cash or by Net Share Settlement or a combination of the two, that shall be determined in good faith by GS&Co. as having a value equal to (i) the amount per share of such Extraordinary Dividend multiplied by (ii) the actual number of Shares that will remain borrowed by GS&Co. in connection with any Hedge Positions related to the Transaction as of such ex-dividend date. If the Counterparty does not so agree on or prior to one day prior to the ex-dividend date for such Extraordinary Dividend, the Early Termination Date shall occur at the close of business on the Exchange Business Day that is one day prior to the ex-dividend date. For purposes of this Section 7(d): the Termination Forward Settlement Amount shall mean an amount in Settlement Currency equal to the product of (a) the Termination Trading Days multiplied by the Initial Number of Daily Reference Shares multiplied by (b) an amount equal to (i) the Termination Settlement Price minus (ii) the Forward Price; the Termination Floating Amount shall mean an amount equal to the sum of the applicable Federal Funds Rate multiplied by (i) the Daily Notional Amount multiplied by (ii) 1/360 for each day from and including the Floating Amount Accrual Date to but excluding the Early Termination Date; and the Termination Fixed Amount shall mean an amount equal to the sum of (I) the applicable Daily Additional Spread multiplied by (i) the Daily Notional Amount multiplied by (ii) 1/360 for each day from and including the Floating Amount Accrual Date to but excluding the Early Termination Date plus (II) an amount equal to the sum of the applicable Fixed Rate multiplied by (i) the Notional Amount multiplied by (ii) 1/360 for each day from and including the Floating Amount Accrual Date to but excluding the Early Termination Date. Also for purposes of this Section 7(d): "Termination Trading Days" shall mean the number of Exchange Business Days (excluding any day(s) on which the Valuation Period was suspended in accordance with Section 5 herein or as a result of any Scheduled Trading Day being a Disrupted Day) from and including the Valuation Period Start Date to and including the Early Termination Date; "Termination Valuation Period" shall mean the Exchange Business Days during the period commencing on and including the Valuation Period Start Date to and including the Early Termination Date (but excluding any day(s) on which the Valuation Period was suspended in accordance with Section 5 herein or as a result of any Scheduled Trading Day being a Disrupted Day and including any day(s) by which the Valuation Period was extended pursuant to the provision below); and the "Termination Settlement Price" shall mean the arithmetic mean of the Relevant Prices of the Shares for each Exchange Business Day in the Termination Valuation Period.

8. Automatic Termination Provisions. Notwithstanding anything to the contrary in Section 6 of the Agreement:

(a) An Additional Termination Event with Counterparty as the sole Affected Party will automatically occur without any notice or action by GS&Co. or Counterparty if the price of the Shares on the Exchange at any time falls below the Termination Price (as specified in the related Supplemental Confirmation) provided that (for the avoidance of doubt only) such Additional Termination Event shall be an Additional Termination Event only with respect to the Transaction documented in such related Supplemental Confirmation. The Exchange Business Day that the price of the Shares on the Exchange at any time falls below the Termination Price will be the "Early Termination Date" for purposes of the Agreement.

(b) Notwithstanding anything to the contrary in Section 6(d) of the Agreement, following the occurrence of such an Additional Termination Event, GS&Co. will notify Counterparty of the amount owing under Section 6(e) of the Agreement within a commercially reasonable time period (with such period based upon the amount of time, determined by GS&Co. (or any of its Affiliates) in its reasonable discretion, that it would take to unwind any of its Hedge Position(s) related to the Transaction in a commercially reasonable manner based on relevant market indicia). For purposes of the "Net Share

Settlement Upon Early Termination" provisions herein, (i) the date that such notice is effective (the "Notice Date") shall constitute the "Net Share Valuation Date", (ii) the Exchange Business Day immediately following the Notice Date shall be the Net Share Settlement Date and (iii) all references to the Forward Cash Amount or the Fixed Amount in Annex B hereto shall be deemed to be the Early Termination Amount. For the avoidance of doubt, Hedge Position shall only mean any purchase, sale, entry into or maintenance of one or more stock borrowing transactions by GS&Co. or its Affiliates in respect of the Shares in connection with this Transaction and, notwithstanding the forgoing portions of this paragraph and Sections 6(d) and (e) of the Agreement, Counterparty shall be entitled to satisfy the Hedge Position by delivery of the Number of Early Settlement Shares as defined in and pursuant to the provisions of Section 10.

9. Special Provisions for Merger Events. Notwithstanding anything to the contrary herein or in the Equity Definitions, to the extent that an Announcement Date for a potential Merger Transaction occurs during any Valuation Period:

(a) Promptly after request from GS&Co., Counterparty shall provide GS&Co. with written notice specifying (i) Counterparty's average daily Rule 10b-18 Purchases (as defined in Rule 10b-18) during the three full calendar months immediately preceding the Announcement Date that were not effected through GS&Co. or its affiliates and (ii) the number of Shares purchased pursuant to the proviso in Rule 10b-18(b)(4) under the Exchange Act for the three full calendar months preceding the Announcement Date. Such written notice shall be deemed to be a certification by Counterparty to GS&Co. that such information is true and correct. Counterparty understands that GS&Co. will use this information in calculating the trading volume for purposes of Rule 10b-18; and

(b) GS&Co. in its sole discretion may (i) make adjustments to the terms of any Transaction, including, without limitation, the Valuation Date and the Number of Shares to account for the number of Shares that could be purchased on each day during the Valuation Period in compliance with Rule 10b-18 following the Announcement Date or (ii) treat the occurrence of the Announcement Date as an Additional Termination Event with Counterparty as the sole Affected Party.

"Merger Transaction" means any merger, acquisition or similar transaction involving a recapitalization as contemplated by Rule 10b-18(a)(13)(iv) under the Exchange Act.

10. Special Settlement Following Early Termination and Extraordinary Events. Notwithstanding anything to the contrary in this Master Confirmation or any Supplemental Confirmation hereunder, in the event that an Extraordinary Event under Article 12 of the Equity Definitions occurs or an Early Termination Date under Section 6 of the Agreement occurs or is designated with respect to any Transaction (each an "Affected Transaction"), then either party may elect, by notice to the other party, to have Counterparty deliver the Number of Early Settlement Shares to GS&Co. on the date that such notice is effective (provided that GS&Co. determines in its good faith sole discretion that such delivery is in compliance with any legal, regulatory or self-regulatory requirements or related policies and procedures), except for a termination as a result of Section 7(d), in which event the date of delivery shall be the tenth Business Day thereafter. To the extent that Counterparty elects to deliver Shares to GS&Co. accompanied by an effective Registration Statement (satisfactory to GS&Co. in its reasonable discretion) covering such Early Settlement Shares, Counterparty must be in compliance with the conditions specified in (iii) though (ix) in Annex B hereto at the time of such delivery. If Counterparty elects to deliver Unregistered Shares (as defined in Annex B) to GS&Co., Counterparty and GS&Co. will negotiate in good faith on acceptable procedures and documentation relating to the sale of such Unregistered Shares.

"Number of Early Settlement Shares" means a number of Shares based on the Hedge Positions of GS&Co. or any of its Affiliates' with respect to each Affected Transaction under this Master Confirmation at the time of the Extraordinary Event or Early Termination Date, as applicable.

