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FORM 10-K
(Annual Report)

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Fiscal Year Ended December 31, 2006

Or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission File Number	Exact Name of Registrant as specified in its charter	State or Other Jurisdiction of Incorporation or Organization	IRS Employer Identification Number
1-12609	PG&E CORPORATION	California	94-3234914
1-2348	PACIFIC GAS AND ELECTRIC COMPANY	California	94-0742640

PG&E Corporation
One Market, Spear Tower
Suite 2400
San Francisco, California 94105
(Address of principal executive offices) (Zip Code)
(415) 267-7000
(Registrant's telephone number, including area code)

Pacific Gas and Electric Company
77 Beale Street
P.O. Box 770000
San Francisco, California 94177
(Address of principal executive offices) (Zip Code)
(415) 973-7000
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
PG&E Corporation: Common Stock, no par value	New York Stock Exchange
Pacific Gas and Electric Company: First Preferred Stock, cumulative, par value $25 per share:	American Stock Exchange
Redeemable: 5% Series A, 5%, 4.80%, 4.50%, 4.36%	
Nonredeemable: 6%, 5.50%, 5%	

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act:

PG&E Corporation	Yes ☒	No ☐
Pacific Gas and Electric Company	Yes ☒	No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act:

PG&E Corporation	Yes ☐	No ☒
Pacific Gas and Electric Company	Yes ☐	No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

PG&E Corporation	Yes ☒	No ☐
Pacific Gas and Electric Company	Yes ☒	No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K:

PG&E Corporation	☒
Pacific Gas and Electric Company	☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of “accelerated filer” and “large accelerated filer” in Rule 12b-2 of the Exchange Act. (Check one):

PG&E Corporation	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐
Pacific Gas and Electric Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒

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

PG&E Corporation	Yes ☐ No ☒
Pacific Gas and Electric Company	Yes ☐ No ☒

Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants as of June 30, 2006, the last business day of the second fiscal quarter:

PG&E Corporation Common Stock	$13,640 million
Pacific Gas and Electric Company Common Stock	Wholly owned by PG&E Corporation

Common Stock outstanding as of February 20, 2007:

PG&E Corporation:	350,817,275 (excluding shares held by a wholly owned subsidiary)
Pacific Gas and Electric Company:	Wholly owned by PG&E Corporation

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the documents listed below have been incorporated by reference into the indicated parts of this report, as specified in the responses to the item numbers involved:

Designated portions of the combined 2006 Annual Report to Shareholders	Part I (Item 1, Item 1.A.), Part II (Items 5, 6, 7, 7A, 8 and 9A)
Designated portions of the Joint Proxy Statement relating to the 2007 Annual Meetings of Shareholders	Part III (Items 10, 11, 12, 13 and 14)

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UNITS OF MEASUREMENT

1 Kilowatt (kW)	=	One thousand watts
1 Kilowatt-Hour (kWh)	=	One kilowatt continuously for one hour
1 Megawatt (MW)	=	One thousand kilowatts
1 Megawatt-Hour (MWh)	=	One megawatt continuously for one hour
1 Gigawatt (GW)	=	One million kilowatts
1 Gigawatt-Hour (GWh)	=	One gigawatt continuously for one hour
1 Kilovolt (kV)	=	One thousand volts
1 MVA	=	One megavolt ampere
1 Mcf	=	One thousand cubic feet
1 MMcf	=	One million cubic feet
1 Bcf	=	One billion cubic feet
1 MDth	=	One thousand decatherms

PART I

Item 1. *Business.*

General

Corporate Structure and Business

PG&E Corporation, incorporated in California in 1995, is a holding company whose primary purpose is to hold interests in energy-based businesses. PG&E Corporation conducts its business principally through Pacific Gas and Electric Company, or the Utility, a public utility operating in northern and central California. The Utility engages in the businesses of electricity and natural gas distribution, electricity generation, procurement and transmission, and natural gas procurement, transportation and storage. The Utility was incorporated in California in 1905. PG&E Corporation became the holding company of the Utility and its subsidiaries on January 1, 1997.

The Utility served approximately 5.1 million electricity distribution customers and approximately 4.2 million natural gas distribution customers at December 31, 2006. The Utility had approximately $34.4 billion of assets at December 31, 2006, and generated revenues of approximately $12.5 billion in 2006. Its revenues are generated mainly through the sale and delivery of electricity and natural gas. The Utility is regulated primarily by the California Public Utilities Commission, or the CPUC, and the Federal Energy Regulatory Commission, or the FERC.

Corporate and Other Information

The principal executive office of PG&E Corporation is located at One Market, Spear Tower, Suite 2400, San Francisco, California 94105, and its telephone number is (415) 267-7000. The principal executive office of the Utility is located at 77 Beale Street, P.O. Box 770000, San Francisco, California 94177, and its telephone number is (415) 973-7000. PG&E Corporation and the Utility file various reports with the Securities and Exchange Commission, or the SEC. These reports, including Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to those reports filed or furnished pursuant to Sections 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, are available free of charge on both PG&E Corporation's website, *www.pgecorp.com* , and the Utility's website, *www.pge.com* . The information contained on these websites is not incorporated by reference into this Annual Report on Form 10-K and should not be considered part of this report.

Employees

At December 31, 2006, PG&E Corporation and its subsidiaries had approximately 20,400 employees, including approximately 20,200 employees of the Utility. Of the Utility's employees, approximately 13,400 are covered by collective bargaining agreements with three labor unions: the International Brotherhood of Electrical Workers, Local 1245, AFL-CIO, or the IBEW; the Engineers and Scientists of California, IFPTE Local 20, AFL-CIO and CLC, or the ESC; and the Service Employees International Union, Local 24/7, or the SEIU. The ESC and IBEW collective bargaining agreements expire on December 31, 2008. The SEIU collective bargaining agreement expires on February 28, 2009.

Forward-Looking Statements

This combined Annual Report on Form 10-K, including the information incorporated by reference from the joint Annual Report to Shareholders for the year ended December 31, 2006, or the 2006 Annual Report, contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements are based on current estimates, expectations and projections about future events, and assumptions regarding these events and management's knowledge of facts as of the date of this report. These forward-looking statements relate to , among other matters, estimated capital expenditures, estimated Utility rate base, estimated environmental remediation liabilities, the anticipated outcome of various regulatory and legal proceedings, future cash flows, and the level of future equity or debt issuances, and are also identified by words such as “assume,” “expect,” “intend,” “plan,” “project,” “believe,” “estimate,” “predict,” “anticipate,” “aim, “ “may,” “might,” “should,” “would,” “could,” “goal,” “potential” and similar expressions. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

- the Utility's ability to timely recover costs through rates;
- the outcome of regulatory proceedings, including ratemaking proceedings pending at the CPUC and the FERC;
- the adequacy and price of electricity and natural gas supplies, and the ability of the Utility to manage and respond to the volatility of the electricity and natural gas markets;
- the effect of weather, storms, earthquakes, fires, floods, disease, other natural disasters, explosions, accidents, mechanical breakdowns, acts of terrorism, and other events or hazards that could affect the Utility's facilities and operations, its customers and third parties on which the Utility relies;
- the potential impacts of climate change on the Utility's electricity and natural gas operations;
- changes in customer demand for electricity and natural gas resulting from unanticipated population growth or decline, general economic and financial market conditions, changes in technology including the development of alternative energy sources, or other reasons;
- operating performance of the Utility's Diablo Canyon nuclear generating facilities, or Diablo Canyon, the occurrence of unplanned outages at Diablo Canyon, or the temporary or permanent cessation of operations at Diablo Canyon;
- the ability of the Utility to recognize benefits from its initiatives to improve its business processes and customer service;
- the ability of the Utility to timely complete its planned capital investment projects;
- the impact of changes in federal or state laws, or their interpretation, on energy policy and the regulation of utilities and their holding companies;
- the impact of changing wholesale electric or gas market rules, including the California Independent System Operator's , or the CAISO's, new rules to restructure the California wholesale electricity market;
- how the CPUC administers the conditions imposed on PG&E Corporation when it became the Utility's holding company;
- the extent to which PG&E Corporation or the Utility incurs costs in connection with pending litigation that are not recoverable through rates, from third parties, or through insurance recoveries;
- the ability of PG&E Corporation and/or the Utility to access capital markets and other sources of credit;
- the impact of environmental laws and regulations and the costs of compliance and remediation; and
- the effect of municipalization, direct access, community choice aggregation, or other forms of bypass.

For more information about 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, see the discussion under the heading "Risk Factors" that appears near the end of the section entitled " Management's Discussion and Analysis of Financial Condition and Results of Operations ," or the MD&A, in the 2006 Annual Report that is incorporated by reference into this Annual Report on Form 10-K. PG&E Corporation and the Utility do not undertake an obligation to update forward-looking statements, whether in response to new information, future events or otherwise.

PG&E Corporation's Regulatory Environment

Federal Energy Regulation

As a public utility holding company, PG&E Corporation is subject to the requirements of the Energy Policy Act of 2005, or the EPAct, which became effective on February 8, 2006. Among its key provisions, the EPAct repealed the Public Utility Holding Company Act of 1935 and enacted the Public Utility Holding Company Act of 2005, or PUHCA 2005. Under PUHCA 2005, public utility holding companies fall principally under the regulatory oversight of the FERC, an independent agency within the U.S. Department of Energy, or the DOE.

During 2006, the FERC issued rules implementing PUHCA 2005 that impose on holding companies and their subsidiaries various requirements concerning access to books and records, accounting, record retention and the filing of reports. On June 15, 2006, PG&E Corporation filed a notification of waiver with the FERC, which was deemed granted by operation of law on August 14, 2006. The effect of this waiver is to exempt PG&E Corporation and its subsidiaries from all requirements of PUHCA 2005 other than the obligation to provide access to their books and records to the FERC and the CPUC for ratemaking purposes. The books and records provisions to which PG&E Corporation and its subsidiaries remain subject under PUHCA 2005 are largely duplicative of other provisions under the Federal Power Act of 1935 and state law.

In addition to enacting PUHCA 2005, the EPAct also significantly modified the FERC's authority and standard of review for mergers and consolidations involving public utilities and their holding companies under Section 203 of the Federal Power Act of 1935.

State Energy Regulation

PG&E Corporation is not a public utility under the laws of California. The CPUC has authorized the formation of public utility holding companies subject to various conditions related to finance, human resources, records and bookkeeping, and the transfer of customer information. The financial conditions provide that:

- the Utility cannot guarantee any obligations of PG&E Corporation without prior written consent from the CPUC;
- the Utility's dividend policy must be established by the Utility's Board of Directors as though the Utility were a stand-alone utility company;
- the capital requirements of the Utility, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner, must be given first priority by PG&E Corporation's Board of Directors (known as the “first priority” condition); and
- The Utility must maintain on average its CPUC-authorized utility capital structure, although it can request a waiver of this condition if an adverse financial event reduces the Utility's equity ratio by 1% or more.

(As discussed below under “Item 3 - Legal Proceedings,” the California Attorney General and the City and County of San Francisco have alleged that PG&E Corporation and its directors, as well as the directors of the Utility, violated the CPUC’s holding company conditions during the California 2000-2001 energy crisis. PG&E Corporation and the Utility believe that they have complied with applicable statutes, CPUC decisions, rules and orders.)

The CPUC also has adopted complex and detailed rules governing transactions between California's electricity and natural gas distribution companies and their non-regulated affiliates. The rules address the use of the regulated utilities’ names and logos by their non-regulated affiliates, the separation of regulated utilities and their non-regulated affiliates, information exchange among the affiliates, and energy procurement-related transactions among regulated utilities and their non-regulated affiliates. The rules also prohibit each utility from engaging in certain practices that would discriminate against energy service providers that compete with that utility's non-regulated affiliates. In December 2006, the CPUC revised its rules to, among other changes:

- emphasize that the holding company may not aid or abet a utility's violation of the rules or act as a conduit to provide confidential information to an affiliate;
- require prior CPUC approval before the utility can contract with an affiliate for resource procurement (*e.g.*, electricity or gas), except in blind transactions where the identity of the other party is not known until the transaction is consummated;
- require certain key officers to provide annual certifications of compliance with the affiliate rules;

- prohibit certain key officers from serving in the same position at both the utility and the holding company, or, in the alternative, prohibit the sharing of lobbying, regulatory relations and certain legal services (except for legal services necessary to the provision of permitted shared services);

- require the utility to obtain a “nonconsolidation opinion” indicating that it would not be consolidated into a bankruptcy of its holding company;

- adopt as part of the affiliate rules the utilities’ current requirements to maintain a balanced capital structure (proportions of equity, long term debt, and preferred stock) consistent with that most recently determined to be reasonable by the CPUC; and

- make the CPUC's Energy Division responsible for hiring the independent auditors to conduct the biennial audits to verify that the utility is in compliance with the affiliate rules.

The CPUC has established specific penalties and enforcement procedures for affiliate rules violations. Utilities are required to self-report affiliate rules violations.

The Utility's Regulatory Environment

Various aspects of the Utility's business are subject to a complex set of energy, environmental and other governmental laws, regulations and regulatory proceedings at the federal, state and local levels. In addition to enacting PUHCA 2005 to replace the Public Utility Holding Company Act of 1935 as discussed above, the EPAct significantly amended various federal energy laws applicable to electric and natural gas markets, including the Federal Power Act of 1935 , the Natural Gas Act of 1938 and the Public Utility Regulatory Policies Act of 1978, or PURPA.

This section and the “Ratemaking Mechanisms” section below summarize some of the more significant laws, regulations and regulatory mechanisms affecting the Utility. These summaries are not an exhaustive description of all the laws, regulations and regulatory proceedings that affect the Utility. The energy laws, regulations and regulatory proceedings may change or be implemented or applied in a way that the Utility does not currently anticipate. For discussion of specific regulatory proceedings affecting the Utility, see the section of the MD&A entitled “Regulatory Matters” in the 2006 Annual Report.

Federal Energy Regulation

The FERC

The FERC regulates the transmission and wholesale sales of electricity in interstate commerce and the transmission and sale of natural gas for resale in interstate commerce. The FERC also regulates interconnections of transmission systems with other electric systems and generation facilities; tariffs and conditions of service of regional transmission organizations, including the CAISO; and the terms and rates of wholesale electricity sales. T he EPAct granted the FERC significant new responsibilities to oversee the reliability of the nation’s electricity transmission grid, to prevent market manipulation, and to supplement state transmission siting efforts in certain electric transmission corridors that are determined to be of national interest. The EPAct also expanded the FERC’s authority to impose penalties for violation of certain federal statutes, including the Federal Power Act of 1935 and the Natural Gas Act of 1938, and for violations of FERC-approved regulations. The FERC can impose penalties of up to $1,000,000 per day per violation. The FERC has jurisdiction over the Utility's electricity transmission revenue requirements and rates, the licensing of substantially all of the Utility's hydroelectric generation facilities, and the interstate sale and transportation of natural gas.

Electric Reliability Standards; Development of Transmission Grid . As part of its directive to oversee the development of mandatory electric reliability standards to protect the national bulk power system, the FERC certified the North American Electric Reliability Corp., or the NERC, as the nation’s Electric Reliability Organization under the EPAct. The NERC is responsible for developing and enforcing electric reliability standards, subject to FERC review. All proposed reliability standards must be submitted by the NERC to the FERC for its approval. The NERC has requested the FERC to approve a delegation agreement to permit the NERC to delegate its enforcement authority for a geographic area known as the Western Interconnection to the Western Electricity Coordinating Council. Failure of the Utility to comply with FERC-approved electric reliability standards may subject the Utility to penalties. _In addition, the CAISO is responsible for providing open access electricity transmission service on a non-discriminatory basis, planning transmission system additions and assuring the maintenance of adequate reserves of generation capacity.

The FERC also has issued a rule on electric transmission pricing reforms designed to promote needed investment in energy infrastructure and to reduce transmission congestion. In addition, the FERC issued a rule to require transmission organizations with organized electricity markets to make available to load-serving entities long-term firm transmission rights so these entities can enter into long-term

transmission service arrangements without being exposed to unhedged congestion cost risk.

Prevention of Market Manipulation. The EPAct also gave the FERC broader authority to police and penalize the exercise of market power or behavior intended to manipulate the prices paid in FERC-jurisdictional transactions. In January 2006, the FERC adopted rules to prohibit market manipulation, modeling its new rules on SEC Rule 10b-5, which prohibits fraud and manipulation in the purchase or sale of securities. Under the FERC's new regulations, it is unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas, electric energy, or transportation/transmission services subject to the jurisdiction of the FERC: (1) to use or employ any device, scheme or artifice to defraud, (2) to make any untrue statement of a material fact or to omit to state a material fact necessary in order to make the statements made, in the light of the circumstances under which they were made, not misleading, or (3) to engage in any act, practice or course of business that operates or would operate as a fraud or deceit upon any person.

Several parties, including the Utility and the State of California, are seeking refunds on behalf of California electricity purchasers from electricity suppliers, including municipal and governmental entities, for overcharges incurred in the CAISO and California Power Exchange, or PX, wholesale electricity markets between May 2000 and June 2001 through various proceedings pending at the FERC and other judicial proceedings. Many issues raised in these proceedings, including the extent of the FERC's refund authority, and the amount of potential refunds after taking into account certain costs incurred by the electricity suppliers, have not been resolved. It is uncertain when these proceedings will be concluded.

The Utility has entered into settlements with various electricity suppliers resolving certain disputed claims and the Utility's refund claims against these power suppliers. The Utility continues to pursue additional refunds through settlement discussions with other electricity suppliers. Future amounts received under these settlements, and any future settlements with electricity suppliers, will be credited to customers after deductions for contingencies and amounts related to certain wholesale power purchases. For further discussion, see the section of Note 17: Commitments and Contingencies - California Energy Crisis Proceedings, of the Notes to the Consolidated Financial Statements in the 2006 Annual Report.

QF Regulation. Under PURPA, electric utilities were required to purchase energy and capacity from independent power producers that are qualifying cogeneration facilities, or QFs. To implement the purchase requirements of PURPA, the CPUC required California investor-owned electric utilities to enter into long-term power purchase agreements with QFs and approved the applicable terms, conditions, prices and eligibility requirements. The EPAct significantly amended the purchase requirements of PURPA. As amended, Section 210(m) of PURPA authorizes the FERC to waive the obligation of an electric utility under Section 210 of PURPA to purchase the electricity offered to it by a QF (under a new contract or obligation) if the FERC finds that the QF has nondiscriminatory access to one of three defined categories of competitive wholesale electricity markets. The statute permits such waivers as to a particular QF or on a "service territory-wide basis." The Utility plans to wait until after the new day-ahead market structure provided for in the CAISO's Market Redesign and Technology Update, or MRTU, initiative to restructure the California electricity market becomes effective to assess whether it will file a request with the FERC to terminate its obligations under PURPA to enter into new QF purchase obligations.

The NRC

The Nuclear Regulatory Commission, or the NRC, oversees the licensing, construction, operation and decommissioning of nuclear facilities, including the two nuclear generating units at Diablo Canyon and the Utility's retired nuclear generating unit at Humboldt Bay, or Humboldt Bay Unit 3. NRC regulations require extensive monitoring and review of the safety, radiological, environmental and security aspects of these facilities. In the event of non-compliance, the NRC has the authority to impose fines or to force a shutdown of a nuclear plant, or both. NRC safety and security requirements have, in the past, necessitated substantial capital expenditures at Diablo Canyon, and additional significant capital expenditures could be required in the future.

The NRC operating license for Diablo Canyon Unit 1 expires in November 2024 and the NRC operating license for Diablo Canyon Unit 2 expires in August 2025. Under the terms of these licenses, there must be sufficient storage capacity for the radioactive spent fuel produced by this plant. For a discussion of the Utility's spent fuel storage project, see "Environmental Matters - Nuclear Fuel Disposal," below.

State Energy Regulation

California Legislature

The Utility's operations have been significantly affected by various statutes passed by the California legislature, including:

- *Assembly Bill 1890.* Assembly Bill 1890, enacted in 1996, mandated the restructuring of the California electricity industry, commencing in 1998 with the implementation of a market framework for electricity generation in which generators and other energy providers were permitted to charge market-based rates for wholesale electricity and the investor-owned utilities' customers were given the choice to become "direct access" customers by buying energy from an alternate service provider other than the regulated utilities. Among other provisions, Assembly Bill 1890 provided for the establishment of the CAISO, as a nonprofit public benefit corporation, to operate and control the state-wide electricity transmission grid and ensure efficient use and reliable operation of the transmission grid.

- *Assembly Bill 1X.* Assembly Bill 1X, enacted during the California 2000-2001 energy crisis, authorized the California Department of Water Resources, or the DWR, beginning on February 1, 2001, to purchase electricity and sell that electricity directly to the investor-owned electric utilities' retail customers. Assembly Bill 1X required the California investor-owned electric utilities to deliver electricity purchased by the DWR under long-term contracts and to act as the DWR's billing and collection agent.

- *Assembly Bill 57.* Assembly Bill 57, enacted in September 2002 and amended by Senate Bill 1976, required the California investor-owned utilities to resume purchasing power on January 1, 2003, required the CPUC to allocate electricity to be provided under the DWR contracts among the customers of the California investor-owned electric utilities, requires the utilities to file short- and long-term electricity resource procurement plans with the CPUC for approval, and authorizes the utilities to recover their reasonable wholesale procurement costs incurred under a CPUC-approved procurement plan through the establishment of new electricity procurement balancing accounts to allow timely recovery by the utilities of differences between recorded revenues and costs incurred under the approved procurement plans.

- *Senate Bill 1078.* Senate Bill 1078, enacted in September 2002 (as amended by SB 107 enacted in September 2006 and effective on January 1, 2007) established the Renewables Portfolio Standard Program, which requires each California retail seller of electricity, except municipal utilities, to increase its purchases of eligible renewable energy (such as biomass, small hydro, wind, solar and geothermal energy) by at least 1% of its retail sales per year, the annual procurement target, so that the amount of electricity purchased from eligible renewable resources equals at least 20% of its total retail sales by 2010.

- *Assembly Bill 380.* Assembly Bill 380, enacted in September 2005, requires the CPUC in consultation with the CAISO, to establish resource adequacy requirements for all load-serving entities, including the California investor-owned electric utilities but excluding local publicly owned electric utilities. Assembly Bill 380 requires each load-serving entity to maintain physical generating capacity adequate to meet its load requirements, including, but not limited to, peak demand and planning and operating reserves, deliverable to locations and at times as may be necessary to provide reliable electric service.

- *Assembly Bill 32.* Assembly Bill 32, enacted in September 2006 to address climate change, requires the California Air Resources Board, or the CARB, to adopt regulations to limit statewide greenhouse gas emissions, to 1990 levels by 2020. (See “Environmental Matters” below for more information.)

- *Senate Bill 1368.* Senate Bill 1368, also enacted in September 2006, prohibits any load-serving entity, including investor-owned electric utilities, from entering into a long-term financial commitment for baseload generation (*i.e.* , electricity generation from a power plant that is designed and intended to provide electricity at an annualized plant capacity factor of at least 60%) unless it complies with a greenhouse gas emission performance standard. (See “Environmental Matters” below for more information.)

The CPUC

The CPUC has jurisdiction to set the rates, terms and conditions of service for the Utility's electricity distribution, electricity generation, natural gas distribution, and natural gas transportation and storage services in California. The CPUC also has jurisdiction over the Utility's issuances of securities, dispositions of utility assets and facilities, energy purchases on behalf of the Utility's electricity and natural gas retail customers, rate of return, rates of depreciation, aspects of the siting and operation of natural gas transportation assets, oversight of nuclear decommissioning and aspects of the siting of the electricity transmission system. Ratemaking for retail sales from the Utility's generation facilities is under the jurisdiction of the CPUC. To the extent that this electricity is sold for resale into wholesale markets, however, it is under the ratemaking jurisdiction of the FERC. In addition, the CPUC has general jurisdiction over most of the Utility’s operations, and regularly reviews utility performance, using measures such as the frequency and duration of outages. The CPUC also conducts investigations into various matters, such as deregulation, competition and the environment, in order to determine its future policies. The CPUC consists of five members appointed by the Governor of California and confirmed by the California State Senate for staggered six-year terms.

PG&E Corporation and the Utility entered into a settlement agreement with the CPUC on December 19, 2003 to resolve the Utility's proceeding filed under Chapter 11 of the U.S. Bankruptcy Code that had been pending in the U.S. Bankruptcy Court for the Northern District of California, or the Bankruptcy Court, since April 2001, referred to as the Chapter 11 Settlement Agreement. The nine-year Chapter 11 Settlement Agreement established certain regulatory assets and addressed various ratemaking matters in order to restore the Utility's financial health and enable it to emerge from Chapter 11 and fully resume its traditional role of providing safe and reliable electric and gas service at just and reasonable rates, subject to CPUC regulation. The terms of the Chapter 11 Settlement Agreement were incorporated into the Utility's plan of reorganization under Chapter 11 which became effective on April 12, 2004. 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 the Chapter 11 Settlement Agreement, in addition to other matters. (For more information, see Note 15 of the Notes to the Consolidated Financial Statements included in the 2006 Annual Report.)

The California Energy Resources Conservation and Development Commission

The California Energy Resources Conservation and Development Commission, commonly called the California Energy

Commission, or the CEC, is the state's primary energy policy and planning agency. The CEC is responsible for licensing of all thermal power plants over 50 MW, overseeing funding programs that support public interest energy research, advancing energy science and technology through research, development and demonstration, and providing market support to existing, new and emerging renewable technologies. In addition, the CEC is responsible for forecasting future energy needs used by the CPUC in determining the adequacy of the utilities' electricity procurement plans.

Other Regulation

The Utility obtains permits, authorizations and licenses in connection with the construction and operation of the Utility's generation facilities, electricity transmission lines, natural gas transportation pipelines and gas compressor station facilities. Discharge permits, various Air Pollution Control District permits, U.S. Department of Agriculture-Forest Service permits, FERC hydroelectric generation facility and transmission line licenses, and NRC licenses are some of the more significant examples. Some licenses and permits may be revoked or modified by the granting agency if facts develop or events occur that differ significantly from the facts and projections assumed in granting the approval. Furthermore, discharge permits and other approvals and licenses are granted for a term less than the expected life of the associated facility. Licenses and permits may require periodic renewal, which may result in additional requirements being imposed by the granting agency. (For more information see "Environmental Matters - Water Quality" below.)

The Utility has over 520 franchise agreements with various cities and counties that permit the Utility to install, operate and maintain the Utility's electric, natural gas, oil and water facilities in the public streets and roads. In exchange for the right to use public streets and roads, the Utility pays annual fees to the cities and counties. Franchise fees are computed pursuant to statute under either the Broughton Act or the Franchise Act of 1937. However, there are 38 charter cities that can set fees of their own determination. The Utility also periodically obtains permits, authorizations and licenses in connection with distribution of electricity and natural gas. Under these permits, authorizations and licenses, the Utility has rights to occupy and/or use public property for the operation of the Utility's business and to conduct certain related operations.

Competition

Historically, energy utilities operated as regulated monopolies within service territories where they were essentially the sole suppliers of natural gas and electricity services. These utilities owned and operated all of the businesses and facilities necessary to generate, transport and distribute energy. Services were priced on a combined, or bundled, basis with rates charged by the energy companies designed to include all the costs of providing these services. Under traditional cost-of-service regulation, the utilities undertook a continuing obligation to serve their customers, in return for which the utilities were authorized to charge regulated rates sufficient to recover their costs of service, including timely recovery of their operating expenses and a reasonable return on their invested capital. The objective of this regulatory policy was to provide universal access to safe and reliable utility services. Regulation was designed in part to take the place of competition and ensure that these services were provided at fair prices.

In recent years, energy utilities have faced intensifying pressures to unbundle, or price separately, those services that are no longer considered natural monopolies. The most significant of these services are the commodity components—the supply of electricity and natural gas. The driving forces behind these competitive pressures have been customers who believe that they can obtain energy at lower unit prices and competitors who want access to those customers. Regulators and legislators responded to these forces by providing for more competition in the energy industry. Regulators and legislators, to varying degrees, have required utilities to unbundle rates in order to allow customers to compare unit prices of the utilities and other providers when selecting their energy service provider.

Competition in the Electricity Industry

Federal. At the federal level, many provisions of the EPAct support the development of competition in the wholesale electric market. The EPAct has directed the FERC to develop rules to encourage fair and efficient competitive markets by employing best practices in market rules and reducing barriers to trade between markets and among regions. The EPAct also gives the FERC authority to prevent accumulation and exercise of market power by assuring that proposed mergers and acquisitions of public utility companies and their holding companies are in the public interest and by addressing market power in jurisdictional wholesale markets through its new powers to establish and enforce rules prohibiting market manipulation.