In determining the amount of Loss under Section 6(e) of the Agreement or the Cancellation Amount under Article 12, the parties shall take into account the Floating Rate Amount that would have otherwise been due to the Counterparty and the Fixed Amount that would have otherwise been due to GS&Co., and the difference between the New York 10b-18 Volume Weighted Average Price per share of the Shares over the Valuation Period as compared to the Forward Price. Further, if Counterparty delivers Early Settlement Shares, an amount equal to the product of (i) the Number of Early Settlement Shares multiplied by (ii) the Forward Price (or if Counterparty delivers Unregistered Shares, as reduced by a discount determined by GS&Co. in a good faith commercially reasonable manner based on the discount to the New York 10b-18 Volume Weighted Average Price at which it could sell the Shares and whether GS&Co. and Counterparty have agreed on acceptable procedures and documentation relating to such Unregistered Shares as described above) shall be credited against any amount owing under Section 6(e) of the Agreement or pursuant to Article 12 of the Equity Definitions or otherwise under this Master Confirmation.

11. Acknowledgments. The parties hereto intend for:

(a) Each Transaction to be a "securities contract" as defined in Section 741(7) of the U.S. Bankruptcy Code (Title 11 of the United States Code) (the "Bankruptcy Code"), a "swap agreement" as defined in Section 101(53B) of the Bankruptcy Code, or a "forward contract" as defined in Section 101(25) of the Bankruptcy Code, and the parties hereto to be entitled to the protections afforded by, among other Sections, Sections 362(b)(6), 362(b)(17), 555, 556, and 560 of the Bankruptcy Code;

(b) A party's right to liquidate or terminate any Transaction, net out or offset termination values of payment amounts, and to exercise any other remedies upon the occurrence of any Event of Default under the Agreement with respect to

the other party to constitute a "contractual right" (as defined in the Bankruptcy Code);

(c) All payments for, under or in connection with each Transaction, all payments for the Shares and the transfer of such Shares to constitute "settlement payments" and "transfers" (as defined in the Bankruptcy Code).

12. Set-Off. The parties agree to amend Section 6 of the Agreement by adding a new Section 6(f) thereto as follows:

"(f) Upon the occurrence of an Event of Default or Termination Event with respect to a party who is the Defaulting Party or the Affected Party ("X"), the other party ("Y") will have the right (but not be obliged) without prior notice to X or any other person to set-off or apply any obligation of X owed to Y (whether or not matured or contingent and whether or not arising under the Agreement, and regardless of the currency, place of payment or booking office of the obligation) against any obligation of Y owed to X (whether or not matured or contingent and whether or not arising under the Agreement, and regardless of the currency, place of payment or booking office of the obligation). Y will give notice to the other party of any set-off effected under this Section 6(f).

Amounts (or the relevant portion of such amounts) subject to set-off may be converted by Y into the Termination Currency at the rate of exchange at which such party would be able, acting in a reasonable manner and in good faith, to purchase the relevant amount of such currency. If any obligation is unascertained, Y may in good faith estimate that obligation and set-off in respect of the estimate, subject to the relevant party accounting to the other when the obligation is ascertained. Nothing in this Section 6 (f) shall be effective to create a charge or other security interest. This Section 6(f) shall be without prejudice and in addition to any right of set-off, combination of accounts, lien or other right to which any party is at any time otherwise entitled (whether by operation of law, contract or otherwise)."

13. Payment Date Upon Early Termination. Notwithstanding anything to the contrary in Section 6(d)(ii) of the Agreement, all amounts calculated as being due in respect of an Early Termination Date under Section 6(e) of the Agreement will be payable on the day that notice of the amount payable is effective, except as otherwise provided in this Master Confirmation or any Supplemental Confirmation.

14. Share Settlement; Maximum Shares. Notwithstanding anything contained in this Master Confirmation, the Agreement or the Equity Definitions, Counterparty may satisfy all amounts it may owe GS&Co. hereunder and under each Supplemental Confirmation by delivery of Shares in accordance with Annex B and/or Section 10 hereof, and is solely vested with the right to determine whether to satisfy its obligations in Shares, in cash or in a combination of the two. Notwithstanding anything contained in this Master Confirmation, the Agreement or the Equity Definitions, Counterparty and GS&Co. agree that if Counterparty elects to satisfy its obligations to GS&Co. by delivery of Shares, the delivery of a number of Shares equal to the Reserved Shares will satisfy in full the obligation of Counterparty to make any payments pursuant to Section 6(e) of the Agreement, Article 12 of the Equity Definitions or otherwise in respect of the Transaction.

15. Governing Law. The Agreement, this Master Confirmation and each Supplemental Confirmation and all matters arising in connection with the Agreement, this Master Confirmation and each Supplemental Confirmation shall be governed by, and construed and enforced in accordance with, the law of the State of New York without reference to its choice of law doctrine.

16. Offices.

(a) The Office of GS&Co. for each Transaction is: One New York Plaza, New York, New York 10004.

(b) The Office of Counterparty for each Transaction is: One Market Street Tower, Suite 2400 San Francisco, CA 94105.

17. Arbitration.

(a) **Arbitration is final and binding on Counterparty and GS&Co.**

(b) **Counterparty and GS&Co. are waiving their right to seek remedies in court, including the right to a jury trial.**

(c) **Pre-arbitration discovery is generally more limited than and different from court proceedings.**

(d) **The arbitrators' award is not required to include factual findings or legal reasoning and any party's right to appeal or to seek modification of rulings by the arbitrators is strictly limited.**

(e) **The panel of arbitrators will typically include a minority of arbitrators who were or are affiliated with the securities industry.**

Any controversy between or among GS&Co. or its affiliates, or any of its or their partners, directors, agents or employees, on the one hand, and Counterparty or its agents and affiliates, on the other hand, arising out of or relating to the

Agreement or any Transaction entered into hereunder, shall be settled by arbitration, in accordance with the then current rules of the American Arbitration Association ("AAA"), except that the provisions of this Section 17 shall supersede any conflicting or inconsistent provisions of such rules. Each party shall appoint a qualified arbitrator within 5 days after the giving of notice by either party. If either party shall fail timely to appoint a qualified arbitrator, the appointed, qualified arbitrator shall select the second qualified arbitrator within 5 days after such party's failure to appoint. The qualified arbitrators so appointed shall meet and shall, if possible, determine such matter within 10 days after the second qualified arbitrator is appointed, and their determination shall be binding on the parties. If for any reason such two qualified arbitrators fail to agree on such matter within such period of 10 days, then either party may request the AAA to appoint a qualified arbitrator who shall be impartial within 7 days of such request and both parties shall be bound by any appointment so made by the AAA. Within 7 days after the third qualified arbitrator has been appointed, each of the first two qualified arbitrators shall submit their respective determinations to the third qualified arbitrator who must select one or the other of such determinations (whichever the third qualified arbitrator believes to be correct or closest to a correct determination) within 7 days after the first two qualified arbitrators shall have submitted their respective determinations to the third qualified arbitrator, and the selection so made shall in all cases be binding upon the parties, and judgment upon such decision may be entered into any court having jurisdiction. In the event of the failure, refusal or inability of a qualified arbitrator to act, a successor shall be appointed within 10 days as hereinbefore provided. The costs of the arbitration shall be funded 50% by each party, and the parties shall bear their own attorneys' fees, during the arbitration. The prevailing party shall be repaid all of such expenses by the non-prevailing party within 10 days after the final determination of the qualified arbitrator(s). The award of the arbitrators shall be final, and judgment upon the award rendered may be entered in any court, state or Federal, having jurisdiction.