Even before the passage of the EPAct, the FERC's policies supported the development of a competitive electricity generation industry. FERC Order 888, issued in 1996, established standard terms and conditions for parties seeking access to regulated utilities' transmission grids. Order 888 requires all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to have on file open access non-discriminatory transmission tariffs, or OATT, that contain minimum terms and conditions of non-discriminatory service. The FERC's subsequent Order 2000, issued in late 1999, established national standards for regional transmission organizations, and advanced the view that a regulated, unbundled transmission sector should facilitate competition in both wholesale electricity generation and retail electricity markets. On February 16, 2007, the FERC issued Order 890 that is designed to (1) strengthen the form of OATT adopted in Order 888 to ensure that it achieves its original purpose of remedying undue discrimination; (2) provide greater specificity in the form of OATT to reduce opportunities for undue discrimination and facilitate the FERC's enforcement; and (3) increase transparency in the rules applicable to planning and use of the transmission system.

The FERC also has issued rules on the interconnection of generators larger than 20 MW with a transmission system to require regulated transmission providers, such as the Utility or the CAISO, to use standard interconnection procedures and a standard agreement for generator interconnections. These rules are intended to limit opportunities for transmission providers to favor their own generation, facilitate market entry for generation competitors by streamlining and standardizing interconnection procedures, and encourage needed investment in generation and transmission. Under the rules and associated tariffs, a new generator is required to pay for the transmission system upgrades needed in order to interconnect the generator. The generator will be reimbursed over a five-year period after the power plant achieves commercial operation. The cost of the network upgrades then is recovered by the regulated transmission provider in its overall transmission rates.

State. At the state level, Assembly Bill 1890, enacted in 1996, mandated the restructuring of the California electricity industry commencing in 1998. Assembly Bill 1890 established a market framework for electricity generation in which generators and other electricity providers were permitted to charge market-based prices for wholesale electricity through transactions conducted on the PX. As a result of the California 2000-2001 energy crisis, the PX filed a petition for bankruptcy protection and now operates solely to reconcile remaining refund amounts owed and make compliance filings as required by the FERC in the California refund proceeding still pending at the FERC. Established pursuant to AB 1890 to take control of the California investor-owned electric transmission facilities in California, the CAISO currently administers a real-time or "spot" wholesale market for the sale of electric energy. The market is used to allocate space on the transmission lines, maintain operating reserves and match supply with demand in real time. In September 2006, the FERC approved the CAISO's proposal to establish its MRTU initiative to restructure the California electricity market and to enhance power grid reliability. The FERC directed the CAISO to make certain changes to the MRTU proposal, including a requirement to comply with the FERC's new rule that regional transmission organizations provide long-term transmission rights to users of the transmission grid. The MRTU tariffs, currently estimated to become effective on January 31, 2008, will apply to all load-serving entities, including the investor-owned utilities, serving California consumers.

Assembly Bill 1890 also permitted retail end-use customers to choose their energy service provider by becoming a direct access customer. To ensure that the DWR recovers its costs to procure electricity, Assembly Bill 1X required t he CPUC to suspend the right of retail end-user customers to become direct access customers until the DWR no longer procures electricity on behalf of the customers of the California investor-owned electric utilities. The CPUC suspended direct access on September 20, 2001. The CPUC has assessed an additional charge on certain direct access customers to avoid a shift of costs from direct access customers to customers who receive bundled service. The CPUC has been asked to open a proceeding to determine whether to re-establish direct access by January 1, 2008. Although the Utility supports the ability of customers to choose their energy provider, the Utility believes t here are a number of important policy and implementation questions that must be addressed before re-establishing direct access in order to ensure that all customers are treated equitably, with no undue cost responsibility burdens or risks being placed either on any one customer group or on the utilities.

The Utility's customers may also obtain power from a "community choice aggregator" instead of obtaining power from the Utility. California Assembly Bill 117, enacted in 2002, permits cities and counties to purchase and sell electricity for their local residents and businesses once they have registered as community choice aggregators. Under Assembly Bill 117, the Utility would continue to provide distribution, metering and billing services to the community choice aggregators' customers and would be those customers' provider of electricity of last resort. However, once registration has occurred, each community choice aggregator would procure electricity for all of its residents who do not affirmatively elect to continue to receive electricity from the Utility. The CPUC has adopted rules to implement community choice aggregation, including the imposition of a surcharge on retail end-users of the community choice aggregator to prevent a shifting of costs to customers of a utility who receive bundled services. Assembly Bill 117 also authorized the Utility to recover from each community choice aggregator any costs of implementing the program that are reasonably attributable to the community choice aggregator, and to recover from customers any costs of implementing the program not reasonably attributable to a community choice aggregator.

Competition in the Natural Gas Industry

FERC Order 636, issued in 1992, required interstate natural gas pipeline companies to divide their services into separate gas commodity sales, transportation and storage services. Under Order 636, interstate natural gas pipeline companies must provide transportation service whether or not the customer (often a local gas distribution company) buys the natural gas commodity from these companies. The Utility's natural gas pipelines are located within the State of California and are exempt from FERC rules and regulations applicable to interstate pipelines. Instead, the Utility's pipeline operations are subject to the jurisdiction of the CPUC.

The Utility's gas transmission and storage system has operated under the CPUC-approved "Gas Accord" market structure since 1998. This market structure largely mimics the regulatory framework required by FERC for interstate gas pipelines. The original Gas Accord, approved by the CPUC in 1998, is a CPUC-approved s ettlement agreement reached among the Utility and many interested parties, under which the natural gas transportation and storage services that the Utility provides were separated for ratemaking purposes from the Utility's distribution services. The Gas Accord changed the terms of service and rate structure for natural gas transportation, allowing the Utility's core customers (*i.e.*, residential and small commercial customers) greater flexibility to purchase natural gas from competing suppliers. The Utility's noncore customers (*i.e.*, industrial, larger commercial and electric generation customers) purchase their natural gas from producers, marketers and brokers, and purchase their preferred mix of transportation, storage and distribution services from the Utility. Although they can select the gas suppliers of their choice, substantially all core customers buy natural gas, as well as transportation and distribution services, from the Utility as a bundled service.

Under the Gas Accord structure noncore customers have access to capacity rights for firm service, as well as interruptible (or "as-available") services. All services are offered on a nondiscriminatory basis to any creditworthy customer. The Gas Accord market structure has resulted in a robust wholesale gas commodity market at the Utility's "citygate," which refers to the interconnection between the big "backbone" gas transmission system and the smaller, downstream local transmission systems.

In December 2004, the CPUC approved the Gas Accord III which retained the Gas Accord market structure and resolved the rates, terms and conditions of service for the Utility's natural gas and transportation system through 2007. The Utility is obligated to file a new rate case proposing gas transmission and storage rates and terms and conditions of service, for the period commencing January 1, 2008. The Utility currently is scheduled to submit that filing on March 15, 2007. In the event the CPUC does not issue a final decision approving new rates effective January 1, 2008, the Gas Accord III provides that the rates and terms and conditions of service in effect as of December 31, 2007, will remain in effect, with an automatic 2 percent escalation in the rates as of January 1, 2008.

The Utility competes with other natural gas pipeline companies for customers transporting natural gas into the southern California market on the basis of transportation rates, access to competitively priced supplies of natural gas, and the quality and reliability of transportation services. The most important competitive factor affecting the Utility's market share for transportation of natural gas to the southern California market is the total delivered cost of western Canadian natural gas relative to the total delivered cost of natural gas from the southwestern United States. The total delivered cost of natural gas includes, in addition to the commodity cost, transportation costs on all pipelines that are used to deliver the natural gas, which, in the Utility's case, includes the cost of transportation of the natural gas from Canada to the California border and the amount that the Utility charges for transportation from the border to southern California. In general, when the total cost of western Canadian natural gas increases relative to other competing natural gas sources, the Utility's market share of transportation services into southern California decreases. The Utility also competes for storage services with other third-party storage providers, primarily in northern California.

PG&E Corporation, through its subsidiary, PG&E Strategic Capital, Inc., along with Fort Chicago Energy Partners, L.P. and Northwest Pipeline Corporation, have agreed to jointly pursue the development of a new 232-mile interstate gas transmission pipeline that would increase natural gas supplies for the entire West Coast region of the United States. The proposed Pacific Connector Gas Pipeline, together with the Jordan Cove liquefied natural gas, or LNG, terminal in Coos Bay, Oregon, being developed by Fort Chicago Partners, L.P., would open growing West Coast natural gas markets to diverse worldwide natural gas supply sources, providing additional alternatives to traditional Canadian, Southwest and Rocky Mountain supplies and increasing supply options and reliability. The proposed Pacific Connector Gas Pipeline would connect the proposed Jordan Cove LNG terminal to Northwest Pipeline Corporation's pipeline system in Oregon, and to the Utility's backbone gas transmission system near Malin, Oregon. Other potential interconnects include Tuscarora Gas Transmission Company's pipeline system which serves northern Nevada. The proposed Pacific Connector Gas Pipeline would be capable of delivering 1 bcf per day to the West Coast natural gas market, to customers in the Pacific Northwest through Northwest Pipeline Corporation's pipeline system, to the Utility's system for delivery to customers in California, and to customers in northern Nevada through Tuscarora Gas Transmission Company's pipeline system. On May 1, 2006, the FERC approved a request to begin the environmental assessment process for the Pacific Connector Gas Pipeline under the National Environmental Policy Act. The public will have an opportunity to participate in this process. The full application to request the FERC's authorization to construct the Pacific Connector Gas Pipeline is scheduled to be submitted to the FERC in April 2007. The development and construction of the Pacific Connector Gas Pipeline depends upon the construction of the proposed LNG terminal at Jordan Cove by Fort Chicago Partners, L.P. PG&E Corporation cannot predict whether Fort Chicago Partners, L.P. will be successful in completing the development and construction of its proposed LNG terminal. In addition, the development and construction of the proposed LNG terminal and the proposed Pacific Connector Gas Pipeline are subject to obtaining required permits, regulatory approvals, and commitments under long-term transportation

contracts. Assuming the required permits, authorizations, and long-term transportation commitments are timely received and that other conditions are timely satisfied, it is anticipated that the proposed LNG terminal and the proposed Pacific Connector Gas Pipeline would begin commercial operation in 2011.

Ratemaking Mechanisms

Cost-of-Service Ratemaking

The Utility's rates for electricity and natural gas utility services are based on its costs of service. Before rates can be set, the CPUC and the FERC must determine the amount of "revenue requirements" that the Utility can collect from its customers. The CPUC determines the Utility's revenue requirements associated with electricity and gas distribution operations, electricity generation, and natural gas transportation and storage. The FERC determines the Utility's revenue requirements associated with its electricity transmission operations.

Revenue requirements are designed to allow a utility an opportunity to recover its reasonable operating and capital costs of providing utility services, including a return of, and a fair rate of return on, its investment in utility facilities, or rate base. Revenue requirements are primarily determined based on the Utility's forecast of future costs, including the costs of purchasing electricity and natural gas for the Utility's customers. The components of revenue requirements for electricity and natural gas utility service include depreciation, operating, administrative and general expenses, taxes and return on investment, as applicable, for each area of these services, including distribution, transmission, transportation, generation, procurement and public purpose programs.

The Utility's regulatory balancing accounts are used as a mechanism for the Utility to recover amounts incurred for certain costs, primarily commodity costs. Sales balancing accounts accumulate differences between revenues and the Utility's authorized revenue requirements. Cost balancing accounts accumulate differences between incurred costs and authorized revenue requirements. The Utility also obtained CPUC approval for balancing account treatment of variances between forecasted and actual commodity costs and volumes. To the extent that the Utility is unable to recover its costs through rates because the Utility's actual costs are determined to be unreasonable or are higher than forecast, the Utility may be unable to earn its authorized rate of return.

The amount of authorized revenue requirements are allocated among customer classes (mainly residential, commercial, industrial and agricultural) and specific rates are established to produce the required revenue. The Utility's rates reflect the sum of individual revenue requirement components authorized by the CPUC and the FERC. Changes in any individual revenue requirement affect customers' rates and could affect the Utility's revenues. The timing of the CPUC and other regulatory decisions affect when the Utility is able to record the authorized revenues. In annual true-up proceedings, the Utility requests the CPUC to authorize an adjustment to electric and gas rates effective to (1) reflect over- and under-collections in the Utility's major electric and gas balancing accounts, and (2) implement various other electricity and gas revenue requirement changes authorized by the CPUC or the FERC. Generally, rate changes become effective on the first day of the following year. Balances in all CPUC-authorized accounts are subject to review, verification audit and adjustment, if necessary, by the CPUC.

Electricity and Natural Gas Distribution and Electricity Generation Operations

General Rate Cases

The General Rate Case, or GRC, is the primary proceeding in which the CPUC determines the amount of revenue requirements that the Utility is authorized to collect from customers to recover the Utility's basic business and operational costs related to its electricity and natural gas distribution and electricity generation operations. The CPUC generally conducts a GRC every three years . The CPUC sets revenue requirement levels for a three-year rate period based on a forecast of costs for the first, or test, year. Typical interveners in the Utility's GRC include the CPUC's Division of Ratepayer Advocates, or the DRA, and The Utility Reform Network, or TURN. On August 21, 2006, the Utility, together with the DRA and other parties, filed a motion with the CPUC seeking approval of a settlement agreement reached among the parties to resolve all of the issues raised by these parties and all revenue requirement-related issues raised by other parties in the Utility's 2007 GRC proceeding. The settlement agreement proposes to set the Utility's revenue requirements for a four-year period, 2007-2010, rather than for a typical three-year period. Under this proposal, the Utility's next GRC would be effective January 1, 2011. On February 13, 2007, the administrative law judge overseeing the GRC issued a proposed decision that recommends modifications to the settlement agreement. On the same day, an alternate proposed decision was issued by the assigned CPUC Commissioner in the GRC that recommends that the settlement agreement be approved. For more information, see "Regulatory Matters - 2007 General Rate Case" in the MD&A in the 2006 Annual Report.

Attrition Rate Adjustments

The CPUC may authorize the Utility to receive annual increases for the years between GRCs in the base revenues authorized for the test year of a GRC in order to avoid a reduction in earnings in those years due to, among other things, inflation and increases in invested capital. These adjustments are known as attrition rate adjustments. Attrition rate adjustments provide increases in the revenue requirements that the Utility is authorized to collect in rates for electricity and natural gas distribution and electricity generation operations. The proposed settlement agreement in the Utility's 2007 GRC includes a provision for attrition adjustments to be made in 2008, 2009 and 2010.

Cost of Capital Proceedings

The CPUC generally conducts an annual cost of capital proceeding to determine the Utility's authorized capital structure and the authorized rate of return that the Utility may earn on its electricity and natural gas distribution and electricity generation assets. The cost of capital proceeding establishes the relative weightings of common equity, preferred equity and debt in the Utility's total authorized capital structure for a specific year. The CPUC then establishes the authorized return on each component that the Utility will collect in its authorized rates. The Chapter 11 Settlement Agreement requires the CPUC to authorize a minimum return on equity for the Utility of 11.22% until the Utility receives a credit rating of "A3" from Moody's Investor Services or "A-" from Standard & Poor's Rating Services. The Utility's CPUC-authorized capital structure for 2006 and 2007 consists of 46% long-term debt, 2% preferred stock and 52% equity. The Utility's CPUC-authorized rate of return that the Utility may earn on its electricity and natural gas distribution and electricity generation rate base for 2006 and 2007 is 6.02% for long-term debt, 5.87% for preferred stock and 11.35% for equity, resulting in an overall rate of return on rate base of 8.79%. The CPUC will next re-evaluate the level of the Utility's authorized return on equity and capital structure for the calendar year 2008. The Utility is required to file its 2008 cost of capital application by May 8, 2007.

Although the FERC has authority to set the Utility's rate of return for its electricity transmission operations, the rate of return is often unspecified if the Utility's transmission rates are determined through a negotiated rate settlement. The Utility's rates of return for its backbone and local gas transmission and storage operations through 2007 have been previously set in the Gas Accord, described below, at 11.22% for the return on equity and 8.77% for the overall rate of return.

Baseline Allowance

The CPUC sets and periodically revises a baseline allowance for the Utility's residential gas and electricity customers. A customer's baseline allowance is the amount of its monthly usage that is covered under the lowest possible natural gas or electric rate. Natural gas or electricity usage in excess of the baseline allowance is covered by higher rates that increase with usage.

Public Purpose and Other Programs

The Utility administers, and/or funds, several state-mandated and CPUC-authorized public purpose and other programs. California law requires the CPUC to authorize certain levels of funding for electric and gas public purpose programs related to energy efficiency, low-income energy efficiency, research and development, and renewable energy resources. In addition, California law requires the CPUC to authorize funding for the California Solar Initiative discussed below, and other self-generation programs . In addition, the CPUC has authorized additional funding for energy efficiency and demand response programs. For 2006 expenditures, the CPUC has authorized the Utility to collect revenue requirements of approximately $583 million from electricity customers to fund these electricity pu blic purpose and other programs and to collect revenue requirements of approximately $99 million from gas customers to fund these natural gas public purpose programs. The CPUC is responsible for authorizing the programs, funding levels and cost recovery mechanisms for the Utility's operation of both energy efficiency and low-income energy efficiency programs. The CEC administers both the electric public interest research and development program and the renewable energy program on a statewide basis. In 2006, the Utility transferred $109 million to the CEC for these programs. These programs include:

- *Energy Efficiency Programs.* The CPUC has authorized 2006 through 2008 energy efficiency portfolio plans and program funding levels, not including funding for evaluation, measurement and verification, or EM&V activities for the Utility and the other investor-owned California utilities. The CPUC approved funding of approximately $867 million for the Utility's energy efficiency programs over the 2006 through 2008 period, 20% of which is to be awarded to third parties through a competitive bid process. The CPUC also has authorized funding for EM&V activities of approximately $75 million for the Utility over the 2006 through 2008 period. The increased energy efficiency funding level is part of a larger effort by the State of California to reduce consumption of fossil fuels. The increased funding level will enable both residential and business customers to take more advantage of the diverse mix of energy efficiency programs.

- *Demand Response Programs.* Demand response programs provide financial incentives and other benefits to participating customers to

curtail on-peak energy use. In March 2006, the CPUC authorized 2006 through 2008 demand response programs and funding levels for the Utility and other investor-owned California utilities. The CPUC approved funding of approximately $109 million for the Utility's demand response programs over the 2006 through 2008 period, which include some demand response programs that will be provided by third parties. In November 2006, the CPUC approved augmented demand response programs for the Utility and other investor-owned California utilities in order to promote system reliability during the summer peak demand periods of 2007 and 2008. These augmented programs were approved within the existing authorized budget. Programs requiring additional funding beyond the already authorized level will require further regulatory authorization. On February 15, 2007, the CPUC approved the Utility's proposal to start a limited deployment of an air conditioning load control program that is expected to yield 5 MW of load relief for summer 2007. In early spring 2007, the Utility anticipates requesting that the CPUC approve an expanded air conditioning load control p rogram that is expected to yield approximately 300 MW of additional load relief by the end of 2010. These increased demand response programs are part of an effort by the state of California to promote demand reduction through price-responsive programs and reliability-triggered programs.

- *Self-Generation Incentive and California Solar Initiative.* The Utility administers the self-generation incentive program authorized by the CPUC to provide incentives to electricity customers who install clean or renewable distributed generation resources that meets all or a portion of their onsite energy usage. The CPUC also authorized the California investor-owned utilities to collect an additional $2.1 billion over the 2007 through 2016 period from their customers to fund customer incentives for the installation of retail solar energy projects to serve onsite load. The goal of this program, called the California Solar Initiative, or the CSI, is to bring 1,940 MW of solar power on-line by 2017 through the California investor-owned utilities. Of the total amount authorized, the Utility has been allocated $946 million to fund customer incentives, research, development and demonstration activities (with an emphasis on the demonstration of solar and solar-related technologies), and administration expenses. California Senate Bill 1, enacted in August 2006, modified the CSI program to include participation of the California municipal utilities. The overall goal of the CSI is to install 3,000 MW (through both investor-owned electric utilities and electric municipal utilities) through 2017.

- *Low-Income Energy Efficiency Programs and California Alternate Rates for Energy.* The CPUC has approved funding of $78 million in each of 2007 and 2008 to support energy efficiency programs for low-income and fixed-income customers. The Utility also provides a discount rate called the California Alternate Rates for Energy, or CARE, for low-income customers. This rate subsidy is paid for by the Utility's other customers. For 2006, the amount of this subsidy was approximately $458 million (including avoided surcharges).

Climate Protection Tariff

In December 2006, the CPUC approved the Utility's proposal to allow customers to choose to neutralize greenhouse gas emissions associated with their energy use. Beginning in 2007, customers who choose to enroll in the program will pay a small premium on their monthly utility bill, based on their energy usage, to fund environmental projects aimed at removing carbon dioxide and other greenhouse gases from the air. The Utility estimates that this program will generate approximately $20 million during its first three years to fund these greenhouse gas reduction projects, which will initially be focused on forest restoration and conservation projects in California. The Utility would select projects to fund through a competitive bidding process using stringent criteria and protocols developed by an independent non-profit organization, the California Climate Action Registry. Project types are expected to expand beyond forestry, such as potentially to dairy biogas methane reduction projects, as more certification protocols become available. The greenhouse gas reduction projects will be overseen by an external advisory group consisting of a wide range of community groups, businesses and non-profit conservation agencies. The program will be reviewed by independent auditors and the Utility will regularly report program results to the CPUC, as well as to all participating customers.

Rate Recovery of Costs of New Electricity Generation Resources

Overview

Each California investor-owned electric utility is responsible to procure electricity to meet customer demand, plus applicable reserve margins, not satisfied from that utility's own generation facilities and existing electricity contracts (including DWR allocated contracts). Each utility must submit a long-term procurement plan covering a ten-year period to the CPUC for approval. California legislation, Assembly Bill 57, allows the California investor-owned utilities to recover their wholesale electricity procurement costs incurred in compliance with their CPUC-approved procurement plans. After CPUC approval of the procurement plans, the utilities may, if appropriate, conduct a competitive request for offers, or RFO, from providers of all potential sources of new generation (*e.g.*, conventional or renewable resources to be provided under turnkey developments, buyouts or power purchase agreements) to meet the utility's projected need for electricity resources. Agreements entered into after the conclusion of the competitive bidding process are submitted to the CPUC for approval, along with a request for the CPUC to authorize revenue requirements to recover the costs associated with that contract. If necessary, the utilities conduct separate competitive solicitations to meet their resource adequacy and renewable energy resource requirements. The utilities submit the contracts after the conclusion of these solicitations to the CPUC for approval and authorization of the associated revenue requirements.

The Utility recovers its electricity procurement costs and the fuel costs for the Utility's own generation facilities (but excluding the costs of electricity allocated to the Utility under DWR contracts) through the Energy Resource Recovery Account, or the ERRA, a balancing account authorized by the CPUC in accordance with Assembly Bill 57. The ERRA tracks the difference between the authorized revenue requirement and actual costs incurred under the Utility's authorized procurement plans and contracts. To determine the authorized revenue requirement recorded in the ERRA, each year the CPUC reviews the Utility's forecasted costs under power purchase agreements and fuel costs. Although California legislation requiring the CPUC to adjust a utility's retail electricity rates when the forecast aggregate over-collections or under-collections in the ERRA exceed 5% of a utility's prior year electricity procurement revenues (excluding amounts collected for the DWR contracts) expired on January 1, 2006, the CPUC has extended this mandatory rate adjustment mechanism for the length of a utility's resource commitment or 10 years, whichever is longer. The CPUC also 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 Chapter 11 Settlement Agreement also provides that the Utility will recover its reasonable costs of providing utility service, including power procurement costs.

The authorized revenue requirements for capital costs and non-fuel operating and maintenance costs for Utility-owned generation are addressed in the Utility's GRC. The revenue requirement to recover the initial capital costs for CPUC-approved utility owned generation projects will be recovered through a balancing account, the Utility Generation Balancing Account, or the UGBA, which will track the difference between the CPUC-approved forecast of initial capital costs, adjusted from time to time as permitted by the CPUC, and actual costs. The initial revenue requirement for the utility-owned projects generally would begin to accrue in the UGBA as of the new facility's commercial operation date or the date a completed facility is transferred to the Utility, and would be included in rates on January 1 of the following year.

Costs Incurred Under New Power Purchase Agreements

During 2006, the CPUC approved several power purchase agreements with third parties in accordance with the Utility's CPUC-approved long-term procurement plan and to meet renewable energy and resource adequacy requirements. The CPUC also authorized the Utility to recover fixed and variable costs associated with these contracts through the ERRA.

For new non-renewable generation purchased from third parties under power purchase agreements, the utilities may elect to recover any above-market costs through either (1) the imposition of a non-bypassable charge imposed on bundled and departing customers only or (2) the allocation of the "net capacity costs" (*i.e.* , contract price less energy revenues) to all "benefiting customers" in the utilities' service territory, including direct access customers and community choice aggregation customers. (For information about the status of direct access and community choice aggregation, see the section above entitled "Competition - Competition in the Electricity Industry.") The non-bypassable charge can be imposed from the date of signing a power purchase agreement and last for 10 years from the date the new generation unit comes on line or for the term of the contract, whichever is less. Utilities are allowed to justify a cost recovery period longer than 10 years on a case-by-case basis.

If a utility elects to use the net capacity cost allocation method, the net capacity costs would be allocated for the term of the contract or 10 years, whichever is less, starting on the date the new generation unit comes on line. Under this allocation mechanism, the energy rights to the contract are auctioned off to maximize the energy revenues and minimize the net capacity costs that would be subject to allocation. If no bids are accepted for the energy rights, the utility would retain the rights to the energy and would value it at spot market prices for the purposes of determining the net capacity costs to be allocated until the next periodic auction.

Costs of Utility-Owned Generation Resource Projects

During 2006, the CPUC approved three agreements related to Utility-owned generation projects. The CPUC also authorized the amount of revenue requirements that the Utility is authorized to recover related to each project to recover capital costs and non-fuel operations and maintenance costs.

- *Gateway Generating Station.* In June 2006, the CPUC authorized the Utility to acquire the equipment, permits and contracts relating to a partially completed 530-MW power plant in Antioch, California, referred to as the Gateway Generating Station, or Gateway. The Utility completed the acquisition in November 2006. The CPUC authorized the Utility to recover approximately $295 million in capital costs to complete the construction of the facility as well as costs for its operation. On February 15, 2007, the CPUC approved the Utility's request to recover an additional approximately $75 million necessary to convert the plant from fresh water cooling to dry cooling in order to reduce the environmental impact of the facility and as a result of changes to Gateway's environmental permits. The Utility also has requested the CEC to amend the facility's current permit to authorize the plant to be converted from fresh water cooling to dry cooling. The Utility expects that the CEC will issue a decision in the second quarter of 2007. Subject to obtaining the permit amendment from the CEC, meeting construction schedules, operational performance requirements and other conditions, t he Utility estimates that it will complete construction of the Gateway facility and commence operations in 2009

Colusa Power Plant. In November 2006, the CPUC approved an agreement f or the development and construction of a 657-MW power plant to be located in Colusa County, California. The CPUC adopted an initial capital cost for the Colusa project that is equal to the sum of the fixed contract costs plus the Utility's estimated owner's costs and a contingency amount to account for the risk and uncertainty in the estimation of owner's costs. (Owner's costs include the Utility's expenses for

- *Colusa Power Plant.* In November 2006, the CPUC approved an agreement f or the development and construction of a 657-MW power plant to be located in Colusa County, California. The CPUC adopted an initial capital cost for the Colusa project that is equal to the sum of the fixed contract costs plus the Utility's estimated owner's costs and a contingency amount to account for the risk and uncertainty in the estimation of owner's costs. (Owner's costs include the Utility's expenses for legal, engineering and consulting services as well as the costs for internal personnel and overhead related to the project.) The CPUC also authorized the Utility to adjust the initial capital cost for the Colusa project to reflect any actual incentive payments made to, or liquidated damages received from, the contractors through notification to the CPUC but without a reasonableness review. Subject to obtaining required permits, meeting construction schedules, operational performance requirements and other conditions, it is anticipated that the Colusa project will commence operations in 2010 at an estimated cost of approximately $673 million.

- *Humboldt Bay.* In November 2006, the CPUC also approved an agreement for the construction of a 163-MW power plant to re-power the Utility's existing Humboldt Bay power plant, which is at the end of its useful life. The CPUC adopted an initial capital cost of the Humboldt Bay project equal to the sum of the fixed contract costs plus the Utility's estimated owner's costs, but limited the contingency amount for owner's costs to 5 percent of the fixed contract cost and estimated owner's costs. Subject to obtaining required permits and meeting construction schedules, operational performance requirements and other conditions, it is anticipated that the Humboldt Bay project will commence operations in 2009 at an estimated cost of approximately $239 million.

On December 11, 2006, the Utility submitted its 2006 long-term procurement plan covering procurement over 2007-2016 to the CPUC for approval. For more information about the 2006 plan, see the section of MD&A in the 2006 Annual Report entitled "Regulatory Matters - Electricity Generation Resources."

DWR Electricity and DWR Revenue Requirements

During the California 2000-2001 energy crisis, the DWR entered into long-term contracts to purchase electricity from third parties. The electricity provided under these contracts has been allocated to the electric customers of the three California investor-owned electric utilities. The DWR pays for its costs of purchasing electricity from a revenue requirement collected from these customers through a rate component called the DWR "power charge." The rates that these customers pay also include a "bond charge" to pay a share of the DWR's revenue requirements to recover costs associated with the DWR's $11.3 billion bond offering completed in November 2002. The proceeds of this bond offering were used to repay the State of California and lenders to the DWR for electricity purchases made before the implementation of the DWR's revenue requirement and to provide the DWR with funds to make its electricity purchases. Because the Utility acts as a billing and collection agent for the DWR, amounts collected for the DWR and any adjustments are not included in the Utility's revenues.

Electricity Transmission

The Utility's electricity transmission revenue requirements and its wholesale and retail transmission rates are subject to authorization by the FERC. The Utility has two main sources of transmission revenues: charges under the Utility's transmission owner tariff and charges under specific contracts with wholesale transmission customers that the Utility entered into before the CAISO began its operations in March 1998. These wholesale customers are referred to as existing transmission contract customers and are charged individualized rates based on the terms of their contracts. Other customers pay transmission rates that are established by the FERC in the Utility's transmission owner tariff rate cases. These FERC-approved rates are included by the CPUC in the Utility's retail electric rates, consistent with the federal filed rate doctrine, and are collected from retail electric customers receiving bundled service.

Transmission Owner Rate Cases

The primary FERC rate-making proceeding to determine the amount of revenue requirements the Utility is authorized to recover for its electric transmission costs and to earn its return on equity is the transmission owner rate case. A transmission owner rate case is generally held every year and sets rates for a one-year period. The Utility is typically able to charge new rates, subject to refund, before the outcome of the FERC ratemaking review process. The Utility's transmission owner tariff includes two rate components. The primary component consists of base transmission rates intended to recover the Utility's operating and maintenance expenses, depreciation and amortization expenses, interest expense, tax expense and return on equity. The Utility derives the majority of the Utility's transmission revenue from base transmission rates. The other component consists of r ates intended to reflect credits and charges from the CAISO. The CAISO credits the Utility for transmission

revenues received by the CAISO. The CAISO also charges the Utility for reliability service costs and imposes a transmission access charge for the Utility's use of CAISO-controlled transmission facilities in serving its customers. These credits and charges are described below.

On August 1, 2006, the Utility filed its transmission owner rate case application with the FERC requesting authorization of an annual transmission revenue requirement effective October 1, 2006. On September 29, 2006, the FERC issued an order accepting the Utility's rate application, suspending the requested rate changes for five months to become effective March 1, 2007, subject to refund. On February 15, 2007, the Utility submitted an offer of settlement reached by the parties and requested that the settlement judge recommend that the FERC approve the settlement. For more information, see "Regulatory Matters - FERC Transmission Rate Case" in the MD&A in the 2006 Annual Report.

CAISO Transmission Revenues

CAISO transmission revenues include:

- the proceeds received from the CAISO for wholesale wheeling service (*i.e.* , the transfer of electricity that is being sold in the wholesale market) that the CAISO provides to third parties using the Utility's transmission facilities, and

- revenues that the CAISO collects from transmission users to relieve congestion on the Utility's transmission line (either in the form of financial hedges such as firm transmission rights relating to future deliveries of electricity or in the form of a usage charge to manage congestion relating to real time delivery of electricity).

The amount of CAISO transmission revenues is adjusted by the shortfall or surplus resulting from any cost differences between the amount the Utility is entitled to receive from certain wholesale customers under specific contracts and the amount the Utility is entitled to receive or be charged for scheduling services under the CAISO's rules and protocols.

Reliability Service Costs

The CAISO has entered into reliability must run, or RMR, agreements with various power plant owners, including the Utility, that require designated units in certain power plants, known as RMR units, to remain available to generate electricity upon the CAISO's demand when the generation from those RMR units is needed for local transmission system reliability. RMR agreements are established or extended by the CAISO on an annual basis. As a participating transmission owner under the Transmission Control Agreement with the CAISO, the Utility is responsible for reimbursing the CAISO for the RMR payments it makes to power plant owners within or adjacent to the Utility's service territory. The Utility tracks these costs in the reliability services balancing account. Periodically, the Utility's transmission owner rates are adjusted to refund over-collections to the Utility's customers as a result of the effect of these reliability service costs or to collect any under-collections from customers. During 2006, the CPUC adopted rules to implement state law requirements for California investor-owned utilities to meet resource adequacy requirements, including rules to address local transmission system reliability issues. As the utilities fulfill their responsibility to meet these requirements, the number of RMR agreements with the CAISO and the associated costs will decline.

For further discussion of other RMR-related issues, see the section of Note 17: Commitments and Contingencies - Reliability Must Run Agreements, of the Notes to the Consolidated Financial Statements in the 2006 Annual Report.

Transmission Access Charge

The CAISO imposes a transmission access charge on users of the CAISO-controlled electric transmission grid. The CAISO's transmission access charge methodology approved by the FERC in December 2004, provides for a transition over a 10-year period to a uniform statewide high-voltage transmission rate, based on the revenue requirements associated with facilities operated at 200 kV and above of all transmission owning entities that become participating transmission owners under the CAISO tariff. The transmission access charge methodology may result in a cost shift from transmission owners whose costs for existing transmission facilities at 200 kV and above are higher than that embedded in the uniform transmission access charge rate, to transmission owners with lower embedded costs for existing high voltage transmission, such as the Utility. The Utility's obligation for this cost differential has been capped at $32 million per year during the 10-year transition period.

Natural Gas

The Gas Accord

Under a ratemaking pact called the Gas Accord, the Utility's natural gas transportation and storage services were separated for ratemaking purposes from its distribution services. The Gas Accord established natural gas transportation rates and natural gas storage rates. In December 2004, the CPUC approved a multi-party settlement agreement, the Gas Accord III, to retain the Gas Accord market structure, and resolve the rates, and terms and conditions of service for the Utility's natural gas transportation and storage system for the three-year period 2005 through 2007. Under this framework, the costs associated with the Utility's local transportation and gas storage assets that are used for service to core customers are recovered through balancing account mechanisms that adjust for the difference between actual usage and forecast usage. In addition, approximately 65% of the costs associated with the Utility's backbone gas transmission system that is used to serve core customers are recovered through fixed charges. The remaining 35% of these costs are recoverable through volumetric charges. Revenues from these charges vary depending on the level of throughput volume. The costs that are recoverable through balancing accounts or fixed reservation charges account for approximately 45% of the Utility's total revenue requirement for gas transmission and storage. The remainder of the Utility's gas transmission and storage costs are recovered from core customers through volumetric charges and from noncore customers under firm or interruptible transmission or storage contracts. The Utility's recovery of this portion of its costs depend on the level of throughput volume, gas prices, and the extent to which noncore customers contract for firm services.

The Utility is obligated to file a new rate case proposing gas transmission and storage rates and terms and conditions of service, for the period commencing January 1, 2008. The Utility currently is scheduled to submit that filing on March 15, 2007. In the event the CPUC does not issue a final decision approving new rates effective January 1, 2008, Gas Accord III provides that the rates and terms and conditions of service in effect as of December 31, 2007, will remain in effect, with an automatic 2 percent escalation in the rates as of January 1, 2008.

Biennial Cost Allocation Proceeding

Certain of the Utility's natural gas distribution costs and balancing account balances are allocated to customers in the Biennial Cost Allocation Proceeding. This proceeding normally occurs every two years and is updated in the interim year for purposes of adjusting natural gas rates to recover from customers any under-collection, or refund to customers any over-collection, in the balancing accounts. Balancing accounts for gas distribution and other authorized expenses accumulate differences between authorized amounts and actual revenues.

Natural Gas Procurement

The Utility sets the natural gas procurement rate for core customers monthly based on the forecasted costs of natural gas, core pipeline capacity and storage costs. The Utility reflects the difference between actual natural gas purchase costs and forecasted natural gas purchase costs in several natural gas balancing accounts, with under-collections and over-collections taken into account in subsequent monthly rates.

The Utility recovers the cost of gas (subject to the ratemaking mechanism discussed below), acquired on behalf of core procurement customers, through its retail gas rates. The Utility is protected against after-the-fact reasonableness reviews of these gas procurement costs under an incentive mechanism known as the Core Procurement Incentive Mechanism, or CPIM. Under the CPIM, the Utility's purchase costs for a twelve-month period are compared to an aggregate market-based benchmark based on a weighted average of published monthly and daily natural gas price indices at the points where the Utility typically purchases natural gas. The CPIM establishes a "tolerance band" around the benchmark index price, and all costs within the tolerance band are fully recovered from core customers. If total natural gas costs fall below the tolerance band, the Utility's customers and shareholders will share 75% and 25% of the savings below the tolerance band, respectively. Conversely, if total natural gas costs rise above the tolerance band, the Utility's core customers and shareholders share equally the costs above the tolerance band. The shareholder award is capped at the lower of 1.5% of total natural gas commodity costs or $25 million. While this incentive mechanism remains in place, changes in the price of natural gas, consistent with the market-based benchmark, are not expected to materially impact net income. (For more information see the "Risk Management Activities" section of MD&A in the 2006 Annual Report).

Interstate and Canadian Natural Gas Transportation and Storage

The Utility's interstate and Canadian natural gas transportation agreements with third-party service providers are governed by tariffs that detail rates, rules and terms of service for the provision of natural gas transportation services to the Utility on interstate and Canadian pipelines. United States tariffs are approved for each pipeline for service to all of its shippers, including the Utility, by the FERC in a FERC ratemaking review process, and the applicable Canadian tariffs are approved by the Alberta Energy and Utilities Board and the National Energy Board. The Utility's agreements with interstate and Canadian natural gas transportation service providers are administered as part of the Utility's core natural gas procurement business. Their purpose is to transport natural gas from the points at which the Utility takes delivery of natural gas (typically in Canada and the southwestern United States) to the points at which the Utility's natural gas transportation system begins.

Electric Utility Operations

Electricity Resources

The following table shows the percentage of the Utility's total sources of electricity for 2006 represented by each major electricity resource:

Owned generation (nuclear, fossil fuel-fired and hydroelectric facilities)	40%
DWR	24%
Qualifying Facilities/Renewables	20%
Irrigation Districts	6%
Other Power Purchases	10%

The Utility is required to dispatch, or schedule, all of the electricity resources within its portfolio, including electricity provided under DWR contracts, in the most cost-effective way. Least-cost dispatch requires the Utility, in certain cases, to schedule more electricity than is necessary to meet its retail load and to sell this additional electricity on the wholesale electricity 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.

Owned Generation Facilities

At December 31, 2006, the Utility owned and operated the following generation facilities, all located in California, listed by energy source:

Generation Type	County Location	Number of Units	Net Operating Capacity (MW)
Nuclear:			
Diablo Canyon	San Luis Obispo	2	2,240
Hydroelectric:			
Conventional	16 counties in northern and central California	107	2,684
Helms pumped storage	Fresno	3	1,212
Hydroelectric subtotal		110	3,896
Fossil fuel:			
Humboldt Bay(1)	Humboldt	2	105
Mobile turbines	Humboldt	2	30
Fossil fuel subtotal		4	135
Total		116	6,271

(1) The Humboldt Bay facilities consist of a retired nuclear generation unit and two operating fossil fuel-fired plants . As described above, the CPUC has approved the Utility’s application to re-power the two fossil fuel-fired plants.

In May 2006, the Utility retired its fossil fuel-fired plant at Hunters Point in San Francisco after the completion of a new 230-kV transmission line from Redwood City to Brisbane, known as the Jefferson-Martin 230-kV Line. The Utility is in the process of decommissioning the Hunters Point power plant. The completed transmission line provides additional transmission system reliability in San Francisco and northern San Mateo County that allowed the Hunters Point fossil-fueled power plant in San Francisco to be retired.

Diablo Canyon Power Plant. The Utility's Diablo Canyon power plant consists of two nuclear power reactor units, with a total-plant net generation capacity of approximately 2,240 MW of electricity. Unit 1 began commercial operation in May 1985, and the operating license for this unit expires in November 2024. Unit 2 began commercial operation in March 1986, and the operating license for this unit expires in August 2025. For the 10-year period ended December 31, 2006, the Utility's Diablo Canyon power plant achieved an average overall capacity factor of approximately 89.8%.

The Utility has entered into various purchase agreements for nuclear fuel with terms ranging from two to five years that are intended to

ensure long-term fuel supply. For more information about these agreements, see Note 17: Commitments and Contingencies - Nuclear Fuel Agreements, of the Notes to the Consolidated Financial Statements in the 2006 Annual Report.

The following table outlines the Diablo Canyon power plant's refueling schedule for the next five years. The Diablo Canyon power plant refueling outages are typically scheduled every 16 to 21 months. The average length of a refueling outage over the last five years has been approximately 48 days. It is anticipated, however, that additional work will be required during future scheduled outages leading up to the replacement of the steam generators in Unit 2 in 2008 and in Unit 1 in 2009. The capital expenditures necessary to complete these projects are discussed further in the "Capital Expenditures" section of MD&A in the 2006 Annual Report. This additional work will lengthen the forecasted outage durations to the time periods shown below. The table below shows outages of approximately 80 days for steam generator replacements. The actual refueling schedule and outage duration will depend on the scope of the work required for a particular outage and other factors.

	2007	2008	2009	2010	2011
Unit 1					
Refueling	April	-	January	October	
Duration (days)	28	-	74	28	
Startup	May	-	April	November	
Unit 2					
Refueling	-	February	October	-	April
Duration (days)	-	76	28	-	28
Startup	-	April	November	-	May

In addition, as discussed below under "Environmental Matters - Nuclear Fuel Disposal," the Utility is constructing an on-site dry cask storage facility to store the spent nuclear fuel that is expected to be completed by 2008. To provide another storage alternative in the event that construction of the dry cask storage facility is delayed, in December 2006, the Utility completed the installation of temporary storage racks in each unit's existing spent fuel storage pool that increase the on-site storage capability to permit the Utility to operate Unit 1 until 2010 and Unit 2 until 2011. If the Utility is unable to complete the dry cask storage facility, or if construction is delayed beyond 2010, and if the Utility is otherwise unable to increase its on-site storage capacity, it is possible that the operation of Diablo Canyon may have to be curtailed or halted as early as 2010 with respect to Unit 1 and 2011 with respect to Unit 2 until such time as additional spent fuel can be safely stored.

Hydroelectric Generation Facilities. The Utility's hydroelectric system consists of 110 generating units at 68 powerhouses, including a pumped storage facility, with a total generating capacity of 3,896 MW. The system includes 99 reservoirs, 76 diversions, 174 dams, 184 miles of canals, 44 miles of flumes, 135 miles of tunnels, 19 miles of pipe and 5 miles of natural waterways. The system also includes water rights as specified in 87 permits or licenses and 160 statements of water diversion and use. With the exception of three non-jurisdictional powerhouses totaling approximately 7.7 MW, all of the Utility's powerhouses are licensed by the FERC. Pursuant to the Federal Power Act, the term of a hydroelectric project license issued by the FERC is between 30 and 50 years. In the last five years, the FERC has renewed six hydroelectric project licenses associated with a total of 699 MW. The Utility is in the process of seeking FERC renewal of licenses associated with approximately 1,314 MW of hydroelectric power. Although the original licenses associated with 917 MW of the 1,314 MW have expired, the licenses are automatically renewed each year until completion of the relicensing process. Licenses associated with approximately 2,569 MW, including the 699 MW recently relicensed, will expire between 2013 and 2043.

DWR Power Purchases

During 2006, electricity from the DWR contracts allocated to the Utility provided approximately 24% of the electricity delivered to the Utility's customers. The DWR purchased the electricity under contracts with various generators. The Utility, as an agent, is responsible for administration and dispatch of the DWR's electricity procurement contracts allocated to the Utility's customers. The DWR remains legally and financially responsible for its electricity procurement contracts. As described above under "Ratemaking Mechanisms," the Utility acts as a billing and collection agent to collect the DWR's revenue requirements from the Utility's customers. For more information regarding the DWR contracts, see Note 17: Commitments and Contingencies - Third Party Power Purchase Agreements, of the Notes to the Consolidated Financial Statements in the 2006 Annual Report.

Third-Party Power Purchase Agreements

Qualifying Facility Power Purchase Agreements. As of December 31, 2006, the Utility had agreements with 268 QFs for approximately 4,150 MW that are in operation. Agreements for approximately 3,800 MW expire at various dates between 2007 and 2028. QF power purchase agreements for approximately 350 MW have no specific expiration dates and will terminate only when the owner of the QF exercises its termination option. The Utility also has power purchase agreements with approximately 68 inoperative

QFs. The total of approximately 4,150 MW consists of approximately 2,550 MW from cogeneration projects, 600 MW from wind projects and 1,000 MW from projects with other fuel sources, including biomass, waste-to-energy, geothermal, solar and hydroelectric.

QF power purchase agreements accounted for approximately 20% of the Utility's 2006 electricity sources, 22% of the Utility's 2005 electricity sources and approximately 23% of the Utility's 2004 electricity sources. No single QF accounted for more than 5% of the Utility's 2006, 2005 or 2004 electricity sources.

Renewable Energy Contracts. California law requires that each California retail seller of electricity, except for municipal utilities, increase its purchases of renewable energy (such as biomass, wind, solar and geothermal energy) by at least 1% of its retail sales per year, so that the amount of electricity purchased from renewable resources equals at least 20% of its total retail sales by the end of 2010. During 2006, the Utility entered into several new renewable power purchase contracts that will help the Utility meet its goals. Currently, power from eligible renewable energy resources comprises approximately 12% of the Utility's retail sales. The Utility expects to comply with its 2004, 2005, 2006 and 2007 annual targets . Although the Utility expects it will achieve the 20% target using the "flexible compliance" rules by 2010, actual deliveries of renewable power may not comprise 20% of its bundled retail sales by 2010 due to such factors as the time required for the construction of new generation facilities and/or needed transmission capacity. Failure to satisfy the targets may result in a penalty of five cents per kWh, with an annual penalty cap of $25 million. The exact amount of any penalty and conditions under which it would be applied is subject to the CPUC's review of the circumstances for under-delivery.

Irrigation Districts and Water Agencies. The Utility has contracts with various irrigation districts and water agencies to purchase hydroelectric power. Under these contracts, the Utility must make specified semi-annual minimum payments based on the irrigation districts' and water agencies' debt service requirements, whether or not any hydroelectric power is supplied, and variable payments for operation and maintenance costs incurred by the suppliers. These contracts expire on various dates from 2007 to 2031. The Utility's irrigation district and water agency contracts accounted for approximately 6% of the Utility's 2006 electricity sources, and approximately 5% of the Utility's 2005 and 2004 electricity sources.

Other Power Purchase Agreements. After competitive solicitations, bilateral negotiations, and request for offers or proposals, were conducted, the Utility entered into several agreements with third party power providers d uring 2006 to meet the Utility's intermediate and long-term generation resource needs. Under these contracts, the Utility will purchase power from facilities that may start as early as January 1, 2007 to as late as 2011. These combined agreements cover an aggregate of 7,129 MW of contractual capacity that expire between December 31, 2010 and January 31, 2036. P ayments are not required under these agreements until the underlying generation facilities are operational.

For more information regarding the Utility's power purchase contracts, see Note 17: Commitments and Contingencies - Third Party Power Purchase Agreements, of the Notes to the Consolidated Financial Statements in the 2006 Annual Report.

Future Long-Term Generation Resources

In accordance with the Utility's CPUC-approved procurement plan covering 2004-2014, the Utility has entered into contracts covering 2,780 MW of new long-term electricity generation resources in northern California. Three of the agreements provide for the construction of generation facilities to be owned and operated by the Utility: the 530-MW Gateway power plant located in Antioch, California; the 657-MW Colusa power plant located in Colusa, California; and the 163-MW power plant to re-power the Utility's existing Humboldt Bay power plant, which is at the end of its useful life. Subject to obtaining required permits and meeting construction schedules, operational performance requirements and other conditions, it is anticipated that the Gateway and Humboldt Bay plants will commence operations in 2009 and the Colusa plant will commence operations in 2010. The Utility also executed five power purchase agreements that would provide approximately 1,430 MW of capacity with terms from 10 to 20 years. If permitting and construction schedules are met, the new generation facilities supporting these power purchase agreements are anticipated to begin delivering power to the grid during 2009 through 2010.

On December 11, 2006, the Utility submitted its 2006 long-term electricity procurement plan covering procurement over 2007-2016 to the CPUC for approval. The plan forecasts a need for up to an additional 2,300 MW of new dispatchable and operationally flexible capacity to come on line starting in 2011 to ensure continued reliable service. For more information about the 2006 plan, see the section of MD&A in the 2006 Annual Report entitled "Regulatory Matters - Electricity Generation Resources."

Electricity Transmission

At December 31, 2006, the Utility owned 18,640 circuit miles of interconnected transmission lines operated at voltages of 500 kV to 60 kV and transmission substations with a capacity of 53,094 MVA. Electricity is transmitted across these lines and substations and is then distributed to customers through 140,049 circuit miles of distribution lines and substations with a capacity of 26,079 MVA. In 2006, the Utility delivered 84,310 GWh to its customers, including 7,604 GWh delivered to direct access customers. The Utility is interconnected with electric power systems in the Western Electricity Coordinating Council, which includes 14 western states, Alberta and British Columbia, Canada, and parts of Mexico.

In 1998, in connection with electric industry restructuring, the California investor-owned electric utilities relinquished control, but not ownership, of their transmission facilities to the CAISO. The Utility has entered into a Transmission Control Agreement with the CAISO and other participating transmission owners (including Southern California Edison Company, San Diego Gas & Electric Company, and several California municipal utilities) under which the transmission owners have assigned operational control of their electric transmission systems to the CAISO. The Utility is required to give the CAISO two years' notice and receive approval from the FERC if it wishes to withdraw from the Transmission Control Agreement and take back operational control of its transmission facilities.

The CAISO, which is regulated by the FERC, controls the operation of the transmission system and provides open access transmission service on a nondiscriminatory basis. The CAISO also is responsible for assuring that the reliability of the transmission system is maintained. The Utility acts as a scheduling coordinator to schedule electricity deliveries to the transmission grid. The Utility also acts as a scheduling coordinator to deliver electricity produced by several governmental entities to the transmission grid under contracts the Utility entered into with these entities before the CAISO commenced operation in 1998.

In April 2006, the Utility completed a new 230-kV transmission line from Redwood City to Brisbane, known as the Jefferson-Martin 230-kV Line. The completed transmission line provides additional transmission system reliability in San Francisco and northern San Mateo County. As result of the completion of the transmission line, the Utility was able to retire the Hunters Point power plant in San Francisco. The Utility expects to undertake various transmission projects over the next few years to upgrade and expand the Utility's transmission system in order to accommodate system load growth, to secure access to renewable generation resources, and to replace aging or obsolete equipment to maintain system reliability and reduce reliance on RMR generation. These potential projects include the construction of the Midway-Gregg 500-kV transmission line designed to increase access to southern California and Southwest generation resources and to reduce RMR generation contracts in the Fresno, California, area. In addition, the Utility is currently working with several stakeholders in the western United States to assess the feasibility of new large-scale electric transmission expansion projects to address regional electricity needs over the long term. In addition, t he CPUC has adopted a procedure to enable the utilities to recover the cost of electric transmission facilities necessary to interconnect renewable energy resources if those costs cannot be recovered in FERC-approved rates.

Electricity Distribution Operations

The Utility's electricity distribution network extends throughout all or a part of 47 of California's 58 counties, comprising most of northern and central California. The Utility's network consists of 140,049 circuit miles of distribution lines (of which approximately 19% are underground and approximately 81% are overhead). There are 94 transmission substations and 48 transmission-switching stations. A transmission substation is a fenced facility where voltage is transformed from one transmission voltage level to another. There are 602 distribution substations and 110 low-voltage distribution substations. There are 55 combined transmission and distribution substations. Combined transmission and distribution substations have both transmission and distribution transformers.

The Utility's distribution network interconnects to the Utility's electricity transmission system at 1,106 points. This interconnection between the Utility's distribution network and the transmission system typically occurs at distribution substations where transformers and switching equipment reduce the high-voltage transmission levels at which the electricity transmission system transmits electricity, ranging from 500 kV to 60 kV, to lower voltages, ranging from 44 kV to 2.4 kV, suitable for distribution to the Utility's customers. The distribution substations serve as the central hubs of the Utility's electricity distribution network and consist of transformers, voltage regulation equipment, protective devices and structural equipment. Emanating from each substation are primary and secondary distribution lines connected to local transformers and switching equipment that link distribution lines and provide delivery to end-users. In some cases, the Utility sells electricity from its distribution lines or other facilities to entities, such as municipal and other utilities, that then resell the electricity.

During 2006, the Utility began the installation of an advanced metering system for virtually all of the Utility's residential and small commercial electric and gas customers. These meters will enable the Utility to measure usage of electricity on a time-of-use basis and to charge demand-responsive rates 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 expects to complete the installation of the network infrastructure and advanced meters throughout its service territory by the end of 2011. In 2006, the CPUC also approved the Utility's proposal to offer customers a new voluntary billing option called critical peak pricing, or CPP, under which customers will be able to take advantage of electricity prices that vary by day and hour, potentially reducing their bills by shifting their energy use away from critical peak periods. By shifting energy demand away from critical peak periods, the Utility anticipates that it would need to purchase less power for critical peak periods. (For more information about the advanced metering initiative, see the section entitled "Capital Expenditures" in the MD&A portion of the 2006 Annual Report.)

2006 Electricity Deliveries

The following table shows the percentage of the Utility's total 2006 electricity deliveries represented by each of its major customer classes.

Total 2006 Electricity Delivered: 84,310 GWh

Agricultural and Other Customers	5%
Industrial Customers	18%
Residential Customers	37%
Commercial Customers	40%

Electricity Distribution Operating Statistics

The following table shows certain of the Utility's operating statistics from 2002 to 2006 for electricity sold or delivered, including the classification of sales and revenues by type of service.

	2006	2005	2004	2003	2002
Customers (average for the year):					
Residential	4,417,638	4,353,458	4,366,897	4,286,085	4,171,365
Commercial	515,297	509,786	509,501	493,638	483,946
Industrial	1,212	1,271	1,339	1,372	1,249
Agricultural	79,006	78,876	80,276	81,378	78,738
Public street and highway lighting	28,799	28,021	27,176	26,650	24,119
Other electric utilities	4	4	3	4	5
Total (1)	5,041,956	4,971,416	4,985,192	4,889,127	4,759,422
Deliveries (in GWh):(2)					
Residential	31,014	29,752	29,453	29,024	27,435
Commercial	33,492	32,375	32,268	31,889	31,328
Industrial	15,166	14,932	14,796	14,653	14,729
Agricultural	3,839	3,742	4,300	3,909	4,000
Public street and highway lighting	785	792	2,091	605	674
Other electric utilities	14	33	28	76	64
Subtotal	84,310	81,626	82,936	80,156	78,230
California Department of Water Resources (DWR)	(19,585)	(20,476)	(19,938)	(23,554)	(21,031)
Total non-DWR electricity	64,725	61,150	62,998	56,602	57,199
Revenues (in millions):					
Residential	4,491	$ 3,856	$ 3,718	$ 3,671	$ 3,646
Commercial	4,414	4,114	4,179	4,440	4,588
Industrial	1,293	1,232	1,204	1,410	1,449
Agricultural	483	446	491	522	520
Public street and highway lighting	72	66	71	69	73
Other electric utilities	59	4	22	24	10
Subtotal	10,812	9,718	9,685	10,136	10,286
DWR	(2,119)	(1,699)	(1,933)	(2,243)	(2,056)
Direct access credits	—	—	—	(277)	(285)
Miscellaneous(3)	261	235	(248)	(52)	193
Regulatory balancing accounts	(202)	(327)	363	18	40

Total electricity operating revenues	$ 8,752	$ 7,927	$ 7,867	$ 7,582	$ 8,178
Other Data:					
Average annual residential usage (kWh)	7,020	6,834	6,744	6,772	6,577
Average billed revenues (cents per kWh):					
Residential	14.48	12.96	12.62	12.65	13.29
Commercial	13.18	12.71	12.95	13.92	14.65
Industrial	8.53	8.25	8.14	9.62	9.84
Agricultural	12.58	11.92	11.41	13.35	13.00
Net plant investment per customer	$ 3,148	$ 2,966	$ 2,790	$ 2,689	$ 2,105

(1) Starting in 2005, the Utility's methodology used to count customers changed from the number of billings to the number of active service agreements.