Neither party shall bring a putative or certified class action to arbitration, nor seek to enforce any pre-dispute arbitration agreement against any person who has initiated in court a putative class action; who is a member of a putative class who has not opted out of the class with respect to any claims encompassed by the putative class action until:

- (i) the class certification is denied;
- (ii) the class is decertified; or
- (iii) the party is excluded from the class by the court.

Such forbearance to enforce an agreement to arbitrate shall not constitute a waiver of any rights under the Agreement except to the extent stated herein.

[SIGNATURE PAGE FOLLOWS]

18. Counterparty hereby agrees (a) to check this Master Confirmation carefully and immediately upon receipt so that errors or discrepancies can be promptly identified and rectified and (b) to confirm that the foregoing (in the exact form provided by GS&Co.) correctly sets forth the terms of the agreement between GS&Co. and Counterparty with respect to any Transaction, by manually signing this Master Confirmation or this page hereof as evidence of agreement to such terms and providing the other information requested herein and immediately returning an executed copy to Equity Derivatives Documentation Department, facsimile No. 212-428-1980/83.

Yours sincerely,

GOLDMAN, SACHS & CO.

By: Frank Huber
Vice President
Authorized Signatory

Agreed and Accepted By:

PG&E CORPORATION

By: _____
Name:
Title:

ANNEX A

SUPPLEMENTAL CONFIRMATION FOR FULLY UNCOLLARED TRANSACTIONS

To: PG&E Corporation
One Market Spear Tower
Suite 2400
San Francisco, CA 94105

From: Goldman, Sachs & Co.

Subject: Accelerated Share Repurchase Transaction -
VWAP Pricing

Ref. No: EN50SH000000000

Date: June 16, 2005

The purpose of this Supplemental Confirmation is to confirm the terms and conditions of the Transaction entered into between Goldman, Sachs & Co. ("GS&Co.") and PG&E Corporation ("Counterparty") (together, the "Contracting Parties") on the Trade Date specified below. This Supplemental Confirmation is a binding contract between GS&Co. and Counterparty as of the relevant Trade Date for the Transaction referenced below.

1. This Supplemental Confirmation supplements, forms part of, and is subject to the Master Confirmation dated as of March 4, 2005 (the "Master Confirmation") between the Contracting Parties, as amended and supplemented from time to time. The definitions and provisions contained in the Master Confirmation are incorporated into this Supplemental Confirmation, except as expressly modified below. In the event of any inconsistency between those definitions and provisions and this Supplemental Confirmation, this Supplemental Confirmation will govern.

2. The terms of the Transaction to which this Supplemental Confirmation relates are as follows:

Trade Date:	June 27, 2005
Forward Price:	USD 35.60 per Share
Number of Shares:	11,430,000 Shares
Valuation Period Start Date:	June 28, 2005
Valuation Date:	September 7, 2005
Termination Price:	\$10 per Share
Fixed Rate:	25 basis points
Reserved Shares:	Two times the Number of Shares
Extraordinary Dividends:	Any cash dividend declared by the Issuer in excess of \$0.00 per Share except for the dividend in the amount of \$0.30 per Share payable on July 15, 2005
Initial Number of Daily Reference Shares:	228,600 Shares
Initial Notional Amount:	The Number of Shares multiplied by the Forward Price.
Counterparty Additional Payment Amount:	USD 3,429,000.00

In connection with this Transaction, clause (iv) of paragraph 3 of the Master Confirmation is hereby amended to read in full as follows: "(iv) the election that the "Cross Default" provisions of Section 5(a)(vi) shall apply to Counterparty, with a "Threshold Amount" of USD 100 million, and".

[SIGNATURE PAGE FOLLOWS]

3. Counterparty represents and warrants to GS&Co. that neither it (nor any "affiliated purchaser" as defined in Rule 10b-18 under the Exchange Act) have made any purchases of blocks except through GS&Co. or an entity affiliated with GS&Co. pursuant to the proviso in Rule 10b-18(b)(4) under the Exchange Act during the four full calendar weeks immediately preceding the Trade Date.

Counterparty hereby agrees (a) to check this Supplemental Confirmation carefully and immediately upon receipt so that errors or discrepancies can be promptly identified and rectified and (b) to confirm that the foregoing (in the exact form provided by GS&Co.) correctly sets forth the terms of the agreement between GS&Co. and Counterparty with respect to this Transaction, by manually signing this Supplemental Confirmation or this page hereof as evidence of agreement to such terms and providing the other information requested herein and immediately returning an executed copy to Equity Derivatives Documentation Department, facsimile No. 212-428-1980/83.

Yours sincerely,
GOLDMAN, SACHS & CO.

By: Sharon Siebold
Authorized Signatory

Agreed and Accepted
By: **PG&E CORPORATION**

By: Leroy T. Barnes
Name: Leroy T. Barnes
Title: Vice President and Treasurer

ANNEX B

NET SHARE SETTLEMENT PROCEDURES

The following Net Share Settlement Procedures shall apply to the extent that Counterparty elects Net Share Settlement in accordance with the Master Confirmation:

Net Share Settlement shall be made by delivery of the number of Shares equal in value to the sum of the Forward Cash Settlement Amount, the Fixed Amount and the Counterparty Additional Payment Amount (the "Settlement Shares"), with such Shares' value based on the Net Share Settlement Price. Delivery of such Settlement Shares shall be made free of any contractual or other restrictions in good transferable form (other than under the Securities Act with respect to any Unregistered Shares (as defined below)) on the Net Share Settlement Date with Counterparty (i) representing and warranting to GS&Co. at the time of such delivery that it has good, valid and marketable title or right to sell and transfer all such Shares to GS&Co. under the terms of the related Transaction free of any lien charge, claim or other encumbrance and (ii) making the representations and agreements contained in Section 9.11(ii) through (iv) of the Equity Definitions to GS&Co. with respect to the Settlement Shares. GS&Co. or any affiliate of GS&Co. designated by GS&Co. (GS&Co. or such affiliate, "GS") shall resell the Settlement Shares during a period (the "Resale Period") commencing no earlier than the Exchange Business Day on which the Settlement Shares are delivered. GS shall use its good faith, commercially reasonable efforts to sell the Settlement Shares as promptly as possible at commercially reasonable prices based on prevailing market prices for the Shares. The Resale Period shall end on the Exchange Business Day on which GS completes the sale of all Settlement Shares or a sufficient number of Settlement Shares so that the realized net proceeds of such sales exceed the sum of Forward Cash Settlement Amount, the Fixed Amount and the Counterparty Additional Payment Amount. Notwithstanding the foregoing, if resale by GS of the Settlement Shares, as determined by GS in its sole discretion (i) occurs during a distribution for purposes of Regulation M, and if GS would be subject to the restrictions of Rule 101 of Regulation M in connection with such distribution, the Resale

Period will be postponed or tolled, as the case may be, until the Exchange Business Day immediately following the end of any "restricted period" as such term is defined in Regulation M with respect to such distribution under Regulation M or (ii) conflict with any legal, regulatory or self-regulatory requirements or related policies and procedures applicable to GS (whether or not such requirements, policies or procedures are imposed by law or have been voluntarily adopted by GS), the Resale Period will be postponed or tolled, as the case may be, until such conflict is no longer applicable. During the Resale Period, if the realized net proceeds from the resale of the Settlement Shares exceed the sum of the Forward Cash Settlement Amount, the Fixed Amount and the Counterparty Additional Payment Amount, GS shall refund such excess in cash to Counterparty by the close of business on the third Exchange Business Day immediately following the last day of the Resale Period. If the sum of the Forward Cash Settlement Amount, the Fixed Amount and the Counterparty Additional Payment Amount exceeds the realized net proceeds from such resale, Counterparty shall transfer to GS by the open of the regular trading session on the Exchange on the third Scheduled Trading Day immediately following the last day of the Resale Period the amount of such excess (the "Additional Amount") in the number of Shares ("Make-whole Shares") in an amount that, based on the Net Share Settlement Price on the last day of the Resale Period (as if such day was the "Net Share Valuation Date" for purposes of computing such Net Share Settlement Price), has a dollar value equal to the Additional Amount. The Resale Period shall continue to enable the sale of the Make-whole Shares. The requirements and provisions set forth below shall apply to Shares delivered to pay such Additional Amounts. This provision shall be applied successively until the Additional Amount is equal to zero.