(2) These amounts include electricity provided to direct access customers who procure their own supplies of electricity.

(3) Miscellaneous revenues in 2003 include a $125 million reduction due to refunds to electricity customers from generation-related revenues in excess of generation-related costs.

Natural Gas Utility Operations

The Utility owns and operates an integrated natural gas transportation, storage and distribution system in California that extends throughout all or a part of 38 of California's 58 counties and includes most of northern and central California. In 2006, the Utility served approximately 4.2 million natural gas distribution customers. The total volume of natural gas throughput during 2006 was approximately 836 Bcf.

At December 31, 2006, the Utility's natural gas system consisted of 40,704 miles of distribution pipelines, 6,138 miles of backbone and local transmission pipelines, and three storage facilities. The Utility's distribution network connects to the Utility's transmission and storage system at approximately 2,200 major interconnection points. The Utility's backbone transmission system, composed of Lines 300, 400 and 401, is used to transport gas from the Utility's interconnection with interstate pipelines, other local distribution companies, and California gas fields to the Utility's local transmission and distribution system. The Utility's Line 300, which interconnects with the U.S. southwest and California-Oregon pipeline systems owned by third parties (Transwestern Pipeline Co., El Paso Natural Gas Company, Questar Southern Trails Pipeline Company and Kern River Pipeline Company), has a receipt capacity at the California-Arizona border of approximately 1.1 Bcf per day. The Utility's Line 400/401 interconnects with the natural gas transportation pipeline of Gas Transmission Northwest Corporation at the California-Oregon border. This line has a receipt capacity at the border of approximately 2.0 Bcf per day. Through interconnections with other interstate pipelines, the Utility can receive natural gas from all the major natural gas basins in western North America, including basins in western Canada, the Rocky Mountains and the southwestern United States. The Utility also is supplied by natural gas fields in California.

The Utility also owns and operates three underground natural gas storage fields connected to the Utility's transmission and storage system. These storage fields have a combined annual cycle capacity of approximately 42 Bcf. In addition, two independent storage operators are interconnected to the Utility's northern California transportation system.

The CPUC divides the Utility's natural gas customers into two categories: core and noncore customers. This classification is based largely on a customer's annual natural gas usage. The core customer class is comprised mainly of residential and smaller commercial natural gas customers. The noncore customer class is comprised of industrial, larger commercial and electric generation natural gas customers. In 2006, core customers represented more than 99% of the Utility's total customers and 39% of its total natural gas deliveries, while noncore customers comprised less than 1% of the Utility's total customers and 61% of its total natural gas deliveries.

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. When the Utility provides both supply and delivery, the Utility refers to the service as natural gas bundled service. Currently, over 99% of core customers, representing over 96% of core market demand, receive natural gas bundled services from the Utility.

The Utility does not provide procurement service to noncore customers. Electricity generators, cogenerators, enhanced oil recovery and refiners, and other large noncore customers may not transfer to core service, and smaller noncore customers must sign up for a minimum five-year term if they elect to transfer to core service. These restrictions were put in place because large increases in the Utility's natural gas supply portfolio demand from significant transfers of noncore customers to core service would raise prices for all other core procurement customers and obligate the Utility to reinforce its pipeline system to provide core service reliability on a short-term basis to serve this new load.

The Utility offers backbone gas transmission, delivery (local transmission and distribution), and storage services as separate and distinct services to its noncore customers. These customers may elect to receive storage services from the Utility or other third-party storage providers. Noncore customers formerly were able to subscribe for natural gas bundled service as if they were core customers but are no longer allowed to do so. Access to the Utility's backbone gas transmission system is available for all natural gas marketers and shippers, as well as noncore customers.

The Utility has regulatory balancing accounts for core customers designed to ensure that the Utility's results of operations over the long term are not affected by weather variations, conservation or changes in their consumption levels. The Utility's results of operations can, however, be affected by noncore consumption levels because there are fewer regulatory balancing accounts related to noncore customers. Approximately 97% of the Utility's natural gas distribution base revenues are recovered from core customers and 3% are recovered from noncore customers.

The California Gas Report is prepared by the California electric and natural gas utilities to present an outlook for natural gas requirements and supplies for California over a long-term planning horizon. It is prepared in even-numbered years followed by a supplemental report in odd-numbered years. The 2006 California Gas Report forecasts average annual growth in the Utility's natural gas deliveries (for core customers and non-core transportation) of approximately 1.3% for the years 2006 through 2025. The natural gas requirements forecast is subject to many uncertainties, and there are many factors that can influence the demand for natural gas, including weather conditions, level of economic activity, conservation, price, and the number and location of electricity generation facilities.

2006 Natural Gas Deliveries

The following table shows the percentage of the Utility's total 2006 natural gas deliveries represented by each of the Utility's major customer classes:

Total 2006 Natural Gas Deliveries: 836 Bcf

Residential Customers	27%
Transport-only Customers (noncore)	61%
Commercial Customers	12%

Natural Gas Operating Statistics

The following table shows the Utility's operating statistics from 2002 through 2006 (excluding subsidiaries) for natural gas, including the classification of sales and revenues by type of service:

	2006	2005	2004	2003	2002
Customers (average for the year):					
Residential	3,989,331	3,929,117	3,812,914	3,744,011	3,738,524
Commercial	220,024	216,749	215,547	208,857	206,953
Industrial	988	962	2,178	1,988	1,819
Other gas utilities	6	6	6	6	5
Total	4,210,349	4,146,834	4,030,645	3,954,862	3,947,301
Gas supply (MMcf):					
Purchased from suppliers in:					
Canada	202,274	204,884	205,180	196,278	210,716
California	(13,401)	(18,951)	(9,108)	(7,421)	19,533
Other states	103,658	103,237	103,801	102,941	67,878
Total purchased	292,531	289,170	299,873	291,798	298,127
Net (to storage) from storage	4,359	(3,659)	(532)	1,359	(218)
Total	296,890	285,511	299,341	293,157	297,909
Utility use, losses, etc. [1]	(27,610)	(14,312)	(19,287)	(14,307)	(16,393)

Net gas for sales	269,280	271,199	280,054	278,850	281,516
Bundled gas sales (MMcf):					
Residential	196,092	194,108	201,601	198,580	202,141
Commercial	73,178	77,056	78,080	79,891	78,812
Industrial	10	35	373	379	563
Other gas utilities	___	—	—	—	—
Total	269,280	271,199	280,054	278,850	281,516
Transportation only (MMcf):	559,270	572,869	597,706	525,353	508,090
Revenues (in millions):					
Bundled gas sales:					
Residential	$ 2,452	$ 2,336	$ 1,944	$ 1,836	$ 1,379
Commercial	859	885	712	697	499
Industrial	-	—	—	1	3
Other gas utilities	-	—	—	1	1
Miscellaneous	121	(22)	(29)	(31)	127
Regulatory balancing accounts	40	340	316	68	11
Bundled gas revenues	3,472	3,539	2,943	2,572	2,020
Transportation service only revenue	315	237	270	284	316
Operating revenues	$ 3,787	$ 3,776	$ 3,213	$ 2,856	$ 2,336
Selected Statistics:					
Average annual residential usage (Mcf)	49	49	53	53	54
Average billed bundled gas sales revenues per Mcf:					
Residential	$ 12.50	$ 12.04	$ 9.64	$ 9.25	$ 6.82
Commercial	11.73	11.48	9.12	8.73	6.33
Industrial	1.03	0.61	(0.56)	2.48	4.35
Average billed transportation only revenue per Mcf	0.56	0.42	0.45	0.54	0.62
Net plant investment per customer	$ 1,304	$ 1,262	$ 1,266	$ 1,261	$ 1,006

(1) Includes fuel for the Utility's fossil fuel-fired generation plants.

Natural Gas Supplies

The Utility purchases natural gas to serve the Utility's core customers directly from producers and marketers in both Canada and the United States. The contract lengths and natural gas sources of the Utility's portfolio of natural gas purchase contracts have fluctuated, generally based on market conditions. During 2006, the Utility purchased approximately 293,000 Mcf of natural gas (net of the sale of excess supply) from 68 suppliers. Consistent with existing CPUC policy directives, substantially all this natural gas was purchased under contracts with a term of one year or less. The Utility's largest individual supplier represented approximately 10.7% of the total natural gas volume the Utility purchased during 2006.

The following table shows the total volume and the average price of natural gas in dollars per Mcf of the Utility's natural gas purchases by region during each of the last five years. The average prices for Canadian and U.S. southwest gas shown below include the commodity natural gas prices, pipeline demand or reservation charges, transportation charges and other pipeline assessments. The volumes purchased are shown net of sales of excess supplies of gas. In 2006, the sale of excess supplies to parties located in California exceeded purchases from parties located in California.

	2006		2005		2004		2003		2002	
	MMcf	Avg. Price	MMcf	Avg. Price	MMcf	Avg. Price	MMcf	Avg. Price	MMcf	Avg. Price
Canada	202,274	6.27	204,884	$ 7.12	205,180	$ 5.37	196,278	$ 4.73	210,716	$ 2.42
California (1)	(13,401)	7.04	(18,951)	$ 7.70	(9,108)	$ 4.89	(7,421)	$ 3.39	19,533	$ 2.88
Other states (substantially all U.S. southwest)	103,658	6.51	103,237	$ 7.10	103,801	$ 5.44	102,941	$ 4.63	67,878	$ 3.04
Total/weighted average	292,531	6.32	289,170	$ 7.07	299,873	$ 5.41	291,798	$ 4.73	298,127	$ 2.59

(1) California purchases include supplies from various California producers and supplies transported into California by others.

Gas Gathering Facilities

The Utility's gas gathering system collects natural gas from third-party wells in California. During 2006, approximately 6% of the gas transported on the Utility's system came from various California producers, with the balance coming from supplies transported into California by others. The natural gas well production is processed by producers to remove various impurities from the natural gas stream and the Utility then odorizes the natural gas so that it may be detected in the event of a leak. The facilities include approximately 395.6 miles of gas gathering pipelines. The Utility receives gas well production at approximately 250 metering facilities. The Utility's gas gathering system is geographically dispersed and is located in 13 California counties. Approximately 138 MMcf per day of natural gas produced in northern California was delivered into the Utility's gas gathering system during 2006.

Interstate and Canadian Natural Gas Transportation Services Agreements

In 2006, approximately 62% of the gas transported on the Utility's system came from western Canada. The Utility has a number of arrangements with interstate and Canadian third-party transportation service providers to serve core customers' service demands. The Utility has firm transportation agreements for delivery of natural gas from western Canada to the United States- Canadian border with TransCanada NOVA Gas Transmission, Ltd. and TransCanada PipeLines Ltd., B.C. System. These companies' pipeline systems connect at the border to the pipeline system owned by Gas Transmission Northwest Corporation which provides natural gas transportation services to interconnection points with the Utility's natural gas transportation system in the area of California near Malin, Oregon. The Utility has a firm transportation agreement with Gas Transmission Northwest Corporation for these services.

During 2006, approximately 32% of the gas transported on the Utility's system came from the western United States, excluding California. The Utility has firm transportation agreements with Transwestern Pipeline Co., or Transwestern, and El Paso Natural Gas Company, or El Paso, to transport this natural gas from supply points in this region to interconnection points with the Utility's natural gas transportation system in the area of California near Topock, Arizona. The Utility also has a short-term firm transportation agreement with Kern River Gas Transmission Company to transport this natural gas from supply points in this region to an interconnection point with the Utility's natural gas transportation system at Daggett, California.

The following table shows certain information about the Utility's firm natural gas transportation agreements, including the contract quantities, contract durations and associated demand charges, net of sales of excess supplies, for capacity reservations. These agreements require the Utility to pay fixed demand charges for reserving firm capacity on the pipelines. The total demand charges may change periodically as a result of changes in regulated tariff rates approved by Canadian regulators in the case of TransCanada NOVA Gas Transmission, Ltd. and TransCanada PipeLines Ltd., B.C. System, and by the FERC in all other cases. The Utility may, upon prior notice and with the CPUC's approval, extend each of these natural gas transportation agreements. On the FERC-regulated pipelines, the Utility has either a right of first refusal or evergreen rights allowing it to renew natural gas transportation agreements at the end of their terms. If another prospective shipper also wants the capacity, the Utility would be required to match the competing bid with respect to both price and term.

Pipeline	Expiration Date	Quantity MDth per day	Demand Charges for the Year Ended December 31, 2006 (In millions)
TransCanada NOVA Gas Transmission, Ltd.	12/31/2008[a]	619	25.2
TransCanada PipeLines Ltd., B.C. System	10/31/2008	611	14.3
Gas Transmission Northwest Corporation	10/31/2008	610	56.1
Transwestern Pipeline Co.	03/31/2010	150	19.9
El Paso Natural Gas Company (b)	Various	252	17.2
Kern River Gas Transmission Company	2/28/2007	29	0.4

(a) A small portion (23 MDth/d) of the Utility's capacity is due to expire on October 31, 2008.

(b) As of December 31, 2006, the Utility has four active contracts with El Paso with expiration dates ranging from February 28, 2007 to June 30, 2010.

Environmental Matters

The following discussion includes certain forward-looking information relating to estimated expenditures for environmental protection measures and the possible future impact of environmental compliance. The information below reflects current estimates that are periodically evaluated and revised. Future estimates and actual results may differ materially from those indicated below. These estimates are subject to a number of assumptions and uncertainties, including changing laws and regulations, the ultimate outcome of complex factual investigations, evolving technologies, selection of compliance alternatives, the nature and extent of required remediation, the extent of the facility owner's responsibility, and the availability of recoveries or contributions from third parties.

General

The Utility is subject to a number of federal, state and local laws and requirements relating to the protection of the environment and the safety and health of the Utility's personnel and the public. These laws and requirements relate to a broad range of activities, including:

- the discharge of pollutants into air, water and soil;
- the identification, generation, storage, handling, transportation, treatment, disposal, record keeping, labeling, reporting of, remediation of and emergency response in connection with hazardous and radioactive substances; and
- land use, including endangered species and habitat protection.

The penalties for violation of these laws and requirements can be severe, and may include significant fines, damages and criminal or civil sanctions. These laws and requirements also may require the Utility, under certain circumstances, to interrupt or curtail operations. To comply with these laws and requirements, the Utility may need to spend substantial amounts from time to time to construct, acquire, modify or replace equipment, acquire permits and/or marketable allowances or other emission credits for facility operations and clean-up or decommission waste disposal areas at the Utility's current or former facilities and at third-party sites where the Utility may have disposed of wastes.

Generally, the Utility has recovered the costs of complying with environmental laws and regulations in the Utility's rates, subject to reasonableness review. Environmental costs associated with the clean-up of sites that contain hazardous substances are subject to a special ratemaking mechanism under which the Utility is authorized to recover hazardous waste remediation costs for environmental claims (e.g . , for cleaning up the Utility's facilities and sites where the Utility has sent hazardous substances) from customers. This mechanism allows the Utility to include 90% of the hazardous waste remediation costs in the Utility's rates without a reasonableness review. Ten percent of any net insurance recoveries associated with hazardous waste remediation sites is assigned to the Utility's customers. The balance of any insurance recoveries (90%) is retained by the Utility until it has been reimbursed for the 10% share of clean-up costs not included in rates. Any insurance recoveries above full cost reimbursement levels would then be allocated 60% to customers and 40% to the Utility. Finally, 10% of any recoveries from the Utility's claims against third parties associated with hazardous waste remediation sites is retained by the Utility; 90% of any such recoveries is assigned to the Utility's customers.

Hazardous waste remediation costs are rising and likely to be significant into the foreseeable future. Based on the Utility's past experience, it believes that it can recover most of the future costs that it may incur to remediate hazardous waste through rates and insurance recoveries. The Utility cannot provide assurance, however, that these costs will not be material, or that the Utility will be able to recover its costs in the future.

Air Quality and Climate Change

The Utility's electricity generation plants, natural gas pipeline operations, fleet and fuel storage tanks are subject to numerous air pollution control laws, including the federal Clean Air Act and similar state and local statutes. These laws and regulations cover, among other pollutants, those contributing to the formation of ground-level ozone, carbon monoxide, sulfur dioxide, nitrogen oxide and particulate matter. Fossil fuel-fired electric utility plants and gas compressor stations used in the Utility's pipeline operations are sources of air pollutants and, therefore, are subject to substantial regulation and enforcement oversight by the applicable governmental agencies. The Utility's existing and forecast emissions of greenhouse gases are relatively low compared to average emissions by other electric utilities and generators in the country.

In addition, various laws and regulations addressing climate change are being considered or implemented at the federal and state levels. At the federal level, several legislative initiatives have been introduced recently in Congress aimed at addressing climate change through imposition of nation-wide regulatory limits on the emissions of greenhouse gases. No such legislation has yet been enacted by Congress, but extensive hearings and discussion is expected in the coming year.

At the state level, in 2006 California enacted Assembly Bill 32, the California Global Warming Solutions Act of 2006, to address climate change. The law establishes a regulatory program and schedule to gradually reduce greenhouse gas emissions in California to 1990 levels by 2020. By January 1, 2008, this law requires the CARB to determine what the state-wide greenhouse gas emission level was in 1990, approve a statewide greenhouse gas emissions limit, and adopt regulations to require significant greenhouse gas emitters, including utilities and other load-serving entities, to submit annual greenhouse gas emissions reports that have been verified or certified by the CARB. Assembly Bill 32 also authorizes the CARB to monitor and enforce compliance with the greenhouse gas reduction program and to consider implementing market-based mechanisms, including trading of greenhouse gas emissions allowances.

In addition to Assembly Bill 32, California Senate Bill 1368, enacted in September 2006, prohibits any load-serving entity in California, including investor-owned electric utilities, from entering into a long-term financial commitment for baseload electricity generation unless the generation complies with a greenhouse gas emission performance standard. As required by Senate Bill 1368, on January 25, 2007, the CPUC adopted an interim greenhouse gas emissions performance standard of 1,100 pounds of carbon dioxide per MWh that applies to new commitments for baseload electricity procured under contracts with a term of five years or longer or generated by the Utility. After an enforceable state-wide greenhouse gas emissions limit is established and in operation in accordance with Assembly Bill 32, the CPUC will re-evaluate its interim greenhouse gas emissions performance standard and determine whether to continue, modify or rescind it.

The new California legislation, as well as current federal and other state regulatory initiatives relating to emissions of carbon dioxide and other greenhouse gases, particulates and other pollutants, could cause the Utility's compliance costs and capital expenditures to increase. These laws could require the Utility to replace equipment, install additional pollution controls, purchase various emission allowances or curtail operations. Although associated costs and capital expenditures could be material, the Utility expects that it will recover these costs and capital expenditures in rates consistent with the recovery of other reasonable costs of complying with environmental laws and regulations.

The CARB also oversees the Periodic Smoke Inspection Program to test and repair heavy-duty diesel vehicles in order to ensure efficient operations and reduce particulate matter emissions. The program applies to approximately 2,000 vehicles owned by the Utility. In July 2006, the CARB requested the Utility's program compliance records. The Utility discovered that its records were incomplete and that some records could not be located. The Utility immediately notified the CARB and began the evaluation and implementation of process improvements to ensure accurate recordkeeping. The CARB is authorized to assess penalties of up to $500 per missing or incomplete record. The Utility continues to work with the CARB and expects to resolve the matter in the first quarter of 2007. The Utility believes that the ultimate outcome of this matter would not result in a material adverse effect on its financial condition or results of operations.

Water Quality

The Utility's Diablo Canyon power plant employs a “once-through” cooling water system that is regulated under a Clean Water Act National Pollutant Discharge Elimination System, or NPDES, permit issued by the Central Coast Regional Water Quality Control Board, or the Central Coast Board. This permit allows the Diablo Canyon power plant to discharge the cooling water at a temperature no more than 22 degrees above the temperature of the ambient receiving water, and requires that the beneficial uses of the

water be protected. The beneficial uses of water in this region include industrial water supply, marine and wildlife habitat, shellfish harvesting, and preservation of rare and endangered species. In January 2000, the Central Coast Board issued a proposed draft cease and desist order alleging that, although the temperature limit has never been exceeded, the Diablo Canyon power plant's discharge was not protective of beneficial uses.

In October 2000, the Utility and the Central Coast Board reached a tentative settlement under which the Central Coast Board agreed to find that the Utility's discharge of cooling water from the Diablo Canyon power plant protects beneficial uses and that the intake technology reflects the best technology available, as defined in the federal Clean Water Act. As part of the tentative settlement, the Utility agreed to take measures to preserve certain acreage north of the plant and to fund approximately $6 million in environmental projects and future environmental monitoring related to coastal resources. On March 21, 2003, the Central Coast Board voted to accept the settlement agreement. On June 17, 2003, the settlement agreement was executed by the Utility, the Central Coast Board and the California Attorney General's Office. A condition to the effectiveness of the settlement agreement is that the Central Coast Board renew Diablo Canyon's NPDES permit.

At its July 10, 2003 meeting, the Central Coast Board did not renew the NPDES permit and continued the permit renewal hearing indefinitely. Several Central Coast Board members indicated that they no longer supported the settlement agreement, and the Central Coast Board requested a team of independent scientists, as part of a technical working group, to develop additional information on possible mitigation measures for Central Coast Board staff. In January 2005, the Central Coast Board published the scientists' draft report recommending several such mitigation measures. If the Central Coast Board adopts the scientists' recommendations, and if the Utility ultimately is required to implement the projects proposed in the draft report, it could incur costs of up to approximately $30 million. The Utility would seek to recover these costs through rates charged to customers.

In addition, on July 9, 2004, the U.S. Environmental Protection Agency, or the EPA, published regulations under Section 316(b) of the Clean Water Act for cooling water intake structures. The regulations affect existing electricity generation facilities using over 50 million gallons per day, typically including some form of “once-through” cooling. The Diablo Canyon power plant is among an estimated 539 generation facilities nationwide that are affected by this rulemaking. The Utility permanently closed its Hunters Point power plant in May 2006 and the Humboldt Bay power plant will be re-powered without the use of once-through cooling. The EPA regulations establish a set of performance standards that vary with the type of water body and that are intended to reduce impacts to aquatic organisms. Significant capital investment may be required to achieve the standards. The regulations allow site-specific compliance determinations if a facility's cost of compliance is significantly greater than either the benefits achieved or the compliance costs considered by the EPA, and also allow the use of environmental mitigation or restoration to meet compliance requirements in certain cases. Various parties challenged the EPA’s regulations and the cases were consolidated in the U.S. Court of Appeal for the Second Circuit, or Second Circuit.

In June 2006, the California State Water Resources Control Board published a draft policy for California’s implementation of Section 316(b). If adopted, the draft policy would be substantially more stringent than the 2004 EPA regulations as the state policy would eliminate the EPA’s site-specific compliance options based on cost-benefit assessments and essentially requires the installation of cooling towers at once-through cooled power facilities. The draft policy provides that nuclear facilities may use environmental restoration as a compliance option only if the installation of technology would conflict with a nuclear safety requirement. It is uncertain when the state’s final policy will be adopted. If the final policy is adopted without change from the draft policy, the Utility could be required to incur significant capital costs to achieve compliance.

On January 25, 2007, the Second Circuit issued its decision on the appeals of the EPA Section 316(b) regulations. The Second Circuit remanded significant provisions of the regulations to EPA for reconsideration and held that a cost benefit test cannot be used to establish performance standards or to grant variances from the standards. The Second Circuit also ruled that environmental restoration cannot be used to achieve compliance. The parties may seek either en banc review by the Second Circuit or review by the U.S. Supreme Court. Regardless of whether the decision is subject to further judicial review, the EPA will likely require significant time to review and revise the regulations. It is uncertain how the Second Circuit decision will affect development of the state’s proposed implementation policy. The regulatory uncertainty is likely to continue and the Utility’s cost of compliance, while likely to be significant, will remain uncertain as well.

Groundwater at the Utility’s Hinkley and Topock natural gas compressor stations contains hexavalent chromium as a result of the Utility’s past operating practices. The Utility has a comprehensive program to monitor a network of groundwater wells at both the Hinkley and Topock natural gas compressor stations. At Hinkley, the Utility is cooperating with the Regional Water Quality Control Board to evaluate and remediate the chromium groundwater plume. In 2006, the Utility took interim measures to control movement of the Hinkley plume, as well as evaluated options to remediate the plume. At the Topock gas compressor station, located near Needles, California, adjacent to the Colorado River, hexavalent chromium has been detected in samples taken from groundwater monitoring wells located approximately 65 feet from the Colorado River. The Utility is cooperating with the California Department of Toxic Substances Control, other state agencies, appropriate federal agencies and other interested parties, to implement interim

measures as well as develop a long-term plan to ensure that the hexavalent chromium does not affect the Colorado River. In 2006, the Utility took interim measures to control the chromium plume by extracting impacted groundwater and spent approximately $17 million on these measures. The Utility plans to continue these activities in 2007 and to work toward the development of a final plan to address the plume in 2007. The Utility currently estimates that it will spend at least $20 million in 2007 for remediation activities at Topock and $22 million in 2007 for remediation activities at Hinkley. Although work at the Topock site poses several technical and regulatory obstacles, the Utility's remediation costs for Topock are subject to the ratemaking mechanism described above. The Utility does not expect the remediation of the Topock and Hinkley gas compressor sites to have a material adverse effect on its results of operations or financial condition. The Utility does not expect that it will incur any material expenditures related to any remediation at its Kettleman natural gas compressor station.

Compressor Station Litigation

Several lawsuits have been filed against the Utility alleging that exposure to chromium at or near the Utility's natural gas compressor stations caused personal injuries, wrongful deaths or other injuries. During 2006, the Utility entered into a settlement agreement to resolve most of these claims. Pursuant to the settlement agreement, in April 2006, the Utility released $295 million from escrow for payment to approximately 1,100 plaintiffs. There are three complaints filed by approximately 125 plaintiffs who did not participate in the settlement that are still pending in the Superior Court for the County of Los Angeles. With respect to the unresolved claims, the Utility will continue to pursue appropriate defenses, including the statute of limitations, the exclusivity of workers' compensation laws, lack of exposure to chromium and the inability of chromium to cause certain of the illnesses alleged. PG&E Corporation and the Utility do not expect that the outcome with respect to the remaining unresolved claims will have a material adverse effect on their financial condition or results of operations.

Endangered Species

Many of the Utility's facilities and operations are located in or pass through areas that are designated as critical habitats for federal or state-listed endangered, threatened or sensitive species. The Utility may be required to incur additional costs or be subjected to additional restrictions on operations if additional threatened or endangered species are listed or additional critical habitats are designated near the Utility's facilities or operations. The Utility is seeking to secure "habitat conservation plans" to ensure long-term compliance with the state and federal endangered species acts. The Utility expects that it will be able to recover costs of complying with state and federal endangered species acts through rates.

Hazardous Waste Compliance and Remediation

The Utility's facilities are subject to the requirements issued by the EPA under the Resource Conservation and Recovery Act, or RCRA, and the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended, or CERCLA, as well as other state hazardous waste laws and other environmental requirements. CERCLA and similar state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, damages to natural resources and the costs of required health studies. In the ordinary course of the Utility's operations, the Utility generates waste that falls within CERCLA's definition of a hazardous substance and, as a result, has been and may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

The Utility assesses, on an ongoing basis, measures that may be necessary to comply with federal, state and local laws and regulations related to hazardous materials and hazardous waste compliance and remediation activities. The Utility has a comprehensive program to comply with hazardous waste storage, handling and disposal requirements issued by the EPA under RCRA and CERCLA, state hazardous waste laws and other environmental requirements.

The Utility has been, and may be, required to pay for environmental remediation at sites where the Utility has been, or may be, a potentially responsible party under CERCLA and similar state environmental laws. These sites include former manufactured gas plant sites, power plant sites, gas gathering sites, compressor stations and sites where the Utility stores, recycles and disposes of potentially hazardous materials. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if it did not deposit those substances on the site.

Operations at the Utility's current and former generation facilities may have resulted in contaminated soil or groundwater. Although the Utility sold most of its geothermal generation facilities and most of its fossil fuel-fired plants, in many cases the Utility retained pre-closing environmental liability under various environmental laws. The Utility currently is investigating or remediating

several such sites with the oversight of various governmental agencies.

In addition, the federal Toxic Substances Control Act regulates the use, disposal and clean-up of polychlorinated biphenyls, or PCBs, which are used in certain electrical equipment. The Utility has removed from service all of the distribution capacitors and network transformers containing high concentrations of PCBs, the vast majority of PCBs existing in the Utility's electricity distribution system.

The Utility is assessing whether and to what extent remedial action may be necessary to mitigate potential hazards posed by certain disposal sites and retired manufactured gas plant sites. During their operation from the mid-1800s through the early 1900s, manufactured gas plants produced lampblack and tar residues. The residues that may remain at some sites contain chemical compounds that now are classified as hazardous. The Utility owns all or a portion of 28 manufactured gas plant sites. The Utility has a program, in cooperation with environmental agencies, to evaluate and take appropriate action to mitigate any potential health or environmental hazards at these sites. The Utility spent approximately $3 million in 2006 and expects to spend approximately $6 million in 2007 on these projects. The Utility expects that expenses will increase as remedial actions related to these sites are approved by regulatory agencies. There are approximately 67 other manufactured gas plant sites in the Utility's service territory that are now owned by others which remain a source of potential claims. It is likely that the Utility will incur remediation costs related to some of these sites. Although the Utility has been able to quantify potential liability for many of these sites, the amount of potential liability for all of these sites cannot be quantified.

Under environmental laws such as CERCLA, the Utility has been or may be required to take remedial action at third-party sites used for the disposal of waste from the Utility's facilities, or to pay for associated clean-up costs or natural resource damages. The Utility is currently aware of eight such sites where investigation or clean-up activities are currently underway. At the Geothermal Incorporated site in Lake County, California, the Utility is in the process of completing a three-year closure of the disposal facility which was abandoned by its operator. The Utility was the major responsible party and led this effort on behalf of the responsible parties. In 2006, the Utility completed settlements with the other responsible parties for their share of future costs and assumed ownership of the closed facility. At the Casmalia disposal facility near Santa Maria, California, the Utility and several other generators of waste sent to the site have entered into a court-approved agreement with the EPA that requires the Utility and the other parties to perform certain site investigation and mitigation measures.

In addition, the Utility has been named as a defendant in several civil lawsuits in which plaintiffs allege that the Utility is responsible for performing or paying for remedial action at sites that it no longer owns or never owned. Remedial actions may include investigations, health and ecological assessments, and removal of wastes.

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. The Utility estimates the upper end of this cost range using reasonably possible outcomes that are least favorable to the Utility. It is reasonably possible that a change in these estimates may occur in the near term due to uncertainty concerning the Utility's responsibility, the complexity of environmental laws and regulations, and the selection of compliance alternatives.

The Utility had an undiscounted environmental remediation liability of approximately $511 million at December 31, 2006 and approximately $469 million at December 31, 2005. The increase in the undiscounted environmental remediation reflects an increase of $74 million for remediation at the Utility’s gas compressor stations located near Hinkley, California and Topock, Arizona. The portion of the increased liability of $39 million for remediation at the Hinkley facility is attributable to changes in the California Regional Water Quality Control Board’s imposed remediation levels. Costs incurred at this facility are not recoverable from customers and, as a result, the after-tax impact on income was a reduction of approximately $23 million for 2006. Ninety percent of the estimated remediation costs associated with the Utility’s gas compressor station located near Topock, Arizona will be recoverable in rates in accordance with the hazardous waste ratemaking mechanism which permits the Utility to recover ninety percent of hazardous waste remediation costs from customers without a reasonableness review.

For more information about environmental remediation liabilities, see Note 17 of the Notes to the Consolidated Financial Statements in the 2006 Annual Report.

Nuclear Fuel Disposal

Under the Nuclear Waste Policy Act of 1982, the Department of Energy, or the DOE, is responsible for the transportation and permanent storage and disposal of spent nuclear fuel and high-level radioactive waste. The Utility has contracted with the DOE to provide for the disposal of these materials from Diablo Canyon. Under the contract, if the DOE completes a storage facility by 2010, the earliest that Diablo Canyon's spent fuel would be accepted for storage or disposal is thought to be 2018. Under current operating procedures, the Utility believes that the existing spent fuel pools (which include newly constructed temporary storage racks) have sufficient capacity to enable the Utility to operate Diablo Canyon until approximately 2010 for Unit 1 and 2011 for Unit 2. After receiving a permit from the NRC in March 2004, the Utility began building an on-site dry cask storage facility to store spent fuel through at least 2024. T he Utility estimates it could complete the dry cask storage project in 2008. The NRC's March 2004 decision, however, was appealed by various parties, and the U.S. Court of Appeals for the Ninth Circuit, or Ninth Circuit, issued a decision in 2006 that requires the NRC to consider the environmental consequences of a potential terrorist attack at Diablo Canyon as part of the NRC's supplemental assessment of the dry cask storage permit. The Utility may incur significant additional expenditures if the NRC decides that the Utility must change the design and construction of the dry cask storage facility. If the Utility is unable to complete the dry cask storage facility, or if construction is delayed beyond 2010, and if the Utility is otherwise unable to increase its on-site storage capacity, it is possible that the operation of Diablo Canyon may have to be curtailed or halted as early as 2010 with respect to Unit 1 and 2011 with respect to Unit 2 and until such time as additional spent fuel can be safely stored.

As a result of the DOE's failure to develop a permanent storage facility, the Utility has been required to incur substantial costs for planning and developing on-site storage options for spent nuclear fuel as described above at Diablo Canyon as well as at the retired nuclear facility at Humboldt Bay, or Humboldt Bay Unit 3. The Utility is seeking to recover these costs from the DOE on the basis that the DOE has breached its contractual obligation to move used nuclear fuel from Diablo Canyon and Humboldt Bay Unit 3 to a national repository beginning in 1998. Any amounts recovered from the DOE will be credited to customers. In October 2006, the U.S. Court of Federal Claims issued a decision awarding approximately $42.8 million of the $92 million incurred by the Utility through 2004. The Utility will seek recovery of costs incurred after 2004 in future lawsuits against the DOE. In January 2007, the Utility filed a notice of appeal of the U.S. Court of Federal Claims' decision in the U.S. Court of Appeals for the Federal Circuit seeking to increase the amount of the award and challenging the court's finding the Utility would have had to incur some of the costs for the onsite storage facilities even if the DOE had complied with the contract. If the court's decision is not overturned or modified on appeal, it is likely that the Utility will be unable to recover all of its future costs for onsite storage facilities from the DOE. However, reasonably incurred costs related to the onsite storage facilities are, in the case of Diablo Canyon, recoverable through rates and, in the case of Humboldt Bay Unit 3, recoverable through its decommissioning trust fund.

PG&E Corporation and the Utility are unable to predict the outcome of this appeal or the amount of any additional awards the Utility may receive.

Nuclear Decommissioning

The Utility's nuclear power facilities consist of two units at Diablo Canyon and the retired facility at Humboldt Bay Unit 3. Nuclear decommissioning requires the safe removal of nuclear facilities from service and the reduction of residual radioactivity to a level that permits termination of the NRC license and release of the property for unrestricted use. For ratemaking purposes, the eventual decommissioning of Diablo Canyon Unit 1 is scheduled to begin in 2024 and to be completed in 2044. Decommissioning of Diablo Canyon Unit 2 is scheduled to begin in 2025 and to be completed in 2041, and decommissioning of Humboldt Bay Unit 3 is scheduled to begin in 2009 and to be completed in 2015. The Utility's revenue requirements for estimated nuclear decommissioning costs are recovered from customers through a non-bypassable charge that will continue until those costs are fully recovered. The decommissioning cost estimates are based on the plant location and cost characteristics for the Utility's nuclear power plants. Actual decommissioning costs may vary from these estimates as a result of changes in assumptions such as decommissioning dates, regulatory requirements, technology, and costs of labor, materials and equipment. For more information about nuclear decommissioning, including the estimated decommissioning costs, see Note 13 of the Notes to the Consolidated Financial Statements in the 2006 Annual Report.

Electric and Magnetic Fields

Electric and magnetic fields, or EMFs, naturally result from the generation, transmission, distribution and use of electricity. In November 1993, the CPUC adopted an interim EMF policy for California energy utilities that, among other things, requires California energy utilities to take no-cost and low-cost steps to reduce EMFs from new or upgraded utility facilities. California energy utilities were required to fund an EMF education program and an EMF research program managed by the California Department of Health Services. In October 2002, the California Department of Health Services released its report, based primarily on its review of studies by others, evaluating the possible risks from EMFs, to the CPUC and the public. The report's conclusions contrast with other

recent reports by authoritative health agencies in that the California Department of Health Services' report has assigned a higher probability to the possibility of a causal connection between EMF exposures and a number of diseases and conditions, including childhood leukemia, adult leukemia, amyotrophic lateral sclerosis and miscarriages.

On January 26, 2006, the CPUC issued a decision which affirms the CPUC's "low-cost/no-cost, prudent avoidance" policy to reduce EMF exposure for new utility transmission and substation projects. The CPUC ordered the continued use of a 4% of project cost benchmark for EMF reduction measures. The CPUC also reaffirmed that it has exclusive jurisdiction with respect to utility EMF matters.

The Utility currently is not involved in third-party litigation concerning EMFs. In August 1996, the California Supreme Court held that homeowners are barred from suing utilities for alleged property value losses caused by fear of EMFs from power lines. In a case involving allegations of personal injury, a California appeals court held that the CPUC has exclusive jurisdiction over personal injury and wrongful death claims arising from allegations of harmful exposure to EMFs and barred plaintiffs' personal injury claims. The California Supreme Court declined to hear the plaintiffs' appeal of this decision.

Item 1A. ***Risk Factors***

A discussion of the significant risks associated with investments in the securities of PG&E Corporation and the Utility is set forth under the heading "Risk Factors" in the MD&A in the 2006 Annual Report, which information is hereby incorporated by reference and filed as part of Exhibit 13 to this report.

Item 1B. ***Unresolved Staff Comments***

Not applicable.

Item 2. ***Properties***

The Utility owns or has obtained the right to occupy and/or use real property comprising the Utility's electricity and natural gas distribution facilities, natural gas gathering facilities and generation facilities, and natural gas and electricity transmission facilities, all of which are described above under "Electric Utility Operations" and "Natural Gas Utility Operations" above. In total, the Utility occupies 9.8 million square feet of real property, including 8.5 million square feet that the Utility owns. Of the 9.8 million square feet of occupied real property, approximately 1.7 million square feet represent the Utility's corporate headquarters located in several buildings in San Francisco, California. The Utility leases approximately 120,000 square feet of the approximate 1.7 million square feet of office space. The Utility occupies or uses real property that it does not own primarily through various leases, easements, rights-of-way, permits or licenses from private landowners or governmental authorities. The Utility currently owns approximately 167,000 acres of land, approximately 140,000 acres of which it will encumber with conservation easements and/or donate to public agencies or non-profit conservation organizations under the Chapter 11 Settlement Agreement. Approximately 75,000 acres of this land may be donated in fee and encumbered with conservation easements. The remaining land contains the Utility's or a joint licensee's hydroelectric generation facilities and will only be encumbered with conservation easements. As contemplated in the Chapter 11 Settlement Agreement, the Utility formed an entity, the Pacific Forest Watershed Lands Stewardship Council, or the Council, to oversee the development and implementation of a Land Conservation Plan, or LCP, that will articulate the long-term management objectives for the 140,000 acres. The Council is governed by an 18-member Board of Directors that represent a range of diverse interests, including the CPUC, California environmental agencies, organizations representing underserved and minority constituencies, agricultural and business interests, and public officials. The Utility has appointed 1 out of 18 members of the Board of Directors of the Council. While the Council originally contemplated adopting and presenting the LCP to the Utility by April 2007, it currently anticipates approving the LCP in the summer of 2007. The Utility will then seek authorization from the CPUC, the FERC and other approving entities to proceed with the transactions necessary to implement the LCP. If the Council is unable to reach consensus on all or part of the LCP, the Utility will seek regulatory approval of the transactions required to implement its own plan, along with a description of the positions of the disputing board members, before April 2013.

PG&E Corporation also leases approximately 74,000 square feet of office space from a third party in San Francisco, California. This lease expires in 2012.

Item 3. ***Legal Proceedings***

In addition to the following legal proceedings, PG&E Corporation and the Utility are involved in various legal proceedings in the ordinary course of their business.

Diablo Canyon Power Plant

The Utility's Diablo Canyon power plant employs a “once-through” cooling water system that is regulated under a Clean Water Act National Pollutant Discharge Elimination System, or NPDES, permit issued by the Central Coast Regional Water Quality Control Board, or the Central Coast Board. This permit allows the Diablo Canyon power plant to discharge the cooling water at a temperature no more than 22 degrees above the temperature of the ambient receiving water, and requires that the beneficial uses of the water be protected. The beneficial uses of water in this region include industrial water supply, marine and wildlife habitat, shellfish harvesting, and preservation of rare and endangered species. In January 2000, the Central Coast Board issued a proposed draft cease and desist order alleging that, although the temperature limit has never been exceeded, the Utility's Diablo Canyon power plant's discharge was not protective of beneficial uses.

In October 2000, the Utility and the Central Coast Board reached a tentative settlement under which the Central Coast Board agreed to find that the Utility's discharge of cooling water from the Diablo Canyon power plant protects beneficial uses and that the intake technology reflects the best technology available, as defined in the federal Clean Water Act. As part of the tentative settlement, the Utility agreed to take measures to preserve certain acreage north of the plant and to fund approximately $6 million in environmental projects and future environmental monitoring related to coastal resources. On March 21, 2003, the Central Coast Board voted to accept the settlement agreement. On June 17, 2003, the settlement agreement was executed by the Utility, the Central Coast Board and the California Attorney General's Office. A condition to the effectiveness of the settlement agreement is that the Central Coast Board renew Diablo Canyon's NPDES permit.

At its July 10, 2003 meeting, the Central Coast Board did not renew the NPDES permit and continued the permit renewal hearing indefinitely. Several Central Coast Board members indicated that they no longer supported the settlement agreement, and the Central Coast Board requested a team of independent scientists, as part of a technical working group, to develop additional information on possible mitigation measures for Central Coast Board staff. In January 2005, the Central Coast Board published the scientists' draft report recommending several such mitigation measures. If the Central Coast Board adopts the scientists' recommendations, and if the Utility ultimately is required to implement the projects proposed in the draft report, it could incur costs of up to approximately $30 million. The Utility would seek to recover these costs through rates charged to customers.

PG&E Corporation and the Utility believe that the ultimate outcome of this matter will not have a material adverse impact on their Utility's financial condition or results of operations.

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

On January 10, 2002, the California Attorney General filed a complaint in the Superior Court for the County of San Francisco, or the Superior Court, against PG&E Corporation and its directors, as well as against directors of the Utility, based on allegations of unfair or fraudulent business acts or practices in violation of California Business and Professions Code Section 17200, or Section 17200. Among other allegations, the California Attorney General alleged that past transfers of funds from the Utility to PG&E Corporation during the period from 1997 through 2000 (primarily in the form of dividends and stock repurchases), and allegedly from PG&E Corporation to other affiliates of PG&E Corporation, violated various conditions established by the CPUC in decisions approving the holding company formation. The California Attorney General alleged that the defendants violated these conditions when PG&E Corporation allegedly failed to provide adequate financial support to the Utility during the California energy crisis.

The complaint seeks injunctive relief, the appointment of a receiver, restitution in an amount according to proof, civil penalties of $2,500 against each defendant for each violation of Section 17200, a total penalty of not less than $500 million and costs of suit. The California Attorney General's complaint also seeks restitution of assets allegedly wrongfully transferred to PG&E Corporation from the Utility.

On February 11, 2002, a complaint entitled *City and County of San Francisco; People of the State of California v. PG&E Corporation, and Does 1-150* , was filed in the Superior Court. The complaint contains some of the same allegations contained in the California Attorney General's complaint, including allegations of unfair competition in violation of Section 17200. In addition, the complaint alleges causes of action for conversion, claiming that PG&E Corporation “took at least $5.2 billion from the Utility,” and for unjust enrichment. The City and County of San Francisco, or CCSF, seeks injunctive relief, the appointment of a receiver, restitution, disgorgement, the imposition of a constructive trust, civil penalties of $2,500 against each defendant for each violation of Section 17200 and costs of suit.

The complaints, which have been consolidated in the Superior Court, were filed after the CPUC issued two decisions in its investigative proceeding commenced in April 2001 into whether the California investor-owned electric utilities, including the Utility, complied with past CPUC decisions, rules and orders authorizing their holding company formations and/or governing affiliate transactions, as well as applicable statutes. The order states that the CPUC would, among other matters, investigate the utilities' transfer of money to their holding companies, including during times when their utility subsidiaries were experiencing financial difficulties, the failure of the holding companies to financially assist the utilities when needed, the transfer by the holding companies of assets to unregulated subsidiaries, and the holding companies' actions to "ringfence" their unregulated subsidiaries. In May 2005, the CPUC closed this investigation without making any findings.

PG&E Corporation believes that the intercompany transactions challenged by the California Attorney General and CCSF were in full compliance with applicable law and CPUC conditions. The challenged transactions forming the bulk of the restitution claims were regular quarterly dividends and stock repurchases. As part of its annual cost of capital proceedings, the Utility advised the CPUC in advance of its forecast stock repurchases and dividends. The CPUC did not challenge or question those payments.

In January 2006, the U.S. Court of Appeals for the Ninth Circuit, or the Ninth Circuit, issued a decision on the parties' appeals of various rulings by the Bankruptcy Court and the U.S. District Court for the Northern District of California, or the District Court, concerning jurisdictional issues. The Ninth Circuit found that the Superior Court had jurisdiction over the California Attorney General's and CCSF's restitution claims. (In October 2006, the U.S. Supreme Court declined to grant PG&E Corporation's request to review the Ninth Circuit's decision.) The Ninth Circuit did not address the California Attorney General's and CCSF's underlying allegations that PG&E Corporation and the other defendants violated Section 17200. The Ninth Circuit also did not decide the issue of who would be entitled to receive the proceeds, if any, of a restitution award, and PG&E Corporation continues to believe that any such proceeds would be the property of the Utility. Pursuant to the Chapter 11 Settlement Agreement, the CPUC released all claims against PG&E Corporation or the Utility arising out of or in any way related to the energy crisis, including the CPUC's investigation into past PG&E Corporation actions during the energy crisis. Accordingly, PG&E Corporation believes that any claims for such proceeds by the CPUC would be precluded.

While the Ninth Circuit appeal was pending, the Superior Court held a trial in December 2004 to consider the appropriate standard to determine what constitutes a separate violation of Section 17200 in order to determine the magnitude of potential penalties under Section 17200 (up to $2,500 per separate "violation"). The Superior Court did not address the question of whether any violations occurred. In March 2005, the Superior Court issued a decision rejecting the "per victim" and "per [customer] bill" approaches advocated by the plaintiffs, standards that potentially could have resulted in millions of separate "violations." The Superior Court found that the appropriate standard was each transfer of money from the Utility to PG&E Corporation that plaintiffs allege violated Section 17200. In July 27, 2005, the California Court of Appeal summarily denied a petition filed by the California Attorney General and CCSF seeking to overturn this decision. The California Attorney General and CCSF have resumed discovery in the Superior Court action. The next case management conference is scheduled for April 17, 2007.

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

The California Air Resources Board

The CARB oversees the Periodic Smoke Inspection Program to test and repair heavy-duty diesel vehicles in order to ensure efficient operations and reduce particulate matter emissions. The program applies to approximately 2,000 vehicles owned by the Utility. In July 2006, the CARB requested the Utility's program compliance records. The Utility discovered that its records were incomplete and that some records could not be located. The Utility immediately notified the CARB and began the evaluation and implementation of process improvements to ensure accurate recordkeeping. The CARB is authorized to assess penalties of up to $500 per missing or incomplete record. The Utility continues to work with the CARB and expects to resolve the matter in the first quarter of 2007. The Utility believes that the ultimate outcome of this matter would not result in a material adverse effect on its financial condition or results of operations.

Item 4. ***Submission of Matters to a Vote of Security Holders***

Not applicable.

EXECUTIVE OFFICERS OF THE REGISTRANTS

The names, ages and positions of PG&E Corporation "executive officers," as defined by Rule 3b-7 of the General Rules and Regulations under the Securities and Exchange Act of 1934, or Exchange Act, at February 1, 2007, are as follows:

Name	Age	Position
Peter A. Darbee	54	Chairman of the Board, Chief Executive Officer and President
Leslie H. Everett	56	Senior Vice President, Communications and Public Affairs
Kent M. Harvey	48	Senior Vice President and Chief Risk and Audit Officer
Russell M. Jackson	49	Senior Vice President, Human Resources
Christopher P. Johns	46	Senior Vice President, Chief Financial Officer and Treasurer
Thomas B. King	45	Senior Vice President; Chief Executive Officer, Pacific Gas and Electric Company
Hyun Park	45	Senior Vice President and General Counsel
Rand L. Rosenberg	53	Senior Vice President, Corporate Strategy and Development

All officers of PG&E Corporation serve at the pleasure of the Board of Directors. During the past five years through February 1, 2007, the executive officers of PG&E Corporation had the following business experience. Except as otherwise noted, all positions have been held at PG&E Corporation.

Name	Position	Period Held Office
Peter A. Darbee	Chairman of the Board, Chief Executive Officer and President	January 1, 2006 to present
	Chairman of the Board, Pacific Gas and Electric Company	January 1, 2006 to present
	President and Chief Executive Officer	January 1, 2005 to December 31, 2005
	Senior Vice President and Chief Financial Officer	September 20, 1999 to December 31, 2004
Leslie H. Everett	Senior Vice President, Communications and Public Affairs	January 9, 2006 to present
	Senior Vice President and Assistant to the Chief Executive Officer	January 1, 2005 to January 8, 2006
	Senior Vice President and Assistant to the Chairman	August 2, 2004 to December 31, 2004
	Vice President and Assistant to the Chairman	June 1, 2001 to August 1, 2004
Kent M. Harvey	Senior Vice President and Chief Risk and Audit Officer	October 1, 2005 to present
	Senior Vice President, Chief Financial Officer and Treasurer, Pacific Gas and Electric Company	November 1, 2000 to September 30, 2005
Russell M. Jackson	Senior Vice President, Human Resources, PG&E Corporation and Pacific Gas and Electric Company	August 2, 2004 to present
	Vice President, Human Resources, PG&E Corporation	June 1, 2004 to August 1, 2004
	Vice President, Human Resources, Pacific Gas and Electric Company	June 1, 1999 to August 1, 2004

Christopher P. Johns	Senior Vice President, Chief Financial Officer and Treasurer	October 4, 2005 to present
	Senior Vice President, Chief Financial Officer and Treasurer, Pacific Gas and Electric Company	October 1, 2005 to present
	Senior Vice President, Chief Financial Officer and Controller	January 1, 2005 to October 3, 2005
	Senior Vice President and Controller	September 19, 2001 to December 31, 2004
Thomas B. King	Senior Vice President, PG&E Corporation	January 1, 2006 to present
	Chief Executive Officer, Pacific Gas and Electric Company	August 15, 2006 to present
	President and Chief Executive Officer, Pacific Gas and Electric Company	January 1, 2006 to August 14, 2006
	Executive Vice President and Chief Operating Officer, Pacific Gas and Electric Company	July 1, 2005 to December 31, 2005
	Executive Vice President and Chief of Utility Operations, Pacific Gas and Electric Company	August 2, 2004 to June 30, 2005
	Senior Vice President and Chief of Utility Operations, Pacific Gas and Electric Company	November 1, 2003 to August 1, 2004
	Senior Vice President, PG&E Corporation	January 1, 1999 to October 31, 2003
	President, PG&E National Energy Group, Inc.	November 15, 2002 to July 8, 2003
	President and Chief Operating Officer, PG&E Gas Transmission Corporation	August 27, 2002 to July 8, 2003
	President and Chief Operating Officer, Gas Transmission, PG&E National Energy Group, Inc.	August 9, 2002 to November 14, 2002
	President and Chief Operating Officer, West Region, PG&E National Energy Group, Inc.	July 1, 2000 to August 8, 2002
	President and Chief Operating Officer, PG&E Gas Transmission Corporation	November 23, 1998 to September 10, 2002
Hyun Park	Senior Vice President and General Counsel	November 13, 2006 to present
	Vice President, General Counsel and Secretary, Allegheny Energy, Inc. (an investor-owned utility company headquartered in Pennsylvania)	April 5, 2005 to October 17, 2006
	Senior Vice President, General Counsel and Secretary, Sithe Energies, Inc.	March 2000 to February 2005
Rand L. Rosenberg	Senior Vice President, Corporate Strategy and Development	November 1, 2005 to present
	Executive Vice President and Chief Financial Officer, Infospace, Inc.	September 2000 to January 20, 2001

The names, ages and positions of the Utility's "executive officers," as defined by Rule 3b-7 of the General Rules and Regulations under the Exchange Act at February 1, 2007, are as follows:

Name	Age	Position
Peter A. Darbee	54	Chairman of the Board
Thomas B. King	45	Chief Executive Officer
William. T. Morrow	47	President and Chief Operating Officer
Thomas E. Bottorff	53	Senior Vice President, Regulatory Relations
Jeffrey D. Butler	51	Senior Vice President, Energy Delivery
Leslie H. Everett	56	Senior Vice President, Communications and Public Affairs, PG&E Corporation
Russell M. Jackson	49	Senior Vice President, Human Resources
Christopher P. Johns	46	Senior Vice President, Chief Financial Officer and Treasurer
John S. Keenan	58	Senior Vice President, Generation and Chief Nuclear Officer
Hyun Park	45	Senior Vice President and General Counsel, PG&E Corporation
Stewart M. Ramsay	48	Vice President, Asset Management and Electric Transmission
Fong Wan	45	Vice President, Energy Procurement

All officers of the Utility serve at the pleasure of the Board of Directors. During the past five years through February 1, 2007, the executive officers of the Utility had the following business experience. Except as otherwise noted, all positions have been held at Pacific Gas and Electric Company.