Net Share Settlement of a Transaction is subject to the following conditions:

Counterparty at its sole expense shall:

(i) as promptly as practicable (but in no event more than five (5) Exchange Business Days immediately following the Settlement Method Election Date or, in the case of an election of Net Share Settlement upon the occurrence of an Extraordinary Event or an Early Termination Date, no more than one Exchange Business Day immediately following either the Cancellation Date or the Early Termination Date, as the case may be) file under the Securities Act and use its best efforts to make effective, as promptly as practicable, a registration statement or supplement or amend an outstanding registration statement, in any such case, in form and substance reasonably satisfactory to GS (the "Registration Statement") covering the offering and sale by GS of not less than 150% of the Shares necessary to fulfill the Net Share Settlement delivery obligation by Counterparty (determining the number of such Shares to be registered on the basis of the average of the Settlement Prices on the five (5) Exchange Business Days prior to the date of such filing, amendment or supplement, as the case may be);

(ii) maintain the effectiveness of the Registration Statement until GS has sold all shares to be delivered by Counterparty necessary to satisfy its Net Share Settlement obligations;

(iii) have afforded GS and its counsel and other advisers a reasonable opportunity to conduct a due diligence investigation of Counterparty customary in scope for transactions in which GS acts as underwriter of equity securities, and GS shall have been satisfied (with the approval of its Commitments Committee in accordance with its customary review process) with the results of such investigation;

(iv) have negotiated and entered into an agreement with GS providing for such covenants, conditions, representations and warranties, underwriting discounts, commissions, indemnities and contribution rights as are customary for GS equity underwriting agreements, together with customary certificates and opinions of counsel and letters of independent auditors of Counterparty to be delivered to GS covering the shares to be delivered by Counterparty in satisfaction of its Net Share Settlement obligations;

(v) have delivered to GS such number of prospectuses relating thereto as GS shall have reasonably requested and shall promptly update and provide GS with replacement prospectuses as necessary to ensure the prospectus does not contain any untrue statement of a material fact or any omission of a material fact required to be stated therein or necessary to make the statements therein, in the light of the circumstances in which they were made, not misleading;

(vi) have retained for GS nationally-recognized underwriting counsel acceptable to GS (in its sole discretion) with broad experience in similar registered securities offerings and such counsel shall have agreed to act as such;

(vii) have taken all steps necessary for the shares sold by GS to be listed or quoted on the primary exchange or quotation system that the Shares are listed or quoted on;

(viii) have paid all reasonable and actual out-of-pocket costs and expenses of GS and all reasonable and actual fees and expenses of GS's outside counsel and other independent experts in connection with the foregoing; and

(ix) take such action as is required to ensure that GS's sale of the Shares does not violate, or result in a violation of, the federal or state securities laws.

In the event that the Registration Statement is not declared effective by the Securities Exchange Commission (the "SEC") or any of the conditions specified in (ii) through (ix) above are not satisfied on or prior to the Valuation Date (or, in the case of an election of Net Share Settlement upon the occurrence of an Extraordinary Event or an Early Termination Date, on or

prior to the first Exchange Business Day following either the Cancellation Date or the Early Termination Date, as the case may be except for any Early Termination as result of Section 7(d) of the Master Confirmation, in which case, such date shall be the tenth Exchange Business Day following such Early Termination Date), then Counterparty may deliver Unregistered Shares to GS in accordance with the following conditions. If GS and Counterparty can agree on acceptable pricing, procedures and documentation relating to the sale of such Unregistered Shares (including, without limitation, applicable requirements in (iii) through (ix) above and insofar as pertaining to private offerings), then such Unregistered Shares shall be deemed to be the "Settlement Shares" for the purposes of the related Transaction and the settlement procedure specified in this Annex B shall be followed except that in the event that the Forward Cash Settlement Amount plus the Fixed Amount, exceeds the proceeds from the sale of such Unregistered Shares then for the purpose of calculating the number of "Make-whole Shares" to be delivered by Counterparty, GS shall determine the discount to the Net Share Settlement Price at which it can sell the Unregistered Shares. Notwithstanding the delivery of the Unregistered Shares, Counterparty shall endeavor in good faith to have a registration statement declared effective by the SEC as soon as practical. In the event that GS has not sold sufficient Unregistered Shares to satisfy Counterparty's obligations to GS contained herein at the time that a Registration Statement covering the offering and sale by GS of a number of Shares equal in value to not less than 150% of the amount then owed to GS is declared effective (based on the Net Share Settlement Price on the Exchange Business Day (as if such Exchange Business Day were the "Net Share Valuation Date" for purposes of computing such Net Share Settlement Price) that the Registration Statement was declared effective), GS shall return all unsold Unregistered Shares to Counterparty and Counterparty shall deliver such number of Shares covered by the effective Registration Statement equal to 100% of the amount then owed to GS based on such Net Share Settlement Price. Such delivered shares shall be deemed to be the "Settlement Shares" for the purposes of the related Transaction and the settlement procedure specified in this Master Confirmation, including, without limitation, this Annex B, (including the obligation to deliver any Make-whole Shares, if applicable) shall be followed. In all cases GS shall be entitled to take any and all required actions in the course of its sales of the Settlement Shares, including without limitation making sales of the Unregistered Shares only to "Qualified Institutional Buyers" (as such term is defined under the Securities Act), to ensure that the sales of the Unregistered Shares and the Settlement Shares covered by the Registration Statement are not integrated resulting in a violation of the securities laws and Counterparty agrees to take all actions requested by GS in furtherance thereof.

If GS and Counterparty cannot agree on acceptable pricing, procedures and documentation relating to the sales of such Unregistered Shares then the number of Unregistered Shares to be delivered to GS pursuant to the provisions above shall not be based on the Net Share Settlement Price but rather GS shall determine the value attributed to each Unregistered Share in a commercially reasonable manner and based on such value Counterparty shall deliver a number of Shares equal in value to the Forward Cash Settlement Amount plus the Fixed Amount. For the purposes hereof "Unregistered Shares" means Shares that have not been registered pursuant to an effective registration statement under the Securities Act or any state securities laws ("Blue Sky Laws") and that cannot be sold, transferred, pledged or otherwise disposed of without registration under the Securities Act or under applicable Blue Sky Laws unless such sale, transfer, pledge or other disposition is made in a transaction exempt from registration thereunder.