Name	Position	Period Held Office
Peter A. Darbee	Chairman of the Board, Pacific Gas and Electric Company	January 1, 2006 to present
	Chairman of the Board, Chief Executive Officer and President, PG&E Corporation	January 1, 2006 to present
	President and Chief Executive Officer, PG&E Corporation	January 1, 2005 to December 31, 2005
	Senior Vice President and Chief Financial Officer, PG&E Corporation	July 9, 2001 to December 31, 2004
Thomas B. King	Chief Executive Officer	August 15, 2006 to present
	President and Chief Executive Officer	January 1, 2006 to August 14, 2006
	Senior Vice President, PG&E Corporation	January 1, 2006 to present
	Executive Vice President and Chief Operating Officer	July 1, 2005 to December 31, 2005
	Executive Vice President and Chief of Utility Operations	August 2, 2004 to June 30, 2005
	Senior Vice President and Chief of Utility Operations	November 1, 2003 to August 1, 2004
	Senior Vice President, PG&E Corporation	January 1, 1999 to October 31, 2003
	President, PG&E National Energy Group, Inc.	November 15, 2002 to July 8, 2003
	President and Chief Operating Officer, PG&E Gas Transmission Corporation	August 27, 2002 to July 8, 2003
	President and Chief Operating Officer, Gas Transmission, PG&E National Energy Group, Inc.	August 9, 2002 to November 14, 2002
	President and Chief Operating Officer, West Region, PG&E National Energy Group, Inc.	July 1, 2000 to August 8, 2002
	President and Chief Operating Officer, PG&E Gas Transmission Corporation	November 23, 1998 to September 10, 2002
William T. Morrow	President and Chief Operating Officer	August 15, 2006 to present
	Chief Executive Officer, Europe, Vodafone Group PLC (a global mobile telecommunications company)	May 1, 2006 to July 31, 2006
	President, Vodafone KK, Japan	April 1, 2005 to April 30, 2006
	Chief Executive Officer, Vodafone UK, Ltd.	February 1, 2004 to March 31, 2005

	President, Japan Telecom Holdings Co., Inc.	December 21, 2001 to January 31, 2004
Thomas E. Bottorff	Senior Vice President, Regulatory Relations	October 14, 2005 to present
	Senior Vice President, Customer Service and Revenue	March 1, 2004 to October 13, 2005
	Vice President, Customer Service	June 1, 1999 to February 29, 2004
Jeffrey D. Butler	Senior Vice President, Energy Delivery	January 9, 2006 to present
	Senior Vice President, Transmission and Distribution	March 1, 2004 to January 8, 2006
	Vice President, Operations, Maintenance and Construction	June 12, 2000 to February 29, 2004
Leslie H. Everett	Senior Vice President, Communications and Public Affairs, PG&E Corporation	January 9, 2006 to present
	Senior Vice President and Assistant to the Chief Executive Officer, PG&E Corporation	January 1, 2005 to January 8, 2006
	Senior Vice President and Assistant to the Chairman, PG&E Corporation	August 2, 2004 to December 31, 2004
	Vice President and Assistant to the Chairman, PG&E Corporation	June 1, 2001 to August 1, 2004
Russell M. Jackson	Senior Vice President, Human Resources, Pacific Gas and Electric Company and PG&E Corporation	August 2, 2004 to present
	Vice President, Human Resources, PG&E Corporation	June 1, 2004 to August 1, 2004
	Vice President, Human Resources	June 1, 1999 to August 1, 2004
Christopher P. Johns	Senior Vice President, Chief Financial Officer and Treasurer	October 1, 2005 to present
	Senior Vice President, Chief Financial Officer and Treasurer, PG&E Corporation	October 4, 2005 to present
	Senior Vice President, Chief Financial Officer and Controller, PG&E Corporation	January 1, 2005 to October 3, 2005
	Senior Vice President and Controller, PG&E Corporation	September 19, 2001 to December 31, 2004
John S. Keenan	Senior Vice President, Generation and Chief Nuclear Officer	December 19, 2005 to present
	Vice President, Fossil Generation, Progress Energy	November 10, 2003 to December 18, 2005
	Vice President, Brunswick Nuclear Plant, Progress Energy	May 1, 1998 to November 9, 2003
Hyun Park	Senior Vice President and General Counsel, PG&E Corporation	November 13, 2006 to present
	Vice President, General Counsel and Secretary, Allegheny Energy, Inc. (an investor-owned utility company headquartered in Pennsylvania)	April 5, 2005 to October 17, 2006
	Senior Vice President, General Counsel and Secretary, Sithe Energies, Inc.	March 2000 to February 2005
Stewart M. Ramsay	Vice President, Asset Management and Electric Transmission	January 9, 2006 to present
	Vice President, Electric Transmission	July 1, 2005 to January 8, 2006
	Vice President, Distribution Asset Management, American Electric Power	February 1, 2004 to June 30, 2005
	Senior Vice President, Power and Gas, UMS Group, Inc.	October 1, 2001 to January 31, 2004
Fong Wan	Vice President, Energy Procurement	January 9, 2006 to present
	Vice President, Power Contracts and Electric Resource Development	May 1, 2004 to January 8, 2006
	Vice President, Risk Initiatives, PG&E Corporation Support Services, Inc.	November 1, 2000 to April 30, 2004

PART II

Item 5. ***Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***

As of February 1, 2007, there were 92,901 holders of record of PG&E Corporation common stock. PG&E Corporation common stock is listed on the New York Stock Exchange and the Swiss stock exchanges. The high and low sales prices of PG&E Corporation common stock for each quarter of the two most recent fiscal years are set forth under the heading "Quarterly Consolidated Financial Data (Unaudited)" in the 2006 Annual Report, which information is hereby incorporated by reference and filed as part of Exhibit 13 to this report. The discussion of dividends with respect to PG&E Corporation's common stock is hereby incorporated by reference from "Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Financial Resources - Dividends" of the 2006 Annual Report.

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 PG&E Corporation common stock at an exercise price of $0.01 per share. During the year ended December 31, 2006, warrant holders exercised, on a net exercise basis, warrants to purchase 51,904 shares, and received 51,890 shares of PG&E Corporation common stock in reliance on the exemption from the registration requirements of the Securities Act of 1933 provided by Section 4 (2) of the Act. As of December 31, 2006, warrant holders had exercised, on a net exercise basis, warrants to purchase 5,066,931 shares, and had received 5,065,099 shares of PG&E Corporation common stock since the warrants were issued. There are no more warrants outstanding.

Pacific Gas and Electric Company did not make any sales of unregistered equity securities during the quarter ended December 31, 2006.

Issuer Purchases of Equity Securities

PG&E Corporation common stock:

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs [1]	Approximate Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs (2)
October 1 through October 31, 2006	-	$ -	-	$ 500,000,000
November 1 through November 30, 2006	-	$ -	-	$ 500,000,000
December 1 through December 31, 2006	-	$ -	-	$ 500,000,000
Total	-	$ -	-	$ 500,000,000

(1) On October 19, 2005, the PG&E Corporation Board of Directors authorized the repurchase of up to $1.6 billion of shares of PG&E Corporation's common stock from time to time, but no later than December 31, 2006. No purchases were made under this authorization during the quarter ended December 31, 2006.
(2) The authority to repurchase shares under this authorization expired on December 31, 2006 .

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

Item 6. ***Selected Financial Data***

A summary of selected financial information, for each of PG&E Corporation and Pacific Gas and Electric Company for each of the last five fiscal years, is set forth under the heading “Selected Financial Data” in the 2006 Annual Report, which information is hereby incorporated by reference and filed as part of Exhibit 13 to this report.

Item 7. ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

A discussion of PG&E Corporation's and Pacific Gas and Electric Company's consolidated financial condition and results of operations is set forth under the heading “Management's Discussion and Analysis of Financial Condition and Results of Operations” in the 2006 Annual Report, which discussion is hereby incorporated by reference and filed as part of Exhibit 13 to this report.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

Information responding to Item 7A appears in the 2006 Annual Report under the heading “Management's Discussion and Analysis of Financial Condition and Results of Operations - Risk Management Activities,” and under Notes 2 and 12 of the “Notes to the Consolidated Financial Statements” of the 2006 Annual Report, which information is hereby incorporated by reference and filed as part of Exhibit 13 to this report.

Item 8. ***Financial Statements and Supplementary Data***

Information responding to Item 8 appears in the 2006 Annual Report under the following headings for PG&E Corporation: “Consolidated Statements of Income,” “Consolidated Balance Sheets,” “Consolidated Statements of Cash Flows,” and “Consolidated

Statements of Shareholders' Equity;" under the following headings for Pacific Gas and Electric Company: "Consolidated Statements of Income," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Shareholders' Equity;" and under the following headings for PG&E Corporation and Pacific Gas and Electric Company jointly: "Notes to the Consolidated Financial Statements," "Quarterly Consolidated Financial Data (Unaudited)," and "Report of Independent Registered Public Accounting Firm," which information is hereby incorporated by reference and filed as part of Exhibit 13 to this report.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

Not applicable.

Item 9A. ***Controls and Procedures***

Based on an evaluation of PG&E Corporation's and the Utility's disclosure controls and procedures as of December 31, 2006, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures are effective to ensure that information required to be disclosed by PG&E Corporation and the Utility in reports that the companies file or submit under the Securities Exchange Act of 1934, or the 1934 Act, is recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms. In addition, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures were effective in ensuring that information required to be disclosed by PG&E Corporation and the Utility in the reports that PG&E Corporation and the Utility file or submit under the 1934 Act is accumulated and communicated to PG&E Corporation's and the Utility's management, including PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

There were no changes in internal control over financial reporting that occurred during the quarter ended December 31, 2006 that have materially affected, or are reasonably likely to materially affect, PG&E Corporation's or the Utility's internal control over financial reporting.

Management of PG&E Corporation and the Utility have prepared an annual report on internal control over financial reporting. Management's report, together with the report of the independent registered public accounting firm, appears in the 2006 Annual Report under the heading "Management's Report on Internal Control Over Financial Reporting" and "Report of Independent Registered Public Accounting Firm," which information is hereby incorporated by reference and filed as part of Exhibit 13 to this report.

Item 9B. ***Other Information***

Officer Appointments

On February 21, 2007, the Utility's Board of Directors elected William T. Morrow, 47, as President and Chief Executive Officer of the Utility, effective July 1, 2007. Mr. Morrow will continue to report to Thomas B. King, currently Chief Executive Officer of the Utility, who will become President of PG&E Corporation effective July 1, 2007. Peter A. Darbee, currently Chairman of the Board, Chief Executive Officer, and President of PG&E Corporation, will become Chairman of the Board and Chief Executive Officer of PG&E Corporation effective July 1, 2007. Mr. Darbee will continue to serve as Chairman of the Board of the Utility.

Mr. Morrow has been President and Chief Operating Officer of the Utility since August 15, 2006. Before joining the Utility, Mr. Morrow held various executive positions in the telecommunications industry. Most recently Mr. Morrow served as Chief Executive Officer, Europe, of Vodafone Group PLC, a position he held from May 2006 to July 2006. From April 2005 to April 2006, Mr. Morrow served as President of Vodafone K.K. in Japan and from February 2004 to March 2005, he was Chief Executive Officer of Vodafone, U.K., Ltd. From December 2001 through January 2004, Mr. Morrow was President of Japan Telecom Holdings Co., Inc. and Japan Telecom Co., Inc. Previously in 2001, Mr. Morrow was Vice President and Country Manager, Japan for Vodafone Group PLC.

Mr. King has served as Chief Executive Officer of the Utility since August 15, 2006. Prior to that date, Mr. King served as President and Chief Executive Officer of the Utility, a position he held from January 1, 2006 to August 14, 2006. He served as Executive Vice President and Chief Operating Officer of the Utility from July 1, 2005 to December 31, 2005, and as Executive Vice President and Chief of Utility Operations from August 2, 2004 to June 30, 2005. From November 1, 2003 to August 1, 2004, he was Senior Vice President and Chief of Utility Operations of the Utility. Prior to November 1, 2003, Mr. King had been a Senior Vice President of PG&E Corporation from January 1, 1999. Since 2000, Mr. King also held various executive positions at PG&E National

Energy Group, Inc., a former subsidiary of PG&E Corporation involved in power generation, natural gas transmission, and wholesale energy marketing and trading. Mr. King focused his activities primarily in the natural gas transmission business. From November 15, 2002 to July 8, 2003, Mr. King served as the President and as a director of PG&E National Energy Group, Inc.

Mr. King and Mr. Morrow are entitled to receive equity awards under the PG&E Corporation 2006 Long-Term Incentive Plan and the PG&E Corporation Executive Stock Ownership Program. They are also eligible to receive annual cash incentive awards under an annual Short-Term Incentive Plan adopted by the PG&E Corporation Board of Directors. The Utility p rovides retirement benefits to all of its employees, including its officers, under a tax-qualified defined benefit pension plan. Officers of PG&E Corporation and the Utility are also entitled to receive pension benefits under the PG&E Corporation Supplemental Executive Retirement Plan, a non-tax qualified defined benefit pension plan. Officers of PG&E Corporation and the Utility may also participate in the PG&E Corporation Retirement Savings Plan, a 401(k) plan available to all eligible employees, and the PG&E Corporation Supplemental Retirement Savings Plan. PG&E Corporation also has adopted an Officer Severance Policy that covers officers of PG&E Corporation and the Utility. These plans, as well as perquisites provided to officers, are described in PG&E Corporation's and the Utility's 2006 joint proxy statement filed with the Securities and Exchange Commission.

Neither Mr. Morrow nor Mr. King has any relationship or related transaction with PG&E Corporation or the Utility that would require disclosure pursuant to Item 404(a) of Securities and Exchange Commission Regulation S-K.

2007 Short-Term Incentive Plan

As previously disclosed, the Nominating, Compensation and Governance Committee of the PG&E Corporation Board of Directors, or the Committee, has approved the structure of the PG&E Corporation 2007 Short-Term Incentive Plan, or STIP, under which officers of PG&E Corporation and the Utility are provided an opportunity to receive annual incentive cash payments. Corporate financial performance, as measured by corporate earnings from operations, will account for 50 percent of the incentive , 20 percent of the incentive will be based on customer satisfaction indices, 20 percent of the incentive will be based on the Utility's success in implementing its strategy to achieve operational excellence and improved customer service, 5 percent will be based on the results of an employee opinion survey measuring employee engagement, and the remaining 5 percent will be based on achieving safety standards. At its meeting on February 21, 2007, the Committee approved the specific performance scale that will be used to determine the extent to which the corporate financial objective, as measured by earnings from operations, has been met. The Committee used the same methodology to establish the performance scale for the corporate financial performance portion of the 2007 STIP as was used for the 2006 STIP. The corporate financial performance measure is based on PG&E Corporation's budgeted earnings from operations that were previously approved by the Board, consistent with the basis for reporting and guidance to the financial community. As with previous earnings performance scales, unbudgeted items impacting comparability such as changes in accounting methods, workforce restructuring, and one-time occurrences will be excluded.

The Committee also approved the 2007 performance targets for each of the four other measures set forth in the table below. The 2006 performance results for each measure are included for comparative purposes.

2007 STIP Performance Targets (1)

Measure	Relative Weight	2006 Results	2007 Target
Customer Satisfaction (Residential & Business) (2)	20%	100	676
Business Transformation Index (3)	20%	N/A	1.0
Employee Survey (Premier) Index (4)	5%	64.0%	66.0%
Occupational Safety and Health Administration (OSHA) Recordable Injury Rate (5)	5%	12.9% reduction	15% reduction

1. As explained above, 50% of the STIP award will be based on achievement of corporate earnings from operations targets.

2. This measure reflects a weighted composite of the overall customer satisfaction indices of the Utility's residential and business customers as reported by the J.D. Power Residential Survey and the J.D. Power Business Survey. For 2006, the residential customers' and business customers' scores were weighted equally. In an effort to enhance the focus on improving residential customer satisfaction, which has been lower than business customer satisfaction, for the 2007 target the weighting of the residential customers' score will be increased to 60% and the weighting of the business customers' score will be lowered to 40%. In addition, for 2007, J.D. Power and Associates has changed the scale used to report results from the J.D. Power Survey from a scale that attempted to center the industry average score at approximately 100 to a 1,000-point scale. By way of comparison, results for 2006 would have been 678 under the new 1000-point scale based on equally weighted scores and results for 2006 would have been 673 based on the revised weightings. The 2007 target may be adjusted to reflect changes in the J.D. Power industry average scores, which are expected by mid-year 2007.

3. The Business Transformation Index is comprised of five measurement points that define success in achieving key Business Transformation operational, financial, and post-implementation objectives. The five measurement points are (1) overall Business Transformation cost performance in comparison to budgeted amounts, (2) overall business transformation benefit performance in comparison to planned/budgeted amounts, (3) new business customer connection performance for cycle time and number of customer commitments met, (4) SmartMeter ^{TM} project performance for number of meters installed and activated, and (5) the extent to which core business transformation initiatives are implemented compared to planned schedule and scope of initiatives.

4. The Premier Survey is the primary tool used to measure employee engagement at PG&E Corporation and the Utility. The employee index is designed around 15 key drivers of employee engagement. The average overall employee survey index score provides a comprehensive metric that is derived by adding the percent of favorable responses from all 40 core survey items (all of which fall into one of 15 broader topical areas), and then dividing the total sum by 40.

5. An “OSHA Recordable” is an occupational (job-related) injury or illness that requires medical treatment beyond first aid, or results in work restrictions, death or loss of consciousness. The “OSHA Recordable Rate” is the number of OSHA Recordables for every 200,000 hours worked, or for approximately 100 employees. This metric measures the percentage reduction in the Utility’s OSHA Recordable rate from the prior year.

The Committee has full discretion as to the determination of final officer STIP awards for 2007 performance.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

Information regarding executive officers of PG&E Corporation and Pacific Gas and Electric Company is included above in a separate item captioned “Executive Officers of the Registrants” at the end of Part I of this report. Other information responding to Item 10 is included under the heading “Item No. 1: Election of Directors of PG&E Corporation and Pacific Gas and Electric Company” and under the heading “Section 16(a) Beneficial Ownership Reporting Compliance” in the Joint Proxy Statement relating to the 2007 Annual Meetings of Shareholders, which information is hereby incorporated by reference.

Website Availability of Code of Ethics, Corporate Governance and Other Documents

The following documents are available both on PG&E Corporation's website *www.pgecorp.com* , and Pacific Gas and Electric Company's website, *www.pge.com* : (1) the codes of conduct and ethics adopted by PG&E Corporation and Pacific Gas and Electric Company applicable to their respective directors and employees, including their respective Chief Executive Officers, Chief Financial Officers, Controllers and other executive officers, (2) PG&E Corporation's and Pacific Gas and Electric Company's corporate governance guidelines, and (3) key Board Committee charters, including charters for the companies' Audit Committees and the PG&E Corporation Nominating, Compensation, and Governance Committee. Shareholders also may obtain print copies of these documents by submitting a written request to Linda Y.H. Cheng, Vice President, Corporate Governance and Corporate Secretary of PG&E Corporation and Pacific Gas and Electric Company, One Market, Spear Tower, Suite 2400, San Francisco, California 94105.

If any amendments are made to, or any waivers are granted with respect to, provisions of the codes of conduct and ethics adopted by PG&E Corporation and Pacific Gas and Electric Company that apply to their respective Chief Executive Officers, Chief Financial Officers or Controllers, the company whose code is so affected will disclose the nature of such amendment or waiver on its respective website and any waivers to the code will be disclosed in a Current Report on Form 8-K filed within 4 business days of the waiver.

Procedures for Shareholder Recommendations of Nominees to the Boards of Directors

During 2006 there were no material changes to the procedures described in PG&E Corporation’s and the Utility’s joint proxy statement relating to the 2006 Annual Meetings of Shareholders by which security holders may recommend nominees to PG&E Corporation’s or the Utility’s Boards of Directors.

Audit Committees and Audit Committee Financial Expert

Information regarding the Audit Committees of PG&E Corporation and the Utility and the “audit committee financial expert” as defined by the SEC is included under the heading “ Information Regarding the Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company - Board Committees- Audit Committees” in the Joint Proxy Statement relating to the 2007 Annual Meetings of Shareholders, which information is hereby incorporated by reference.

Item 11. ***Executive Compensation***

Information responding to Item 11, for each of PG&E Corporation and Pacific Gas and Electric Company, is included under

the headings “Compensation Discussion and Analysis,” “Compensation Committee Report,” “Summary Compensation Table,” “Grants of Plan-based Awards in 2006,” “Outstanding Equity Awards at Fiscal Year End,” “Option Exercises and Stock Vested During 2006,” “Pension Benefits,” “Nonqualified Deferred Compensation,” and “Compensation of Directors,” and “Potential Payments Upon Resignation, Retirement, Termination, Change in Control, Death, or Disability” in the Joint Proxy Statement relating to the 2007 Annual Meetings of Shareholders, which information is hereby incorporated by reference.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters***

Information responding to Item 12, for each of PG&E Corporation and Pacific Gas and Electric Company, is included under the heading “Security Ownership of Management” and under the heading “Principal Shareholders” in the Joint Proxy Statement relating to the 2007 Annual Meetings of Shareholders, which information is hereby incorporated by reference.

Equity Compensation Plan Information

The following table provides information as of December 31, 2006 concerning shares of PG&E Corporation common stock authorized for issuance under PG&E Corporation's existing equity compensation plans.

Plan Category	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	(b) Weighted Average Exercise Price of Outstanding Options, Warrants and Rights	(c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column(a))
Equity compensation plans approved by shareholders	6,477,959 (1)	$ 24.16	11,421,085 (2)
Equity compensation plans not approved by shareholders	—	$ —	—
Total equity compensation plans	6,477,959 (1)	$ 24.16	11,421,085 (2)

(1) Includes 79,639 phantom stock units and restricted stock units. The weighted average exercise price reported in column (b) does not take these awards into account.

(2) Represents the total number of shares available for issuance under PG&E Corporation's Long-Term Incentive Program, or LTIP, and the PG&E Corporation 2006 Long-Term Incentive Plan, or 2006 LTIP, as of December 31, 2006. Outstanding stock-based awards granted under the LTIP include stock options, restricted stock and phantom stock payable in an equal number of shares upon termination of employment or service as a director. The LTIP expired on December 31, 2005. The 2006 LTIP, which became effective on January 1, 2006 authorizes up to 12 million shares to be issued pursuant to awards granted under the 2006 LTIP. Outstanding stock-based awards granted under the 2006 LTIP include stock options, restricted stock, restricted stock units and phantom stock payable in an equal number of shares upon termination of employment or service as a director. For a description of the LTIP and the 2006 LTIP, see Note 14 of the Notes to the Consolidated Financial Statements in the 2006 Annual Report.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

Information responding to Item 13, for each of PG&E Corporation and Pacific Gas and Electric Company, is included under the headings “Related Person Transactions,” “Review, Approval, and Ratification of Related Person Transactions” and “ Information Regarding the Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company - Director Independence” in the Joint Proxy Statement relating to the 2007 Annual Meetings of Shareholders, which information is hereby incorporated by reference.

Item 14. ***Principal Accountant Fees and Services***

Information responding to Item 14, for each of PG&E Corporation and Pacific Gas and Electric Company, is included under the heading “Information Regarding the Independent Registered Public Accounting Firm of PG&E Corporation and Pacific Gas and Electric Company” in the Joint Proxy Statement relating to the 2007 Annual Meetings of Shareholders, which information is hereby incorporated by reference.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

(a) The following documents are filed as a part of this report:

1. The following consolidated financial statements, supplemental information and report of independent registered public accounting firm are contained in the 2006 Annual Report and are incorporated by reference in this report:

Consolidated Statements of Income for the Years Ended December 31, 2006, 2005, and 2004, for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Balance Sheets at December 31, 2006, and 2005 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 2006, 2005, and 2004, for each of PG&E Corporation and Pacific Gas and Electric Company.

Notes to the Consolidated Financial Statements.

Quarterly Consolidated Financial Data (Unaudited).

Report of Independent Registered Public Accounting Firm (Deloitte & Touche LLP).

2. The following financial statement schedules and report of independent registered public accounting firm are filed as part of this report:

Report of Independent Registered Public Accounting Firm (Deloitte & Touche LLP).

I - Condensed Financial Information of Parent as of December 31, 2006 and 2005 and for the Years Ended December 31, 2006, 2005, and 2004.

II - Consolidated Valuation and Qualifying Accounts for each of PG&E Corporation and Pacific Gas and Electric Company for the Years Ended December 31, 2006, 2005, and 2004.

Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto.

3. Exhibits required by Item 601 of Regulation S-K:

Exhibit Number	Exhibit Description
2.1	Order of the U.S. Bankruptcy Court for the Northern District of California dated December 22, 2003, Confirming Plan of Reorganization of Pacific Gas and Electric Company, including Plan of Reorganization, dated July 31, 2003 as modified by modifications dated November 6, 2003 and December 19, 2003 (Exhibit B to Confirmation Order and Exhibits B and C to the Plan of Reorganization omitted) (incorporated by reference to Pacific Gas and Electric Company's Registration Statement on Form S-3 No. 333-109994, Exhibit 2.1)
2.2	Order of the U.S. Bankruptcy Court for the Northern District of California dated February 27, 2004 Approving Technical Corrections to Plan of Reorganization of Pacific Gas and Electric Company and Supplementing Confirmation Order to Incorporate such Corrections (incorporated by reference to Pacific Gas and Electric Company's Registration Statement on Form S-3 No. 333-109994, Exhibit 2.2)
3.1	Restated Articles of Incorporation of PG&E Corporation effective as of May 29, 2002 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609), Exhibit 3.1)
3.2	Certificate of Determination for PG&E Corporation Series A Preferred Stock filed December 22, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 3.2)
3.3	Bylaws of PG&E Corporation amended as of December 20, 2006
3.4	Restated Articles of Incorporation of Pacific Gas and Electric Company effective as of April 12, 2004 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K filed April 12, 2004 (File No. 1-2348), Exhibit 3)
3.5	Bylaws of Pacific Gas and Electric Company amended as of December 20, 2006
4.1	Indenture, dated as of April 22, 2005, supplementing, amending and restating the Indenture of Mortgage, dated as of March 11, 2004, as supplemented by a First Supplemental Indenture, dated as of March 23, 2004, and a Second Supplemental Indenture, dated as of April 12, 2004, between Pacific Gas and Electric Company and The Bank of New York Trust Company, N.A. (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q filed May 4, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 4.1)
4.2	Indenture related to PG&E Corporation's 7.5% Convertible Subordinated Notes due June 2007, dated as of June 25, 2002, between PG&E Corporation and U.S. Bank, N.A., as Trustee (incorporated by reference to PG&E Corporation's Form 8-K filed June 26, 2002 (File No. 1-12609), Exhibit 99.1).
4.3	Supplemental Indenture related to PG&E Corporation's 9.50% Convertible Subordinated Notes due June 2010, dated as of October 18, 2002, between PG&E Corporation and U.S. Bank, N.A., as Trustee (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2002 (File No. 1-12609), Exhibit 4.1)
4.4	Warrant Agreement, dated as of October 18, 2002, by and among PG&E Corporation, LB I Group Inc., and each other entity named on the signature pages thereto (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2002 (File No. 1-12609), Exhibit 4.2)
10.1	Credit Agreement dated as of April 8, 2005, among Pacific Gas and Electric Company, Citicorp North America, Inc., as administrative agent and a lender, JP Morgan Chase Bank, N.A., as syndication agent and a lender, Barclays Bank PLC, BNP Paribas and Deutsche Bank Securities Inc., as documentation agents and lenders, ABN Amro Bank N.V., Lehman Brothers Bank, FSB, Mellon Bank, N.A., Royal Bank of Canada, The Bank of New York, The Bank of Nova Scotia, UBS Loan Finance LLC, and Union Bank of California, N.A., as senior managing agents, and KBC Bank, NV, Morgan Stanley Bank and William Street Commitment Corporation, as lenders (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q filed May 4, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 10.3)
10.2	First Amendment, dated as of November 30, 2005, to the Credit Agreement among Pacific Gas and Electric Company, Citicorp North America, Inc., as administrative agent and a lender, JPMorgan Chase Bank, N.A., as syndication agent and a lender, Barclays Bank PLC and BNP Paribas as documentation agents and lenders, Deutsche Bank Securities Inc., as documentation agent, and the following other lenders: Deutsche Bank AG New York Branch, ABN Amro Bank N.V., Lehman Brothers Bank, FSB, Mellon Bank, N.A., Royal Bank of Canada, The Bank of New York, UBS Loan Finance LLC, Union Bank of California, N.A., KBC Bank, N.V., Morgan Stanley Bank and William Street Commitment Corporation. (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 10.2)
10.3	Credit Agreement, dated as of December 10, 2004, among PG&E Corporation, BNP Paribas, as administrative agent and a lender, Deutsche Bank Securities, as syndication agent, ABN Amro Bank, N.V., Goldman Sachs Credit Partners L.P., and Union Bank of California, N.A., as documentation agents and lenders, and the following other lenders: Barclays Bank PLC, Citicorp USA, Inc., Deutsche Bank AG New York Branch, JP Morgan Chase Bank, N.A., Lehman Brothers Bank, FSB, Morgan Stanley Bank, Royal Bank of Canada, The Bank of Nova Scotia, and The Bank of New York (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed December 15, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 99)
10.4	First Amendment, dated as of April 8, 2005, to the Credit Agreement dated as of December 10, 2004, among PG&E Corporation, BNP Paribas, as administrative agent and a lender, Deutsche Bank Securities Inc., as syndication agent and a lender, ABN Amro Bank,

N.V., Goldman Sachs Credit Partners L.P., and Union Bank of California, N.A., as documentation agents and lenders, and the following other lenders: Barclays Bank PLC, Citicorp USA, Inc., Deutsche Bank AG New York Branch, JP Morgan Chase Bank, N.A., Lehman Brothers Bank, FSB, Morgan Stanley Bank, Royal Bank of Canada, The Bank of Nova Scotia, KBC Bank N.V., and The Bank of New York (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q filed May 4, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 10.2)