In the event that Counterparty delivers Shares pursuant to an election of Net Share Settlement then Counterparty agrees to indemnify and hold harmless GS, its affiliates and its assignees and their respective directors, officers, employees, agents and controlling persons (GS and each such person being an "Indemnified Party") from and against any and all losses, claims, damages and liabilities (or actions in respect thereof), joint or several, to which such Indemnified Party may become subject, under the Securities Act or otherwise, (i) relating to or arising out of any of the Transactions contemplated by this Master Confirmation concerning Net Share Settlement or (ii) arising out of or based upon any untrue statement or alleged untrue statement of a material fact contained in any preliminary prospectus, prospectus, Registration Statement or other written material relating to the Shares delivered to prospective purchasers, including in each case any amendments or supplements thereto and including but not limited to any documents deemed to be incorporated in any such document by reference (the "Offering Materials"), or arising out of or based upon any omission or alleged omission to state in the Offering Materials a material fact necessary in order to make the statements therein, in the light of the circumstances under which they were made, not misleading; provided, however, that, in the case of this clause (ii), Counterparty will not be liable to the extent that any loss, claim, damage or liability arises out of or is based upon any untrue statement or omission or alleged untrue statement or omission in the Offering Materials made in reliance upon and in conformity with written information furnished to Counterparty by GS expressly for use in the Offering Materials, as expressly identified in a letter to be delivered at the closing of the delivery of Shares by Counterparty to GS. The foregoing indemnity shall exclude losses that GS incurs solely by reason of the proceeds from the sale of the Capped Number of Shares being less than the Forward Cash Settlement Amount. Counterparty will not be liable under the foregoing indemnification provision to the extent that any loss, claim, damage, liability or expense is found in a nonappealable judgment by a court of competent jurisdiction to have resulted from GS's willful misconduct, gross negligence or bad faith in performing the services that are subject of this Master Confirmation or from information provided in writing by GS for inclusion in the Registration Statement. If for any reason the foregoing indemnification is unavailable to any Indemnified Party or insufficient to hold harmless any Indemnified Party, then Counterparty shall contribute, to the maximum extent permitted by law, to the amount paid or payable by the Indemnified Party as a result of such loss, claim, damage or liability. In addition, Counterparty will reimburse any Indemnified Party for all expenses (including reasonable counsel fees and expenses) as they are incurred (after notice to Counterparty) in connection with the investigation of, preparation for or defense or settlement of any pending or threatened claim or any action, suit or proceeding arising therefrom, whether or not such Indemnified Party is a party thereto and whether or not such claim, action, suit or proceeding is initiated or brought by or on behalf of Counterparty. Counterparty also agrees that no Indemnified Party shall have any liability to Counterparty or any person asserting claims on behalf of or in right of Counterparty in connection with or as a result of any matter referred to in the Agreement or this Master Confirmation concerning Net Share Settlement except to the extent that any losses, claims, damages, liabilities or expenses incurred by Counterparty result from the gross negligence, willful misconduct or bad faith of the Indemnified Party. This

indemnity shall survive the completion of any Transaction contemplated by this Master Confirmation and any assignment and delegation of a Transaction made pursuant to this Master Confirmation or the Agreement shall inure to the benefit of any permitted assignee of GS&Co.

In no event shall the number of Settlement Shares (including, but without duplication or double counting, any Unregistered Shares) and any Make-whole Shares, be greater than the Reserved Shares minus the amount of any Shares actually delivered under any other Transaction(s) under this Master Confirmation (the result of such calculation, the "Capped Number"). Counterparty represents and warrants (which shall be deemed to be repeated on each day that a Transaction is outstanding) that the Capped Number is equal to or less than the number of Shares determined according to the following formula:

$$A - B$$

Where A = the number of authorized but unissued shares of the Issuer that are not reserved for future issuance on the date of the determination of the Capped Number; and

B = the maximum number of Shares required to be delivered to third parties if Counterparty elected Net Share Settlement of all transactions in the Shares (other than Transactions in the Shares under this Master Confirmation) with all third parties that are then currently outstanding and unexercised.

SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN
OF
PG&E CORPORATION
(As Amended Effective as of June 15, 2005)

This is the controlling and definitive statement of the Supplemental Executive Retirement Plan ("PLAN") ^{1/} for ELIGIBLE EMPLOYEES of PG&E Corporation ("CORPORATION"), Pacific Gas and Electric Company ("COMPANY") and such other companies, affiliates, subsidiaries, or associations as the BOARD OF DIRECTORS may designate from time to time. The PLAN is the successor plan to the Supplemental Executive Retirement Plan of the COMPANY. The PLAN as contained herein was first adopted effective January 1, 2005.

ARTICLE I

DEFINITIONS

1.01 Basic SERP Benefit shall mean the benefit described in Section 2.01.

1.02 Board or Board of Directors shall mean the BOARD OF DIRECTORS of the CORPORATION or, when appropriate, any committee of the BOARD which has been delegated the authority to take action with respect to the PLAN.

1.03 Company shall mean the Pacific Gas and Electric Company, a California corporation.

1.04 Corporation shall mean PG&E Corporation, a California corporation.

1.05 Eligible Employee shall mean (1) employees of the COMPANY (or, with respect to the CORPORATION and PG&E Corporation Support Services, Inc., employees who were transferred to the CORPORATION or PG&E Corporation Support Services, Inc., from the COMPANY), (2) who are officers in Officer Bands I-V, and (3) such other employees of the COMPANY, the CORPORATION, PG&E Corporation Support Services, Inc. or such other companies, affiliates, subsidiaries, or associations, as may be designated by the Chief Executive Officer of the CORPORATION. ELIGIBLE EMPLOYEES shall not include employees who retired prior to January 1, 2005, or whose employment relationship with any of the PARTICIPATING EMPLOYERS was otherwise terminated prior to January 1, 2005.

1.06 STIP Payment shall mean amounts received by an ELIGIBLE EMPLOYEE under the Short-Term Incentive Plan maintained by the CORPORATION.

^{1/} Words in all capitals are defined in Article I.

1.07 Participating Employer shall mean the COMPANY, the CORPORATION, PG&E Corporation Support Services, Inc., and any other companies, affiliates, subsidiaries or associations designated by the Chief Executive Officer of the CORPORATION.

1.08 Plan shall mean the Supplemental Executive Retirement Plan ("SERP") as set forth herein and as may be amended from time to time.

1.09 Plan Administrator shall mean the Employee Benefit Committee or such individual or individuals as that Committee may appoint to handle the day-to-day affairs of the PLAN.

1.10 Retirement Plan shall mean the Pacific Gas and Electric Company Retirement Plan for Management Employees.

1.11 Salary shall mean the base salary received by an ELIGIBLE EMPLOYEE. SALARY shall not include amounts received by an employee after such employee ceases to be an ELIGIBLE EMPLOYEE. For purposes of calculating benefits under the PLAN, SALARY shall not be reduced to reflect amounts that have been deferred under the PG&E Corporation Supplemental Retirement Savings Plan.

1.12 Service shall mean "credited service" as that term is defined in the RETIREMENT PLAN or, if the Nominating and Compensation Committee of the BOARD OF DIRECTORS has granted an adjusted service date for an ELIGIBLE EMPLOYEE, "credited service" as calculated from such adjusted service date. In no event, however, shall SERVICE include periods of time after which an officer has ceased to be an ELIGIBLE EMPLOYEE.