10.5 Master Confirmation dated November 16, 2005, for accelerated share repurchase arrangements between PG&E Corporation and Goldman, Sachs & Co. (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 10.5)

10.6 Settlement Agreement among California Public Utilities Commission, Pacific Gas and Electric Company and PG&E Corporation, dated as of December 19, 2003, together with appendices (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 8-K filed December 22, 2003) (File No. 1-12609 and File No. 1-2348), Exhibit 99)

10.7 Firm Transportation Service Agreement between Pacific Gas and Electric Company and Pacific Gas Transmission Company dated October 26, 1993, Rate Schedule FTS-1, and general terms and conditions (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2003) (File No. 1-12609 and File No. 1-2348), Exhibit 10.4)

10.8 Operating Agreement between Pacific Gas and Electric Company and Pacific Gas Transmission Company dated July 9, 1996 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2003) (File No. 1-12609 and File No. 1-2348), Exhibit 10.5)

10.9 Transmission Control Agreement among the California Independent System Operator (CAISO) and the Participating Transmission Owners, including Pacific Gas and Electric Company, effective as of March 31, 1998, as amended (CAISO, FERC Electric Tariff No. 7) (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.8)

10.10 Operating Agreement, as amended on November 12, 2004, effective as of December 22, 2004, between the State of California Department of Water Resources and Pacific Gas and Electric Company (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.9)

*10.11 PG&E Corporation Supplemental Retirement Savings Plan amended effective as of September 19, 2001, and frozen after December 31, 2004 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004) (File No. 1-12609), Exhibit 10.10)

*10.12 PG&E Corporation Supplemental Retirement Savings Plan effective as of January 1, 2005 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004) (File No. 1-12609), Exhibit 10.11)

*10.13 Letter regarding Compensation Arrangement between PG&E Corporation and Peter Darbee effective July 1, 2003 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609), Exhibit 10.4)

* 10.14 Letter regarding Compensation Arrangement between PG&E Corporation and Thomas B. King dated June 18, 2003 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609), Exhibit 10.3)

*10.15 Retention Agreement between PG&E Corporation and Thomas B. King dated August 31, 2006 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2006 (File No. 1-12609), Exhibit 10.2)

*10.16 Letter regarding Compensation Arrangement between Pacific Gas and Electric Company and William T. Morrow dated June 20, 2006 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2006 (File No. 1-12609), Exhibit 10.1 **)**

*10.17 Letter regarding Compensation Arrangement between PG&E Corporation and Rand L. Rosenberg dated October 19, 2005 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005) (File No. 1-12609), Exhibit 10.18)

*10.18 Letter regarding Compensation Arrangement between PG&E Corporation and Hyun Park dated October 10, 2006

*10.19 PG&E Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, effective as of January 1, 2005 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004) (File No. 1-12609), Exhibit 10.17)

*10.20 Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2007

*10.21 Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.23)

*10.22 Supplemental Executive Retirement Plan of the Pacific Gas and Electric Company amended effective as of December 31, 2004, and frozen as of January 1, 2005 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004) (File No. 1-2348), Exhibit 10.20)

*10.23 Supplemental Executive Retirement Plan of PG&E Corporation as amended effective as of January 1, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005) (File No. 1-2348), Exhibit 10.27)

*10.24 Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Bruce R. Worthington dated December 20, 2002 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.37.2)

*10.25 Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Bruce R. Worthington dated April 18, 2003 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609), Exhibit 10.2.5)

*10.26 Pacific Gas and Electric Company Relocation Assistance Program for Officers (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for fiscal year 1989 (File No. 1-2348), Exhibit 10.16)

*10.27 Postretirement Life Insurance Plan of the Pacific Gas and Electric Company (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for fiscal year 1991 (File No. 1-2348), Exhibit 10.16)

*10.28 PG&E Corporation Non-Employee Director Stock Incentive Plan (a component of the PG&E Corporation Long-Term Incentive Program) as amended effective as of July 1, 2004 (reflecting amendments adopted by the PG&E Corporation Board of Directors on June 16, 2004 set forth in resolutions filed as Exhibit 10.3 to PG&E Corporation's and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004 **)** (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.27)

*10.29 Resolution of the PG&E Corporation Board of Directors dated June 16, 2004, adopting director compensation arrangement (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12609 and File No. 12348), Exhibit 10.1)

*10.30 Resolution of the Pacific Gas and Electric Company Board of Directors dated June 16, 2004, adopting director compensation arrangement (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12609 and File No. 12348), Exhibit 10.2)

*10.31 Resolution of the PG&E Corporation Board of Directors dated December 20, 2006, adopting director compensation arrangement effective January 1, 2007

*10.32 Resolution of the Pacific Gas and Electric Company Board of Directors dated December 20, 2006, adopting director compensation arrangement effective January 1, 2007

*10.33 PG&E Corporation 2006 Long-Term Incentive Plan, as amended on February 15, 2006 (with respect to change in control provisions) and December 20, 2006 (with respect to Section 7 governing nondiscretionary awards to non-employee directors)

*10.34 PG&E Corporation Long-Term Incentive Program (including the PG&E Corporation Stock Option Plan and Performance Unit Plan), as amended May 16, 2001, (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2001 (File No. 1-12609), Exhibit 10)

*10.35 Form of Restricted Stock Award Agreement for 2003 grants made under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.46)

*10.36 Form of Restricted Stock Award Agreement for 2004 grants made under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2003 (File No. 1-12609), Exhibit 10.37)

*10.37 Form of Restricted Stock Agreement for 2005 grants under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 6, 2005 (File No. 12609 and File No. 1-2348), Exhibit 99.3)

*10.38 Form of Restricted Stock Agreement for 2006 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 9, 2006, Exhibit 99.1)

*10.39 Form of Restricted Stock Agreement for 2007 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (reflecting amendments to the PG&E Corporation 2006 Long-Term Incentive Plan made on February 15, 2006)

*10.40 Form of Non-Qualified Stock Option Agreement under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 6, 2005 (File No. 12609 and File No. 1-2348), Exhibit 99.1)

*10.41 Form of Performance Share Award Agreement for 2004 grants under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2003 (File No. 1-12609), Exhibit 10.38)

*10.42 Form of Performance Share Agreement for 2005 grants under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 6, 2005 (File No. 12609 and File No. 1-2348), Exhibit 99.2)

*10.43 Form of Performance Share Agreement for 2006 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 9, 2006, Exhibit 99.2)

*10.44 Form of Performance Share Agreement for 2007 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (reflecting amendments to the PG&E Corporation 2006 Long-Term Incentive Plan made on February 15, 2006)

*10.45 PG&E Corporation Executive Stock Ownership Program Guidelines dated as of February 19, 2003 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609) Exhibit 10.2)

*10.46 PG&E Corporation Executive Stock Ownership Program Guidelines as amended February 15, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005 (File No. 1-12609), Exhibit 10.46)

*10.47 PG&E Corporation Officer Severance Policy, as amended effective as of January 1, 2005 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.37)

*10.48	PG&E Corporation Officer Severance Policy, as amended effective as of February 15, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005 (File No. 1-12609), Exhibit 10.48)
*10.49	PG&E Corporation Golden Parachute Restriction Policy effective as of February 15, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005 (File No. 1-12609), Exhibit 10.49)
*10.50	PG&E Corporation Director Grantor Trust Agreement dated April 1, 1998 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 1998 (File No. 1-12609), Exhibit 10.1)
*10.51	PG&E Corporation Officer Grantor Trust Agreement dated April 1, 1998, as updated effective January 1, 2005 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.39)
*10.52	Resolution of the Board of Directors of PG&E Corporation regarding indemnification of officers and directors dated December 18, 1996 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.40)
*10.53	Resolution of the Board of Directors of Pacific Gas and Electric Company regarding indemnification of officers and directors dated July 19, 1995 (incorporated by reference to Pacific Gas and Electric Company’s Form 10-K for the year ended December 31, 2004 (File No. 1-2348), Exhibit 10.41)
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
13	The following portions of the 2006 Annual Report to Shareholders of PG&E Corporation and Pacific Gas and Electric Company are included: “Selected Financial Data,” “Management's Discussion and Analysis of Financial Condition and Results of Operations,” financial statements of PG&E Corporation entitled “Consolidated Statements of Income,” “Consolidated Balance Sheets,” “Consolidated Statements of Cash Flows,” and “Consolidated Statements of Shareholders' Equity,” financial statements of Pacific Gas and Electric Company entitled “Consolidated Statements of Income,” “Consolidated Balance Sheets,” “Consolidated Statements of Cash Flows,” and “Consolidated Statements of Shareholders' Equity,” “Notes to the Consolidated Financial Statements,” and “Quarterly Consolidated Financial Data (Unaudited),” “Management's Report on Internal Control Over Financial Reporting,” “Report of Independent Registered Public Accounting Firm,” and “Report of Independent Registered Public Accounting Firm.”
21	Subsidiaries of the Registrant
23	Consent of Independent Registered Public Accounting Firm (Deloitte & Touche LLP)
24.1	Resolutions of the Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company authorizing the execution of the Form 10-K
24.2	Powers of Attorney
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 Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrants have duly caused this Annual Report on Form 10-K for the year ended December 31, 2006 to be signed on their behalf by the undersigned, thereunto duly authorized.

PG&E CORPORATION (Registrant)		PACIFIC GAS AND ELECTRIC COMPANY (Registrant)	
By:	HYUN PARK (Hyun Park, Attorney-in-Fact)	By:	HYUN PARK (Hyun Park, Attorney-in-Fact)
Date:	February 22, 2007	Date:	February 22, 2007

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrants and in the capacities and on the dates indicated.

Signature	Title	Date
A. Principal Executive Officers		
*PETER A. DARBEE	Chairman of the Board, Chief Executive Officer and President (PG&E Corporation)	February 22, 2007
*THOMAS B. KING	Chief Executive Officer (Pacific Gas and Electric Company)	February 22, 2007
B. Principal Financial Officer		
*CHRISTOPHER P. JOHNS	Senior Vice President, Chief Financial Officer and Treasurer (PG&E Corporation and Pacific Gas and Electric Company)	February 22, 2007
C. Principal Accounting Officer		
*G. ROBERT POWELL	Vice President and Controller (PG&E Corporation and Pacific Gas and Electric Company)	February 22, 2007
D. Directors		
*DAVID R. ANDREWS *LESLIE S. BILLER *DAVID A. COULTER *C. LEE COX *PETER A. DARBEE *MARYELLEN C. HERRINGER *THOMAS B. KING (Director of Pacific Gas and Electric Company only) *RICHARD A. MESERVE *MARY S. METZ *BARBARA L. RAMBO *BARRY LAWSON WILLIAMS	Directors of PG&E Corporation and Pacific Gas and Electric Company, except as noted	February 22, 2007

*By HYUN PARK
(Hyun Park, Attorney-in-Fact)

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Boards of Directors and Shareholders of
PG&E Corporation and Pacific Gas and Electric Company

We have audited the consolidated financial statements of PG&E Corporation and subsidiaries (the "Company") and Pacific Gas and Electric Company and subsidiaries (the "Utility") as of December 31, 2006 and 2005, and for each of the three years in the period ended December 31, 2006, management's assessment of the effectiveness of the Company's and the Utility's internal control over financial reporting as of December 31, 2006, and the effectiveness of the Company's and the Utility's internal control over financial reporting as of December 31, 2006, and have issued our reports thereon dated February 21, 2007; such consolidated financial statements and reports are included in your 2006 Annual Report to Shareholders of the Company and the Utility and are incorporated herein by reference. Our audits also included the consolidated financial statement schedules of the Company and the Utility listed in Item 15 (a) 2. These consolidated financial statement schedules are the responsibility of the Company's and the Utility's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

DELOITTE & TOUCHE LLP

San Francisco, California

February 21, 2007

PG&E CORPORATION
SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF PARENT
CONDENSED BALANCE SHEETS
(in millions)

	Balance at December 31,	
	2006	**2005**
ASSETS		
Cash and cash equivalents	$ 386	$ 250
Advances to affiliates	42	38
Other current assets	3	3
Total current assets	431	291
Equipment	15	15
Accumulated depreciation	(14)	(14)
Net equipment	1	1
Investments in subsidiaries	7,959	7,401
Other investments	81	71
Deferred income taxes	132	127
Other	10	15
Total Assets	$ 8,614	$ 7,906
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable—related parties	$ 41	$ 27
Accounts payable—other	18	17
Long-term debt, classified as current	280	-
Income taxes payable	122	28
Other	210	193
Total current liabilities	671	265
Noncurrent Liabilities:		
Long-term debt	-	280
Other	133	143
Total noncurrent liabilities	133	423
Preferred stock	—	—
Common Shareholders' Equity		
Common stock	5,877	5,827
Common stock held by subsidiary	(718)	(718)
Unearned compensation	-	(22)
Reinvested earnings	2,670	2,139
Accumulated other comprehensive loss	(19)	(8)
Total common shareholders' equity	7,810	7,218
Total Liabilities and Shareholders' Equity	$ 8,614	$ 7,906

PG&E CORPORATION
SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF PARENT — (Continued)
CONDENSED STATEMENTS OF INCOME
(in millions, except per share amounts)

	Year Ended December 31,		
	2006	**2005**	**2004**
Administrative service revenue	$ 110	$ 97	$ 85
Equity in earnings of subsidiaries	964	918	3,959
Operating expenses	(115)	(97)	(110)
Interest income	15	9	15
Interest expense	(30)	(35)	(132)
Other expense	(1)	(17)	(91)
Income before income taxes	943	875	3,726
Income tax benefit	48	29	94
Income from continuing operations	991	904	3,820
Gain on disposal of NEGT	—	13	684
Net income before intercompany eliminations	$ 991	$ 917	$ 4,504
Weighted average common shares outstanding	346	372	398
Earnings per common share, basic [1]	$ 2.78	$ 2.40	$ 10.80
Earnings per common share, diluted [1]	$ 2.76	$ 2.37	$ 10.57

CONDENSED STATEMENTS OF CASH FLOWS
(in millions)

	Year Ended December 31,		
	2006	**2005**	**2004**
Cash Flows from Operating Activities:			
Net income	$ 991	$ 917	$ 4,504
Gain on disposal of NEGT (net of income tax benefit of $13 million in 2005 and income tax expense of $374 million in 2004)	—	(13)	(684)
Net income from continuing operations	991	904	3,820
Adjustments to reconcile net income to net cash provided by operating activities:			
Equity in earnings of subsidiaries	(964)	(918)	(3,959)
Deferred taxes	2	(23)	27
NEGT settlement payment	—	—	(30)
Other	130	86	160
Net cash provided by operating activities	159	49	18
Cash Flows From Investing Activities:			
Capital expenditures	(1)	(1)	—
Investment in subsidiaries	—	—	(28)
Stock repurchase by subsidiary	—	1,910	—
Dividends received from subsidiaries	460	445	—
Restricted cash	—	—	361
Other	—	(38)	—
Net cash provided by investing activities	459	2,316	333
Cash Flows From Financing Activities [2] :			
Common stock issued	131	243	162
Common stock repurchased	(114)	(2,188)	(350)
Common stock dividends paid	(456)	(334)	—

Long-term debt redeemed	—	(2)	(652)
Other	(43)	(17)	(1)
Net cash used by financing activities	(482)	(2,298)	(841)
Net change in cash and cash equivalents	136	67	(490)
Cash and cash equivalents at January 1	250	183	673
Cash and cash equivalents at December 31	386	250	183

(1) PG&E Corporation adopted the consensus reached by Emerging Issues Task Force, or EITF, in EITF issue No. 03-06, "Participating Securities and the Two-Class Method under FASB Statement No. 128," or EITF 03-06, as ratified by the Financial Accounting Standards Board on March 31, 2004.

PG&E Corporation currently has outstanding $280 million principal amount of convertible subordinated 9.50% notes due 2010, or Convertible Notes, that are entitled to receive (non-cumulative) dividend payments without exercising the conversion option. These Convertible Notes, which were issued in June 2002, meet the criteria of a participating security in the calculation of earnings per share using the "two-class" method.

Accordingly, the basic and diluted earnings per share calculations for each of the years in the three year period ended December 31, 2006 reflect the allocation of earnings between PG&E Corporation common stock and the participating security.

(2) On January 16, April 15, July 15, and October 15, 2006, PG&E Corporation paid a quarterly common stock dividend of $0.33 per share, totaling approximately $489 million. Of the total dividend payments made by PG&E Corporation in 2006, approximately $33 million was paid to Elm Power Corporation, a wholly owned subsidiary of PG&E Corporation.

On April 15, July 15 and October 17, 2005, PG&E Corporation paid a quarterly common stock dividend of $0.30 per share, totaling approximately $356 million. Of the total dividend payments made by PG&E Corporation in 2005, approximately $22 million was paid to Elm Power Corporation, a wholly owned subsidiary of PG&E Corporation. PG&E Corporation did not pay any dividends during 2004.

PG&E CORPORATION

SCHEDULE II — CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2006, 2005 and 2004

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts	Deductions [3]	Balance at End of Period
(in millions)					
Valuation and qualifying accounts deducted from assets:					
2006:					
Allowance for uncollectible accounts [1] [2]	$ 77	$ 2	$ -	$ 29	$ 50
2005:					
Allowance for uncollectible accounts [1] [2]	$ 93	$ 21	$ -	$ 37	$ 77
2004:					
Allowance for uncollectible accounts [1] [2]	$ 68	$ 85	$ -	$ 60	$ 93

(1) Allowance for uncollectible accounts is deducted from “Accounts receivable Customers, net.”

(2) Allowance for uncollectible accounts does not include NEGT.

(3) Deductions consist principally of write-offs, net of collections of receivables previously written off.

PACIFIC GAS AND ELECTRIC COMPANY

SCHEDULE II — CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2006, 2005 and 2004

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts	Deductions [2]	Balance at End of Period
(in millions)					
Valuation and qualifying accounts deducted from assets:					
2006:					
Allowance for uncollectible accounts [1]	$ 77	$ 2	$ -	$ 29	$ 50
2005:					
Allowance for uncollectible accounts [1]	$ 93	$ 21	$ -	$ 37	$ 77
2004:					
Allowance for uncollectible accounts [1]	$ 68	$ 85	$ -	$ 60	$ 93

(1) Allowance for uncollectible accounts is deducted from “Accounts receivable Customers, net.”

(2) Deductions consist principally of write-offs, net of collections of receivables previously written off.

EXHIBIT INDEX

Exhibit Number	Exhibit Description
2.1	Order of the U.S. Bankruptcy Court for the Northern District of California dated December 22, 2003, Confirming Plan of Reorganization of Pacific Gas and Electric Company, including Plan of Reorganization, dated July 31, 2003 as modified by modifications dated November 6, 2003 and December 19, 2003 (Exhibit B to Confirmation Order and Exhibits B and C to the Plan of Reorganization omitted) (incorporated by reference to Pacific Gas and Electric Company's Registration Statement on Form S-3 No. 333-109994, Exhibit 2.1)
2.2	Order of the U.S. Bankruptcy Court for the Northern District of California dated February 27, 2004 Approving Technical Corrections to Plan of Reorganization of Pacific Gas and Electric Company and Supplementing Confirmation Order to Incorporate such Corrections (incorporated by reference to Pacific Gas and Electric Company's Registration Statement on Form S-3 No. 333-109994, Exhibit 2.2)
3.1	Restated Articles of Incorporation of PG&E Corporation effective as of May 29, 2002 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609), Exhibit 3.1)
3.2	Certificate of Determination for PG&E Corporation Series A Preferred Stock filed December 22, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 3.2)
3.3	Bylaws of PG&E Corporation amended as of December 20, 2006
3.4	Restated Articles of Incorporation of Pacific Gas and Electric Company effective as of April 12, 2004 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K filed April 12, 2004 (File No. 1-2348), Exhibit 3)
3.5	Bylaws of Pacific Gas and Electric Company amended as of December 20, 2006
4.1	Indenture, dated as of April 22, 2005, supplementing, amending and restating the Indenture of Mortgage, dated as of March 11, 2004, as supplemented by a First Supplemental Indenture, dated as of March 23, 2004, and a Second Supplemental Indenture, dated as of April 12, 2004, between Pacific Gas and Electric Company and The Bank of New York Trust Company, N.A. (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q filed May 4, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 4.1)
4.2	Indenture related to PG&E Corporation's 7.5% Convertible Subordinated Notes due June 2007, dated as of June 25, 2002, between PG&E Corporation and U.S. Bank, N.A., as Trustee (incorporated by reference to PG&E Corporation's Form 8-K filed June 26, 2002 (File No. 1-12609), Exhibit 99.1).
4.3	Supplemental Indenture related to PG&E Corporation's 9.50% Convertible Subordinated Notes due June 2010, dated as of October 18, 2002, between PG&E Corporation and U.S. Bank, N.A., as Trustee (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2002 (File No. 1-12609), Exhibit 4.1)
4.4	Warrant Agreement, dated as of October 18, 2002, by and among PG&E Corporation, LB I Group Inc., and each other entity named on the signature pages thereto (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2002 (File No. 1-12609), Exhibit 4.2)
10.1	Credit Agreement dated as of April 8, 2005, among Pacific Gas and Electric Company, Citicorp North America, Inc., as administrative agent and a lender, JP Morgan Chase Bank, N.A., as syndication agent and a lender, Barclays Bank PLC, BNP Paribas and Deutsche Bank Securities Inc., as documentation agents and lenders, ABN Amro Bank N.V., Lehman Brothers Bank, FSB, Mellon Bank, N.A., Royal Bank of Canada, The Bank of New York, The Bank of Nova Scotia, UBS Loan Finance LLC, and Union Bank of California, N.A., as senior managing agents, and KBC Bank, NV, Morgan Stanley Bank and William Street Commitment Corporation, as lenders (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q filed May 4, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 10.3)
10.2	First Amendment, dated as of November 30, 2005, to the Credit Agreement among Pacific Gas and Electric Company, Citicorp North America, Inc., as administrative agent and a lender, JPMorgan Chase Bank, N.A., as syndication agent and a lender, Barclays Bank PLC and BNP Paribas as documentation agents and lenders, Deutsche Bank Securities Inc., as documentation agent, and the following other lenders: Deutsche Bank AG New York Branch, ABN Amro Bank N.V., Lehman Brothers Bank, FSB, Mellon Bank, N.A., Royal Bank of Canada, The Bank of New York, UBS Loan Finance LLC, Union Bank of California, N.A., KBC Bank, N.V., Morgan Stanley Bank and William Street Commitment Corporation. (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 10.2)
10.3	Credit Agreement, dated as of December 10, 2004, among PG&E Corporation, BNP Paribas, as administrative agent and a lender, Deutsche Bank Securities, as syndication agent, ABN Amro Bank, N.V., Goldman Sachs Credit Partners L.P., and Union Bank of California, N.A., as documentation agents and lenders, and the following other lenders: Barclays Bank PLC, Citicorp USA, Inc., Deutsche Bank AG New York Branch, JP Morgan Chase Bank, N.A., Lehman Brothers Bank, FSB, Morgan Stanley Bank, Royal Bank of Canada, The Bank of Nova Scotia, and The Bank of New York (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed December 15, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 99)
10.4	First Amendment, dated as of April 8, 2005, to the Credit Agreement dated as of December 10, 2004, among PG&E Corporation, BNP Paribas, as administrative agent and a lender, Deutsche Bank Securities Inc., as syndication agent and a lender, ABN Amro Bank, N.V., Goldman Sachs Credit Partners L.P., and Union Bank of California, N.A., as documentation agents and lenders, and the

following other lenders: Barclays Bank PLC, Citicorp USA, Inc., Deutsche Bank AG New York Branch, JP Morgan Chase Bank, N.A., Lehman Brothers Bank, FSB, Morgan Stanley Bank, Royal Bank of Canada, The Bank of Nova Scotia, KBC Bank N.V., and The Bank of New York (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q filed May 4, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 10.2)

10.5 Master Confirmation dated November 16, 2005, for accelerated share repurchase arrangements between PG&E Corporation and Goldman, Sachs & Co. (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 10.5)

10.6 Settlement Agreement among California Public Utilities Commission, Pacific Gas and Electric Company and PG&E Corporation, dated as of December 19, 2003, together with appendices (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 8-K filed December 22, 2003) (File No. 1-12609 and File No. 1-2348), Exhibit 99)

10.7 Firm Transportation Service Agreement between Pacific Gas and Electric Company and Pacific Gas Transmission Company dated October 26, 1993, Rate Schedule FTS-1, and general terms and conditions (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2003) (File No. 1-12609 and File No. 1-2348), Exhibit 10.4)

10.8 Operating Agreement between Pacific Gas and Electric Company and Pacific Gas Transmission Company dated July 9, 1996 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2003) (File No. 1-12609 and File No. 1-2348), Exhibit 10.5)

10.9 Transmission Control Agreement among the California Independent System Operator (CAISO) and the Participating Transmission Owners, including Pacific Gas and Electric Company, effective as of March 31, 1998, as amended (CAISO, FERC Electric Tariff No. 7) (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.8)

10.10 Operating Agreement, as amended on November 12, 2004, effective as of December 22, 2004, between the State of California Department of Water Resources and Pacific Gas and Electric Company (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.9)

*10.11 PG&E Corporation Supplemental Retirement Savings Plan amended effective as of September 19, 2001, and frozen after December 31, 2004 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004) (File No. 1-12609), Exhibit 10.10)

*10.12 PG&E Corporation Supplemental Retirement Savings Plan effective as of January 1, 2005 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004) (File No. 1-12609), Exhibit 10.11)

*10.13 Letter regarding Compensation Arrangement between PG&E Corporation and Peter Darbee effective July 1, 2003 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609), Exhibit 10.4)

* 10.14 Letter regarding Compensation Arrangement between PG&E Corporation and Thomas B. King dated June 18, 2003 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609), Exhibit 10.3)

*10.15 Retention Agreement between PG&E Corporation and Thomas B. King dated August 31, 2006 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2006 (File No. 1-12609), Exhibit 10.2)

*10.16 Letter regarding Compensation Arrangement between Pacific Gas and Electric Company and William T. Morrow dated June 20, 2006 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2006 (File No. 1-12609), Exhibit 10.1 **)**

*10.17 Letter regarding Compensation Arrangement between PG&E Corporation and Rand L. Rosenberg dated October 19, 2005 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005) (File No. 1-12609), Exhibit 10.18)

*10.18 Letter regarding Compensation Arrangement between PG&E Corporation and Hyun Park dated October 10, 2006

*10.19 PG&E Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, effective as of January 1, 2005 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004) (File No. 1-12609), Exhibit 10.17)

*10.20 Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2007

*10.21 Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.23)

*10.22 Supplemental Executive Retirement Plan of the Pacific Gas and Electric Company amended effective as of December 31, 2004, and frozen as of January 1, 2005 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004) (File No. 1-2348), Exhibit 10.20)

*10.23 Supplemental Executive Retirement Plan of PG&E Corporation as amended effective as of January 1, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005) (File No. 1-2348), Exhibit 10.27)

*10.24 Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Bruce R. Worthington dated December 20, 2002 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.37.2)

*10.25

Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Bruce R. Worthington dated

April 18, 2003 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609), Exhibit 10.2.5)

*10.26 Pacific Gas and Electric Company Relocation Assistance Program for Officers (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for fiscal year 1989 (File No. 1-2348), Exhibit 10.16)

*10.27 Postretirement Life Insurance Plan of the Pacific Gas and Electric Company (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for fiscal year 1991 (File No. 1-2348), Exhibit 10.16)

*10.28 PG&E Corporation Non-Employee Director Stock Incentive Plan (a component of the PG&E Corporation Long-Term Incentive Program) as amended effective as of July 1, 2004 (reflecting amendments adopted by the PG&E Corporation Board of Directors on June 16, 2004 set forth in resolutions filed as Exhibit 10.3 to PG&E Corporation's and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004 **)** (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.27)

*10.29 Resolution of the PG&E Corporation Board of Directors dated June 16, 2004, adopting director compensation arrangement (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12609 and File No. 12348), Exhibit 10.1)

*10.30 Resolution of the Pacific Gas and Electric Company Board of Directors dated June 16, 2004, adopting director compensation arrangement (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12609 and File No. 12348), Exhibit 10.2)

*10.31 Resolution of the PG&E Corporation Board of Directors dated December 20, 2006, adopting director compensation arrangement effective January 1, 2007

*10.32 Resolution of the Pacific Gas and Electric Company Board of Directors dated December 20, 2006, adopting director compensation arrangement effective January 1, 2007