ARTICLE II

SERP BENEFITS

2.01 The BASIC SERP BENEFIT payable from the PLAN shall be a monthly annuity commencing on the later of the first of the seventh (7th) month following the month in which the ELIGIBLE EMPLOYEE ceases to be an employee of the PARTICIPATING EMPLOYER or the first of the month following the ELIGIBLE EMPLOYEE's 55th birthday. The monthly amount of the BASIC SERP BENEFIT shall be equal to the product of:

$1.7\% \times \text{the average of three highest calendar years' combination of SALARY and STIP PAYMENT for the last ten years of SERVICE}$
 $\times \text{SERVICE} \times 1/12.$

In computing a year's combination of SALARY and STIP PAYMENT, the year's amount shall be the sum of the SALARY and STIP PAYMENT, if any, paid or payable in the same calendar year. If an ELIGIBLE EMPLOYEE has fewer than three years' SALARY, the average shall be the combination of SALARY and STIP PAYMENT for such shorter time, divided by the number of years and partial years during which such employee was an ELIGIBLE EMPLOYEE.

The BASIC SERP BENEFIT is further reduced by any amounts paid or payable from the RETIREMENT PLAN, calculated before adjustments for marital or joint pension option elections.

2.02 For ELIGIBLE EMPLOYEES of the PARTICIPATING EMPLOYERS, who transfer from any of said companies to another subsidiary or affiliate, the principles of Section 10 of the RETIREMENT PLAN shall govern the calculation of benefits under this PLAN. An ELIGIBLE EMPLOYEE who ceases to be an employee of a PARTICIPATING EMPLOYER and who is also not employed by any of the CORPORATION's subsidiaries, affiliates, or related associations shall be entitled to receive a benefit payable from the PLAN at any time after his 55th birthday. The amount of the benefit payable shall be reduced by the appropriate age and service factors contained in the RETIREMENT PLAN applicable to such employee. For such calculations, the service factor shall be SERVICE as defined in the PLAN.

In computing amounts payable from the RETIREMENT PLAN as an offset to the benefit payable from this PLAN, the RETIREMENT PLAN benefit shall be calculated as though the ELIGIBLE EMPLOYEE elected to receive a pension from the RETIREMENT PLAN commencing on the same date as benefits from this PLAN.

2.03 An ELIGIBLE EMPLOYEE may elect to have his BASIC SERP BENEFIT paid in any one of the following forms:

a. BASIC SERP BENEFIT, or a reduced BASIC SERP BENEFIT as calculated under Section 2.02, paid as a monthly annuity for the life of the ELIGIBLE EMPLOYEE with no survivor's benefit.

b. A monthly annuity payable for the life of the ELIGIBLE EMPLOYEE with a survivor's option payable to the ELIGIBLE EMPLOYEE's joint annuitant beginning on the first of the month following the ELIGIBLE EMPLOYEE'S death. The factors to be applied to reduce the BASIC SERP BENEFIT to provide for a survivor's benefit shall be the factors which are contained in the RETIREMENT PLAN and which are appropriate given the type of joint pension elected and the ages and marital status of the joint annuitants.

2.04 Annuities payable to an ELIGIBLE EMPLOYEE who is receiving a (i) BASIC SERP BENEFIT, (ii) a BASIC SERP BENEFIT reduced to provide a survivor's benefit to a joint annuitant, or (iii) a joint annuitant who is receiving a survivor's benefit shall be decreased by any additional amounts which can be paid from the RETIREMENT PLAN where such additional amounts are due to increases in the limits placed on benefits payable from qualified pension plans under Section 415 of the Internal Revenue Code. The amount of any such decrease shall be adjusted to reflect the type of pension elected by an ELIGIBLE EMPLOYEE under the RETIREMENT PLAN and this PLAN.

ARTICLE III

DEATH BENEFITS

3.01 In the event that an ELIGIBLE EMPLOYEE who has accrued a benefit under this PLAN dies prior to the date that a BASIC SERP BENEFIT would otherwise commence and the ELIGIBLE EMPLOYEE is married at the time of the ELIGIBLE EMPLOYEE's death, the PLAN ADMINISTRATOR shall pay a spouse's benefit to the ELIGIBLE EMPLOYEE's surviving spouse:

a. If the sum of the age and SERVICE of the ELIGIBLE EMPLOYEE at the time of death equaled 70 (69.5 or more is rounded to 70) or if the ELIGIBLE EMPLOYEE was age 55 at the time of death, the spouse's benefit shall be a monthly annuity commencing on the first of the month following the month in which the ELIGIBLE EMPLOYEE dies and shall be payable for the life of the surviving spouse. The amount of the monthly benefit shall be one-half of the monthly BASIC SERP BENEFIT that would have been paid to the ELIGIBLE EMPLOYEE calculated:

1) as if he had elected to receive a BASIC SERP BENEFIT, without survivor's option;

2) the monthly annuity starting date was the first of the month following the month in which the ELIGIBLE EMPLOYEE died; and

3) without the application of early retirement reduction factors.

b. If the ELIGIBLE EMPLOYEE is less than 55 years of age or had fewer than 70 points (as calculated under Section 3.01(a)) at the time of death, the surviving spouse will be entitled to receive a monthly annuity commencing on the first of the month following the month in which the ELIGIBLE EMPLOYEE would have become age 55 if he had survived. The amount of the monthly annuity payable to the surviving spouse shall be equal to the BASIC SERP BENEFIT converted to a marital joint annuity providing for a 50 percent survivor's benefit, calculated as if: 1) the ELIGIBLE EMPLOYEE had terminated employment at the date of death, 2) had lived until age 55, 3) had begun to receive PENSION payments, and 4) had subsequently died.

c. If a former ELIGIBLE EMPLOYEE was age 55 or older at the time of his death and not yet receiving a SERP BENEFIT under the PLAN, the surviving spouse will be entitled to receive a monthly annuity in an amount equal to the BASIC SERP BENEFIT converted to a marital joint annuity providing for a 50 percent survivor's benefit, calculated as if the former ELIGIBLE EMPLOYEE had begun receiving the converted SERP BENEFIT immediately prior to his death.

d. If a former ELIGIBLE EMPLOYEE was younger than age 55 or had fewer than 70 points (as calculated under Section 3.01(a)) at the time of his death, the surviving spouse will be entitled to receive a monthly annuity in an amount equal to the BASIC SERP BENEFIT converted to a marital joint annuity providing for a 50 percent survivor's benefit, calculated as if: 1) the former ELIGIBLE EMPLOYEE had survived until age 55, 2) had begun receiving the converted SERP BENEFIT, and 3) had subsequently died.

3.02 A surviving spouse who is entitled to receive a spouse's benefit under Section 3.01 shall not be entitled to receive any other benefit under the PLAN.

ARTICLE IV

ADMINISTRATIVE PROVISIONS

4.01 Administration. The PLAN shall be administered by the Senior Human Resources Officer of the CORPORATION ("PLAN ADMINISTRATOR"), who shall have the authority to interpret the PLAN and make and revise such rules as he or she deems appropriate. The PLAN ADMINISTRATOR shall have the duty and responsibility of maintaining records, making the requisite calculations, and disbursing payments hereunder. The PLAN ADMINISTRATOR's interpretations, determinations, rules, and calculations shall be final and binding on all persons and parties concerned.

4.02 Amendment and Termination. The CORPORATION may amend or terminate the PLAN at any time, provided, however, that no such amendment or termination shall adversely affect an accrued benefit which an ELIGIBLE EMPLOYEE has earned prior to the date of such amendment or termination, nor shall any amendment or termination adversely affect a benefit which is being provided to an ELIGIBLE EMPLOYEE, surviving spouse, joint annuitant, or beneficiary under Article II or Article III on the date of such amendment or termination. Anything in this Section 4.02 to the contrary notwithstanding, the CORPORATION may reduce or terminate any benefit to which an ELIGIBLE EMPLOYEE, surviving spouse or joint annuitant, is or may become entitled provided that such ELIGIBLE EMPLOYEE, surviving spouse or joint annuitant is or becomes entitled to an amount equal to such benefit under another plan, practice, or arrangement of the CORPORATION.

4.03 Nonassignability of Benefits. Except to the extent otherwise directed by a domestic relations order that the Plan Administrator determines is a Qualified Domestic Relations Order under Section 401(a)(12) of the Internal Revenue Code, the benefits payable under this PLAN or the right to receive future benefits under this PLAN may not be anticipated, alienated, pledged, encumbered, or subject to any charge or legal process, and if any attempt is made to do so, or a person eligible for any benefits becomes bankrupt, the interest under the PLAN of the person affected may be terminated by the PLAN ADMINISTRATOR which, in its sole discretion, may cause the same to be held if applied for the benefit of one or more of the dependents of such person or make any other disposition of such benefits that it deems appropriate.

4.04 Nonguarantee of Employment. Nothing contained in this PLAN shall be construed as a contract of employment between a PARTICIPATING EMPLOYER and the ELIGIBLE EMPLOYEE, or as a right of the ELIGIBLE EMPLOYEE to be continued in the employ of a PARTICIPATING EMPLOYER, to remain as an officer of a PARTICIPATING EMPLOYER, or as a limitation on the right of a PARTICIPATING EMPLOYER to discharge any of its employees, with or without cause.

4.05 Apportionment of Costs. The costs of the PLAN may be equitably apportioned by the PLAN ADMINISTRATOR among the PARTICIPATING EMPLOYERS. Each PARTICIPATING EMPLOYER shall be responsible for making benefit payments pursuant to the PLAN on behalf of its ELIGIBLE EMPLOYEES or for reimbursing the CORPORATION for the cost of such payments, as determined by the CORPORATION in its sole discretion. In the event the respective PARTICIPATING EMPLOYER fails to make such payment or reimbursement, and the CORPORATION does not exercise its discretion to make the contribution on such PARTICIPATING EMPLOYER's behalf, future benefit accruals of the ELIGIBLE EMPLOYEES of that PARTICIPATING EMPLOYER shall be suspended. If at some future date, the PARTICIPATING EMPLOYER makes all past-due contributions, plus interest at a rate determined by the PLAN ADMINISTRATOR in his or her sole discretion, the benefit accrual of its ELIGIBLE EMPLOYEES will be recognized for the period of the

suspension.

4.06 Benefits Unfunded and Unsecured. The benefits under this PLAN are unfunded, and the interest under this PLAN of any ELIGIBLE EMPLOYEE and such ELIGIBLE EMPLOYEE's right to receive a distribution of benefits under this PLAN shall be an unsecured claim against the general assets of the CORPORATION.

4.07 Applicable Law. All questions pertaining to the construction, validity, and effect of the PLAN shall be determined in accordance with the laws of the United States, and to the extent not preempted by such laws, by the laws of the State of California.

4.08 Satisfaction of Claims. Notwithstanding Section 4.05 or any other provision of the PLAN, the CORPORATION may at any time satisfy its obligations (either on a before-tax or after-tax basis) for any benefits accrued under the PLAN by the purchase from an insurance company of an annuity contract on behalf of an ELIGIBLE EMPLOYEE. Such purchase shall be in the sole discretion of the CORPORATION and shall be subject to the ELIGIBLE EMPLOYEE'S acknowledgement that the CORPORATION's obligations to provide benefits hereunder have been discharged, without regard to the payments ultimately made under the contract. In the event of a purchase pursuant to this Section 4.07, the CORPORATION may in its sole discretion make payments to or on behalf of an ELIGIBLE EMPLOYEE to defray the cost to such ELIGIBLE EMPLOYEE of any personal income tax in connection with the purchase.

EXHIBIT 11

PG&E CORPORATION

COMPUTATION OF EARNINGS PER COMMON SHARE

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
(in millions, except share amounts)	2005	2004	2005	2004
Net income	\$ 267	\$ 372	\$ 485	\$ 3,405
Less: distributed earnings to common shareholders	112	-	223	-
Undistributed earnings	155	372	262	3,405
Common shareholders earnings				
<i>Basic</i>				
Distributed earnings to common shareholders	\$ 112	\$ -	\$ 223	\$ -
Undistributed earnings allocated to common shareholders	147	355	249	3,249
Total common shareholders earnings, basic	\$ 259	\$ 355	\$ 472	\$ 3,249
<i>Diluted</i>				
Distributed earnings to common shareholders	\$ 112	\$ -	\$ 223	\$ -
Undistributed earnings allocated to common shareholders	148	356	250	3,252
Total common shareholders earnings, diluted	\$ 260	\$ 356	\$ 473	\$ 3,252
Weighted average common shares outstanding, basic	370	397	379	395
9.50% Convertible Subordinated Notes	19	19	19	19
Weighted average common shares outstanding and participating securities, basic	389	416	398	414
Weighted average common shares outstanding, basic	370	397	379	395
Employee stock compensation, restricted stock, accelerated share repurchase agreement and PG&E Corporation shares held by grantor trusts	5	7	5	7
PG&E Corporation warrants	-	2	-	3
Rounding	(1)	-	(1)	-
Weighted average common shares outstanding, diluted ⁽¹⁾	374	406	383	405
9.50% Convertible Subordinated Notes	19	19	19	19

Weighted average common shares outstanding and participating securities, diluted	393	425	402	424
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Net earnings per common share, basic

Distributed earnings, basic	\$ 0.30	\$ -	\$ 0.59	\$ -
Undistributed earnings, basic	0.40	0.89	0.66	8.22
Total	\$ 0.70	\$ 0.89	\$ 1.25	\$ 8.22

Net earnings per common share, diluted

Distributed earnings, diluted	\$ 0.30	\$ -	\$ 0.58	\$ -
Undistributed earnings, diluted	0.40	0.88	0.65	8.03
Total	\$ 0.70	\$ 0.88	\$ 1.23	\$ 8.03

- (1) Options to purchase 6,500 PG&E Corporation common shares were outstanding during the three and six months ended June 30, 2005 and, 8,235,055 and 7,874,615 for the three and six months ended June 30, 2004, respectively, but not included in the computation of diluted earnings per common share because the option exercise prices were greater than the average market price.

Exhibit 12.1**Pacific Gas and Electric Company****Computation of Ratios of Earnings to Fixed Charges**

		Three Months Ended June 30,	Six Months Ended June 30,					Year Ended December 31,	
(dollars in millions)		2005	2005	2004	2003	2002	2001		2000
Earnings ⁽¹⁾									
	Pre-tax income (loss) from continuing operations	\$ 442	\$ 808	\$ 6,543	\$ 1,451	\$ 2,997	\$ 1,611		\$ (5,637)
Add:	Fixed Charges	132	294	671	964	1,029	1,019		648
Less:	Preferred dividend requirements of subsidiaries	-	-	-	-	-	-		-
	Total Earnings (Loss)	\$ 574	\$ 1,102	\$ 7,214	\$ 2,415	\$ 4,026	\$ 2,630		\$ (4,989)
Fixed Charges ⁽²⁾									
	Interest expense, net, including amortization of debt issue costs, premiums and discounts	\$ 124	\$ 279	\$ 668	\$ 939	\$ 990	\$ 976		\$ 609
	AFUDC Debt	4	7	(12)	16	21	12		6
	Estimate of interest expense within rents	4	8	15	9	8	7		9
	Preferred dividend requirements of subsidiaries	-	-	-	-	-	-		-
	Preferred security requirements of wholly-owned trust	-	-	-	-	10	24		24
	Total Fixed Charges	\$ 132	\$ 294	\$ 671	\$ 964	\$ 1,029	\$ 1,019		\$ 648
Ratio of Earnings (Loss) to Fixed Charges ⁽³⁾		4.35	3.75	10.75	2.51	3.91	2.58		(7.70)

(1) For purposes of computing the ratio of earnings to fixed charges, "earnings" represents pre-tax income from continuing operations adjusted for minority interest in consolidated subsidiaries and equity in income or loss from subsidiaries accounted for using the equity method plus fixed charges, as computed, less the pre-tax earnings required to cover the preferred dividend requirements of subsidiaries.

(2) "Fixed charges" include interest, including amortization of debt issue costs, premiums and discounts, the debt portion of the allowance for funds used during construction, an estimate of the amount of interest within rents, and the preferred security requirements of consolidated subsidiaries.

(3) The ratio of earnings to fixed charges for the year 2000 indicates a ratio of less than one-to-one. The dollar amount of the deficiency is approximately \$5.6 billion.

Exhibit 12.2**Pacific Gas and Electric Company****Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Dividends**

	Three Months Ended June 30,		Six Months Ended June 30,	Year Ended December 31,			
(dollars in millions)	2005	2005	2004	2003	2002	2001	2000
Earnings ⁽¹⁾							
Pre-tax income (loss) from continuing operations	\$ 442	\$ 808	\$ 6,543	\$ 1,451	\$ 2,997	\$ 1,611	\$ (5,637)
Add:							
Fixed Charges	132	294	671	964	1,029	1,019	648
Less:							
Preferred dividend requirements of subsidiaries	-	-	-	-	-	-	-
Total Earnings (Loss)	\$ 574	\$ 1,102	\$ 7,214	\$ 2,415	\$ 4,026	\$ 2,630	\$ (4,989)
Fixed Charges ⁽²⁾							
Interest expense, net, including amortization of debt issue costs, premiums and discounts	\$ 124	\$ 279	\$ 668	\$ 939	\$ 990	\$ 976	\$ 609
AFUDC Debt	4	7	(12)	16	21	12	6
Estimate of interest expense within rents	4	8	15	9	8	7	9
Preferred dividend requirements of subsidiaries	-	-	-	-	-	-	-
Preferred security requirements of wholly-owned trust	-	-	-	-	10	24	24
Total Fixed Charges	\$ 132	\$ 294	\$ 671	\$ 964	\$ 1,029	\$ 1,019	\$ 648
Preferred Stock Dividends							
Tax deductible dividends	\$ 3	\$ 6	\$ 9	\$ 9	\$ 9	\$ 9	\$ 9
Pre-tax earnings required to cover non-tax deductible preferred stock dividend requirements	5	11	34	27	28	27	27
Total Preferred Stock Dividends	\$ 8	\$ 17	\$ 43	\$ 36	\$ 37	\$ 36	\$ 36
Total Fixed Charges and Preferred Stock Dividends	\$ 140	\$ 311	\$ 714	\$ 1,000	\$ 1,066	\$ 1,055	\$ 684
Ratio of Earnings (Loss) to Combined Fixed Charges and Preferred Stock Dividends ⁽³⁾	4.10	3.54	10.10	2.42	3.78	2.49	(7.29)

(1) For purposes of computing the ratio of earnings to fixed charges, "earnings" represents pre-tax income from continuing operations adjusted for minority interest in consolidated subsidiaries and equity in income or loss from subsidiaries accounted for using the equity method plus fixed charges, as computed, less the pre-tax earnings required to cover the preferred dividend requirements of subsidiaries.

(2) "Fixed charges" include interest, including amortization of debt issue costs, premiums and discounts, the debt portion of the allowance for funds used during construction, an estimate of the amount of interest within rents, and the preferred security requirements of consolidated subsidiaries.

(3) The ratio of earnings to fixed charges for the year 2000 indicates a ratio of less than one-to-one. The dollar amount of the deficiency is approximately \$5.6 billion.

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

I, Peter A. Darbee, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarter ended June 30, 2005 of PG&E Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - A. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - B. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - C. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - D. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
 - A. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - B. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 3, 2005

Peter A. Darbee

Peter A. Darbee

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 June 30, 2005 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
1. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
 - A. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - B. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 3, 2005

Christopher P. Johns

Christopher P. Johns

Senior Vice President, Chief
Financial Officer and Controller

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

I, Gordon R. Smith, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarter ended June 30, 2005 of Pacific Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - A. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - B. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - C. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - D. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
 - A. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - B. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 3, 2005

Gordon R. Smith

Gordon R. Smith

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

I, Kent M. Harvey, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarter ended June 30, 2005 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
1. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
 - A. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - B. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 3, 2005

Kent M. Harvey

Kent M. Harvey

Senior Vice President, Chief
Financial Officer and Treasurer

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

In connection with the accompanying Quarterly Report on Form 10-Q of PG&E Corporation for the quarter ended June 30, 2005, I, Peter A. Darbee, President and Chief Executive Officer of PG&E Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

- (1) such Quarterly Report on Form 10-Q of PG&E Corporation for the quarter ended June 30, 2005, 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 June 30, 2005, fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

PETER A. DARBEE

PETER A. DARBEE.

President and Chief Executive Officer

August 3, 2005

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

In connection with the accompanying Quarterly Report on Form 10-Q of PG&E Corporation for the quarter ended June 30, 2005, I, Christopher P. Johns, Senior Vice President, Chief Financial Officer and Controller 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 June 30, 2005, 2004, 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 June 30, 2005, fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

CHRISTOPHER P. JOHNS

CHRISTOPHER P. JOHNS

Senior Vice President,

Chief Financial Officer and Controller

August 3, 2005

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

In connection with the accompanying Quarterly Report on Form 10-Q of Pacific Gas and Electric Company for the quarter ended June 30, 2005, I, Gordon R. Smith, President and Chief Executive Officer of Pacific Gas and Electric Company, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

- (1) such Quarterly Report on Form 10-Q of Pacific Gas and Electric Company for the quarter ended June 30, 2005, 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 June 30, 2005, fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

GORDON R. SMITH

GORDON R. SMITH

President and Chief Executive Officer

August 3, 2005

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

In connection with the accompanying Quarterly Report on Form 10-Q of Pacific Gas and Electric Company for the quarter ended June 30, 2005, I, Kent M. Harvey, 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 June 30, 2005, 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 June 30, 2005, fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

KENT M. HARVEY

KENT M. HARVEY

Senior Vice President, Chief Financial Officer
and Treasurer

August 3, 2005