*10.33 PG&E Corporation 2006 Long-Term Incentive Plan, as amended on February 15, 2006 (with respect to change in control provisions) and December 20, 2006 (with respect to Section 7 governing nondiscretionary awards to non-employee directors)

*10.34 PG&E Corporation Long-Term Incentive Program (including the PG&E Corporation Stock Option Plan and Performance Unit Plan), as amended May 16, 2001, (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2001 (File No. 1-12609), Exhibit 10)

*10.35 Form of Restricted Stock Award Agreement for 2003 grants made under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.46)

*10.36 Form of Restricted Stock Award Agreement for 2004 grants made under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2003 (File No. 1-12609), Exhibit 10.37)

*10.37 Form of Restricted Stock Agreement for 2005 grants under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 6, 2005 (File No. 12609 and File No. 1-2348), Exhibit 99.3)

*10.38 Form of Restricted Stock Agreement for 2006 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 9, 2006, Exhibit 99.1)

*10.39 Form of Restricted Stock Agreement for 2007 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (reflecting amendments to the PG&E Corporation 2006 Long-Term Incentive Plan made on February 15, 2006)

*10.40 Form of Non-Qualified Stock Option Agreement under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 6, 2005 (File No. 12609 and File No. 1-2348), Exhibit 99.1)

*10.41 Form of Performance Share Award Agreement for 2004 grants under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2003 (File No. 1-12609), Exhibit 10.38)

*10.42 Form of Performance Share Agreement for 2005 grants under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 6, 2005 (File No. 12609 and File No. 1-2348), Exhibit 99.2)

*10.43 Form of Performance Share Agreement for 2006 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 9, 2006, Exhibit 99.2)

*10.44 Form of Performance Share Agreement for 2007 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (reflecting amendments to the PG&E Corporation 2006 Long-Term Incentive Plan made on February 15, 2006)

*10.45 PG&E Corporation Executive Stock Ownership Program Guidelines dated as of February 19, 2003 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609) Exhibit 10.2)

*10.46 PG&E Corporation Executive Stock Ownership Program Guidelines as amended February 15, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005 (File No. 1-12609), Exhibit 10.46)

*10.47 PG&E Corporation Officer Severance Policy, as amended effective as of January 1, 2005 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.37)

*10.48
PG&E Corporation Officer Severance Policy, as amended effective as of February 15, 2006 (incorporated by reference to PG&E

	Corporation's Form 10-K for the year ended December 31, 2005 (File No. 1-12609), Exhibit 10.48)
*10.49	PG&E Corporation Golden Parachute Restriction Policy effective as of February 15, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005 (File No. 1-12609), Exhibit 10.49)
*10.50	PG&E Corporation Director Grantor Trust Agreement dated April 1, 1998 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 1998 (File No. 1-12609), Exhibit 10.1)
*10.51	PG&E Corporation Officer Grantor Trust Agreement dated April 1, 1998, as updated effective January 1, 2005 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.39)
*10.52	Resolution of the Board of Directors of PG&E Corporation regarding indemnification of officers and directors dated December 18, 1996 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.40)
*10.53	Resolution of the Board of Directors of Pacific Gas and Electric Company regarding indemnification of officers and directors dated July 19, 1995 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-2348), Exhibit 10.41)
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
13	The following portions of the 2006 Annual Report to Shareholders of PG&E Corporation and Pacific Gas and Electric Company are included: "Selected Financial Data," "Management's Discussion and Analysis of Financial Condition and Results of Operations," financial statements of PG&E Corporation entitled "Consolidated Statements of Income," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Shareholders' Equity," financial statements of Pacific Gas and Electric Company entitled "Consolidated Statements of Income," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Shareholders' Equity," "Notes to the Consolidated Financial Statements," and "Quarterly Consolidated Financial Data (Unaudited)," "Management's Report on Internal Control Over Financial Reporting," "Report of Independent Registered Public Accounting Firm," and "Report of Independent Registered Public Accounting Firm."
21	Subsidiaries of the Registrant
23	Consent of Independent Registered Public Accounting Firm (Deloitte & Touche LLP)
24.1	Resolutions of the Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company authorizing the execution of the Form 10-K
24.2	Powers of Attorney
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

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

Exhibit 3.3

Bylaws
of
PG&E Corporation
amended as of December 20, 2006

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. **Shareholder Action by Written Consent.** Subject to Section 603 of the California Corporations Code, any action which, under any provision of the California Corporations Code, may be taken at any annual or special meeting of shareholders may be taken without a meeting and without prior notice if a consent in writing, setting forth the action so taken, shall be signed by the holders of outstanding shares having not less than the minimum number of votes that would be necessary to authorize or take such action at a meeting at which all shares entitled to vote thereon were present and voted.

Any party seeking to solicit written consent from shareholders to take corporate action must deliver a notice to the Corporate Secretary of the Corporation which requests the Board of Directors to set a record date for determining shareholders entitled to give such consent. Such written request must set forth as to each matter the party proposes for shareholder action by written consents (a) a brief description of the matter and (b) the class and number of shares of the Corporation that are beneficially owned by the requesting party. Within ten days of receiving the request in the proper form, the Board shall set a record date for the taking of such action by written consent in accordance with California Corporations Code Section 701 and Article IV, Section 1 of these Bylaws. If the Board fails to set a record date within such ten-day period, the record date for determining shareholders entitled to give the written consent for the matters specified in the notice shall be the day on which the first written consent is given in accordance with California Corporations Code Section 701.

Each written consent delivered to the Corporation must set forth (a) the action sought to be taken, (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, (d) the name and address of the proxyholder authorized by the shareholder to give such written consent, if applicable, and (d) any material interest of the shareholder or proxyholder in the action sought to be taken.

Consents to corporate action shall be valid for a maximum of sixty days after the date of the earliest dated consent delivered to the Corporation. Consents may be revoked by written notice (i) to the Corporation, (ii) to the shareholder or shareholders soliciting consents or soliciting revocations in opposition to action by consent proposed by the Corporation (the "Soliciting Shareholders"), or (iii) to a proxy solicitor or other agent designated by the Corporation or the Soliciting Shareholders.

Within three business days after receipt of the earliest dated consent solicited by the Soliciting Shareholders and delivered to the Corporation in the manner provided in California Corporations Code Section 603 or the determination by the Board of Directors of the Corporation that the Corporation should seek corporate action by written consent, as the case may be, the Corporate Secretary shall engage nationally recognized independent inspectors of elections for the purpose of performing a ministerial review of the validity of the consents and revocations. The cost of retaining inspectors of election shall be borne by the Corporation.

Consents and revocations shall be delivered to the inspectors upon receipt by the Corporation, the Soliciting Shareholders or their proxy solicitors, or other designated agents. As soon as consents and revocations are received, the inspectors shall review the consents and revocations and shall maintain a count of the number of valid and unrevoked consents. The inspectors shall keep such count confidential and shall not reveal the count to the Corporation, the Soliciting Shareholder or their representatives, or any other entity. As soon as practicable after the earlier of (i) sixty days after the date of the earliest dated consent delivered to the Corporation in the manner provided in California Corporations Code Section 603, or (ii) a written request therefor by the Corporation or the Soliciting Shareholders (whichever is soliciting consents), notice of which request shall be given to the party opposing the solicitation of consents, if any, which request shall state that the Corporation or Soliciting Shareholders, as the case may be, have a good faith belief that the requisite number of valid and unrevoked consents to authorize or take the action specified in the consents has been received in accordance with these Bylaws, the inspectors shall issue a preliminary report to the Corporation and the Soliciting Shareholders stating: (a) the number of valid consents, (b) the number of valid revocations, (c) the number of valid and unrevoked consents, (d) the number of invalid consents, (e) the number of invalid revocations, and (f) whether, based on their preliminary count, the requisite number of valid and unrevoked consents has been obtained to authorize or take the action specified in the consents.

Unless the Corporation and the Soliciting Shareholders shall agree to a shorter or longer period, the Corporation and the Soliciting Shareholders shall have forty-eight hours to review the consents and revocations and to advise the inspectors and the opposing party in writing as to whether they intend to challenge the preliminary report of the inspectors. If no written notice of an intention to challenge the preliminary report is received within forty-eight hours after the inspectors' issuance of the preliminary report, the inspectors shall issue to the Corporation and the Soliciting Shareholders their final report containing the information from the inspectors' determination with respect to whether the requisite number of valid and unrevoked consents was obtained to authorize and take the action specified in the consents. If the Corporation or the Soliciting Shareholders issue written notice of an intention to challenge the inspectors' preliminary report within forty-eight hours after the issuance of that report, a challenge session shall be scheduled by the inspectors as promptly as practicable. A transcript of the challenge session shall be recorded by a certified court reporter. Following completion of the challenge session, the inspectors shall as promptly as practicable issue their final report to the Soliciting Shareholders and the Corporation, which report shall contain the information included in the preliminary report, plus all changes in the vote totals as a result of the challenge and a certification of whether the requisite number of valid and unrevoked consents was obtained to authorize or take the action specified in the consents. A copy of the final report of the inspectors shall be included in the book in which the proceedings of meetings of shareholders are recorded.

Unless the consent of all shareholders entitled to vote have been solicited in writing, the Corporation shall give prompt notice to the shareholders in accordance with

California Corporations Code Section 603 of the results of any consent solicitation or the taking of the corporate action without a meeting and by less than unanimous written consent.

Article II.
DIRECTORS.

1. **Number** . As stated in paragraph I of Article Third of this Corporation's Articles of Incorporation, the Board of Directors of this Corporation shall consist of such number of directors, not less than seven (7) nor more than thirteen (13). 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, a Chief Financial Officer, a General Counsel, one or more Vice Presidents, a Corporate Secretary and one or more Assistant Corporate Secretaries, a Treasurer and one or more Assistant Treasurers, 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 and of the Directors, and shall preside at all meetings 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 the President's 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. **Chief Financial Officer** . The Chief Financial Officer shall be responsible for the overall management of the financial affairs of the Corporation. The Chief Financial Officer shall render a statement of the Corporation's financial condition and an account of all transactions whenever requested by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, or the President.

The Chief Financial Officer 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.

7. **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.

8. **Vice Presidents** . Each Vice President, if those offices are filled, 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, the Chairman of the Board, the Vice Chairman of the Board, or the President may confer a special title upon any Vice President.

9. **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.

10. **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 depositaries 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, the Chief Financial Officer, or the Bylaws.

The Assistant Treasurers 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, the Chief Financial Officer, or the Treasurer. In the absence or disability of the Treasurer, the Treasurer's duties shall be performed by an Assistant Treasurer.

11. **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, the Chief Financial Officer, 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. Certificates; Direct Registration System . Shares of the Corporation's capital stock may be certificated or uncertificated, as provided under California law. Any certificates that are issued shall be signed in the name of the Corporation by the Chairman of the Board, the Vice Chairman of the Board, the President, or a Vice President and by the Chief Financial Officer, an Assistant Treasurer, the Corporate Secretary, or an Assistant Secretary, certifying the number of shares and the class or series of shares owned by the shareholder. Any or all of the signatures on the certificate may be a facsimile. In case any officer, Transfer Agent, or Registrar who has signed or whose facsimile signature has been placed upon a certificate shall have ceased to be such officer, Transfer Agent, or Registrar before such certificate is issued, it may be issued by the Corporation with the same effect as if such person were an officer, Transfer Agent, or Registrar at the date of issue. Shares of the Corporation’s capital stock may also be evidenced by registration in the holder’s name in uncertificated, book-entry form on the books of the Corporation in accordance with a direct registration system approved by the Securities and Exchange Commission and by the New York Stock Exchange or any securities exchange on which the stock of the Corporation may from time to time be traded.

3. Transfers of shares of stock of the Corporation shall be made by the Transfer Agent and Registrar on the books of the Corporation after receipt of a request with proper evidence of succession, assignment, or authority to transfer by the record holder of such stock, or by an attorney lawfully constituted in writing, and in the case of stock represented by a certificate, upon surrender of the certificate. 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 shares of stock of the Corporation, and to appoint and remove Transfer Agents and Registrars of transfers.

4. **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 (or uncertificated shares in lieu of 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.

Exhibit 3.5

Bylaws
of

Pacific Gas and Electric Company

amended as of December 20, 2006

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 eleven (11) 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 depositaries 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. **Certificates; Direct Registration System.** Shares of the Corporation's stock may be certificated or uncertificated, as provided under California law. Any certificates that are issued shall be signed in the name of the Corporation by the Chairman of the Board, the Vice Chairman of the Board, the President, or a Vice President and by the Chief Financial Officer, an Assistant Treasurer, the Corporate Secretary, or an Assistant Secretary, certifying the number of shares and the class or series of shares owned by the shareholder. Any or all of the signatures on the certificate may be a facsimile. In case any officer, Transfer Agent, or Registrar who has signed or whose facsimile signature has been placed upon a certificate shall have ceased to be such officer, Transfer Agent, or Registrar before such certificate is issued, it may be issued by the Corporation with the same effect as if such person were an officer, Transfer Agent, or Registrar at the date of issue. Shares of the Corporation’s capital stock may also be evidenced by registration in the holder’s name in uncertificated, book-entry form on the books of the Corporation in accordance with a direct registration system approved by the Securities and Exchange Commission and by the American Stock Exchange or any securities exchange on which the stock of the Corporation may from time to time be traded.

Transfers of shares of stock of the Corporation shall be made by the Transfer Agent and Registrar on the books of the Corporation only after receipt of a request with proper evidence of succession, assignment, or authority to transfer by the record holder of such stock, or by an attorney lawfully constituted in writing, and in the case of stock represented by a certificate, upon surrender of the certificate. 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 (or uncertificated shares in lieu of 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.

[PG&E Corporation Letterhead]

Exhibit 10.18

October 10, 2006

Mr. Hyun Park
15 Magnolia Drive
Purchase, NY 10577

Dear Hyun:

On behalf of PG&E Corporation, I am pleased to extend a revised invitation to you to join our organization as Senior Vice President and General Counsel, reporting to me.

Your initial total compensation package will consist of the following:

1. An annual base salary of $475,000 ($39,583.33/month) subject to possible increases through our annual salary review plan.

2. A target incentive of $261,250 (55% of your base salary) in an annual short-term incentive plan under which your actual incentive dollars may range from zero to $522,500 based on performance relative to established goals. For 2006, this incentive will be prorated for the number of months worked from your date of hire and will be payable in 2007.

3. A one-time bonus of $225,000 payable within 60 days of your date of hire, subject to normal tax withholdings. Should you voluntarily leave the company (other than for good reason in connection with a change in control) or should your employment be terminated for cause within two years of your date of hire, a prorated amount of this bonus must be refunded to the company.

4. Participation in the PG&E Corporation Long-Term Incentive Plan (LTIP) as a band 2 officer. Grants under the LTIP are currently split equally between restricted stock and performance shares, and are generally made annually on the first business day of the year. Your initial LTIP grant will be made on your date of hire, and will have an estimated value of $1,000,000. This estimated value is used only for the purpose of determining the number of shares for your grant, which will be based on the closing price of PG&E Corporation common stock (PCG) on your date of hire. You will also receive a 2007 LTIP grant with an estimated value of $800,000. That grant will be made on the first business day of January 2007, and will be based on the closing price of PCG on that day. The ultimate value that you realize from these grants will depend upon your employment status and the performance of PG&E Corporation common stock.

5. A payment of $1,500,000 to be credited to an account within the PG&E Corporation Supplemental Retirement Savings Plan (SRSP), a non-qualified deferred compensation plan. The payment will be made in two installments as follows: $1,000,000 on your first service anniversary, and $500,000 on your second service anniversary. Should you terminate prior to the payment of an installment, that installment as well as any remaining installment will be forfeited. The credited funds will be allocated to the PG&E Phantom Stock Fund; will not be eligible for incentive purposes under the PG&E Corporation Executive Stock Ownership Program; and may not be reallocated to other investment funds within the SRSP. Distribution of credited funds will be made in accordance with your elections and the administrative provisions governing the SRSP.

6. Participation in the PG&E Corporation Supplemental Executive Retirement Plan (SERP). The basic benefit payable from the SERP at retirement is a monthly annuity equal to the product of 1.7% x [average of the three highest years' combination of salary and annual incentive for the last ten years of service] x years of credited service x 1/12.

7. Participation in the PG&E Corporation Retirement Savings Plan (RSP), a 401(k) defined contribution plan. You will be eligible to contribute as much as 20% of your salary on either a pre-tax or after-tax basis, subject to legal limits. After your first year of service, we will match contributions you make, up to 3% of your salary, at 75 cents on each dollar contributed for the second and third years of your employment. Thereafter, we will match contributions up to 6% of your salary at 75 cents on each dollar contributed.

8. Participation in the PG&E Corporation Supplemental Retirement Savings Plan (SRSP), a non-qualified deferred compensation plan. You may elect to defer payment of some of your compensation on a pre-tax basis. We will provide you with the full matching contributions that cannot be provided through the RSP due to legal limitations imposed on highly compensated employees.

9. As a result of your officer level (officer band 2), you will become an eligible participant in the Executive Stock Ownership Program effective January 1, 2007. As an ancillary benefit to that program, you will also be eligible to receive financial counseling from The AYCO Company at a subsidized rate to assist you in your understanding of our compensation and benefits programs and how those programs can help you to achieve financial security.

10. You will be assumed to have met the service requirements associated with eligibility for full benefits under the PG&E Corporation Officer Severance Policy.

11. Participation in a cafeteria-style benefits program that permits you to select coverage tailored to your personal needs and circumstances. The benefits you elect will be effective the first of the month following the date of your hire.

12. PG&E Corporation also offers employees an initial allocation of Paid Time Off (PTO) upon hire. Future allocations of PTO are made each year on January 1, and are based on your date of hire and amount worked in the preceding year. For example, by starting work in November and working full-time for the remainder of 2006, you will be eligible for 100 hours of PTO upon hire and 34 hours on January 1, 2007. Thereafter, you will accrue PTO at rate of approximately 17 hours per month (200 hours per year), provided that you work full-time for the month. In addition, PG&E Corporation recognizes 10 paid company holidays annually and provides 3 floating holidays immediately upon hire and at the beginning of each year.

13. An annual perquisite allowance of $25,000 to be used in lieu of individual authorizations for c ars and memberships in clubs and civic organizations. For 2006, you will receive 50% of this amount ($12,500).

14. A comprehensive executive relocation assistance package, including: (1) the reimbursement of closing costs on the sale of your current residence, contingent upon using a PG&E-designated relocation company and purchasing a new residence within 18 months of your date of hire, subject to any applicable IRS restrictions; (2) the move of your household goods, including 60 days of storage and the movement of the goods out of storage; (3) a lump sum payment of $10,000 payable within 60 days of your date of hire; and (4) up to two exploratory trips for you and your family. In addition, you will be provided with temporary housing and regular return-home trips to New York (business class or in the event of no business class, first class), no more than weekly, through June 2007. The costs of such housing and travel will be grossed-up for applicable taxes.

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

I look forward to your joining our team and believe you will make a strong contribution to the achievement of our being the leading utility in the United States. I would appreciate receiving your written acceptance of this offer as soon as possible. Please call me at any time if you have questions.

Sincerely,

PETER A. DARBEE

PETER A. DARBEE
Chairman of the Board, Chief Executive Officer, and President

This is to confirm my acceptance of PG&E Corporation’s offer as Senior Vice President and General Counsel outlined above.

HYUN PARK 10/16/06

(Signature and Date)

Exhibit 10.20

2007 OFFICER SHORT-TERM INCENTIVE PLAN

On December 20, 2006, the Nominating, Compensation, and Governance Committee (Committee) of the PG&E Corporation Board of Directors established the structure of the PG&E Corporation 2007 Short-Term Incentive Plan (STIP), under which officers of PG&E Corporation and Pacific Gas and Electric Company (Utility) are provided an opportunity to receive annual incentive cash payments. Corporate financial performance, as measured by corporate earnings from operations, will account for 50 percent of the incentive, 20 percent of the incentive will be based on customer satisfaction indices, 20 percent of the incentive will be based on the Utility's success in implementing its strategy to achieve operational excellence and improved customer service, 5 percent will be based on the results of an employee opinion survey measuring employee engagement, and the remaining 5 percent will be based on achieving safety standards.

At its meeting on February 21, 2007, the Committee approved the specific performance scale that will be used to determine the extent to which the corporate financial objective, as measured by earnings from operations, has been met. The Committee used the same methodology to establish the performance scale for the corporate financial performance portion of the 2007 STIP as was used for the 2006 STIP. The corporate financial performance measure is based on PG&E Corporation's budgeted earnings from operations that were previously approved by the Board of Directors, consistent with the basis for reporting and guidance to the financial community. As with previous earnings performance scales, unbudgeted items impacting comparability such as changes in accounting methods, workforce restructuring, and one-time occurrences will be excluded.

The Committee also approved the 2007 performance targets for each of the four other measures set forth in the table below. The 2006 performance results for each measure are included for comparative purposes.

2007 STIP Performance Targets [1]

Measure	Relative Weight	2006 Results	2007 Target
Customer Satisfaction (Residential & Business) [2]	20%	100	676
Business Transformation Index [3]	20%	N/A	1.0
Employee Survey (Premier) Index [4]	5%	64.0%	66.0%
Occupational Safety and Health Administration (OSHA) Recordable Injury Rate [5]	5%	12.9% reduction	15% reduction

1. As explained above, 50% of the STIP award will be based on achievement of corporate earnings from operations targets.

2. This measure reflects a weighted composite of the overall customer satisfaction indices of the Utility's residential and business customers as reported by the J.D. Power Residential Survey and the J.D. Power Business Survey. For 2006, the residential customers' and business customers' scores were weighted equally. In an effort to enhance the focus on improving residential customer satisfaction, which has been lower than business customer satisfaction, for the 2007 target the weighting of the residential customers' score will be increased to 60% and the weighting of the business customers' score will be lowered to 40%. In addition, for 2007, J.D. Power and Associates has changed the scale used to report results from the J.D. Power Survey from a scale that attempted to center the industry average score at approximately 100 to a 1,000 point scale. By way of comparison, results for 2006 would have been 678 under the new 1000 point scale based on equally weighted scores and results for 2006 would have been 673 based on the revised weightings. The 2007 target may be adjusted to reflect changes in the J.D. Power industry average scores, which are expected by mid-year 2007.

3. The Business Transformation Index is comprised of five measurement points that define success in achieving key Business Transformation operational, financial, and post-implementation objectives. The five measurement points are (1) overall Business Transformation cost performance in comparison to budgeted amounts, (2) overall business transformation benefit performance in comparison to planned/budgeted amounts, (3) new business customer connection performance for cycle time and number of customer commitments met, (4) SmartMeter ^{TM} project performance for number of meters installed and activated, and (5) the extent to which core business transformation initiatives are implemented compared to planned schedule and scope of initiatives.

4. The Premier Survey is the primary tool used to measure employee engagement at PG&E Corporation and the Utility. The employee index is designed around 15 key drivers of employee engagement. The average overall employee survey index score provides a comprehensive metric that is derived by adding the percent of favorable responses from all 40 core survey items (all of which fall into one of 15 broader topical areas), and then dividing the total sum by 40.

5. An “OSHA Recordable” is an occupational (job-related) injury or illness that requires medical treatment beyond first aid, or results in work restrictions, death or loss of consciousness. The “OSHA Recordable Rate” is the number of OSHA Recordables for every 200,000 hours worked, or for approximately 100 employees. This metric measures the percentage reduction in the Utility’s OSHA Recordable rate from the prior year.

The Committee has full discretion as to the determination of final officer STIP awards for 2007 performance.

Exhibit 10.31

Director Compensation

RESOLUTION OF THE
BOARD OF DIRECTORS OF
PG&E CORPORATION

December 20, 2006

BE IT RESOLVED that, effective January 1, 2007, directors who are not employees of this corporation or Pacific Gas and Electric Company ("non-employee directors") shall be paid a retainer of $12,500 per calendar quarter, which shall be in addition to fees paid for attendance at Board and Board committee meetings; and

BE IT FURTHER RESOLVED that, effective January 1, 2007, the non-employee director who serves as lead director shall be paid an additional retainer of $12,500 per calendar quarter; and

BE IT FURTHER RESOLVED that, effective January 1, 2007, the non-employee directors who are duly appointed to chair the Finance Committee, the Nominating, Compensation, and Governance Committee, and the Public Policy Committee of this Board shall be paid an additional retainer of $1,875 per calendar quarter, and the non-employee directors who are duly appointed to chair the Audit Committee and the Nominating, Compensation, and Governance Committee of this Board shall be paid an additional retainer of $12,500 per calendar quarter; provided, however, that a non-employee director duly appointed to chair one of the foregoing committees shall not be paid an additional retainer for any calendar quarter during which such director also serves as lead director; and

BE IT FURTHER RESOLVED that, effective January 1, 2007, non-employee directors shall be paid a fee of $1,750 for each meeting of the Board and for each meeting of a Board committee attended; provided, however, that non-employee directors who are members of the Audit Committee shall be paid a fee of $2,750 for each meeting of the Audit Committee attended; and

BE IT FURTHER RESOLVED that any non-employee director may participate in a Directors' Voluntary Stock Purchase Program by instructing the Corporate Secretary to withhold an amount equal to but not less than 20 percent of his or her meeting fees and/or quarterly retainers for the purpose of acquiring shares of this corporation's common stock on behalf of said director, provided that once a non-employee director has so instructed the Corporate Secretary, said director may not modify or discontinue such instruction for at least 12 calendar months; and

BE IT FURTHER RESOLVED that non-employee directors shall be eligible to participate in the PG&E Corporation 2006 Long-Term Incentive Plan under the terms and conditions of that Plan, as adopted by this Board of Directors and as may be amended from time to time; and

BE IT FURTHER RESOLVED that members of this Board shall be reimbursed for reasonable expenses incurred in attending Board or committee meetings; and

BE IT FURTHER RESOLVED that, effective January 1, 2007, the resolution on this subject adopted by the Board of Directors on June 16, 2004, is hereby superseded.

Exhibit 10.32

Director Compensation

RESOLUTION OF THE
BOARD OF DIRECTORS OF
PACIFIC GAS AND ELECTRIC COMPANY

December 20, 2006

BE IT RESOLVED that, effective January 1, 2007, directors who are not employees of this company or PG&E Corporation ("non-employee directors") shall be paid a retainer of $12,500 per calendar quarter which shall be in addition to any fees paid for attendance at Board and Board committee meetings; provided, however, that a non-employee director shall not be paid a retainer by this company for any calendar quarter during which such director also serves as a director or advisory director of PG&E Corporation; and

BE IT FURTHER RESOLVED that, effective January 1, 2007, the non-employee director who serves as lead director shall be paid an additional retainer of $12,500 per calendar quarter; provided, however, that a non-employee director who serves as lead director shall not be paid an additional retainer by this company for any calendar quarter during which such director also serves as lead director of the PG&E Corporation Board of Directors; and

BE IT FURTHER RESOLVED that, effective January 1, 2007, the non-employee directors who are duly appointed to chair the committees of this Board shall be paid an additional retainer of $1,875 per calendar quarter or, in the case of the chair of the Audit Committee, an additional retainer of $12,500 per calendar quarter; provided, however, that (1) a non-employee director duly appointed to chair a committee of this Board shall not be paid an additional retainer by this company for any calendar quarter during which such director also serves as chair of the corresponding committee of the PG&E Corporation Board of Directors, and (2) a non-employee director duly appointed to chair a committee of this Board shall not be paid an additional retainer for any calendar quarter during which such director also serves as lead director; and

BE IT FURTHER RESOLVED that, effective January 1, 2007, non-employee directors attending any meeting of the Board not held concurrently or sequentially with a meeting of the Board of Directors of PG&E Corporation, or any meeting of a Board committee not held

concurrently or sequentially with a meeting of the corresponding committee of the PG&E Corporation Board, shall be paid a fee of $1,750 for each such meeting attended; provided, however, that non-employee directors attending any meeting of the Audit Committee of this Board which is not held concurrently or sequentially with a meeting of the Audit Committee of the PG&E Corporation Board, shall be paid a fee of $2,750 for each such meeting attended; and

BE IT FURTHER RESOLVED that any non-employee director may participate in a Directors' Voluntary Stock Purchase Program by instructing the Corporate Secretary to withhold an amount equal to but not less than 20 percent of his or her meeting fees and/or quarterly retainers for the purpose of acquiring shares of PG&E Corporation common stock on behalf of said director, provided that once a non-employee director has so instructed the Corporate Secretary, said director may not modify or discontinue such instruction for at least 12 calendar months; and

BE IT FURTHER RESOLVED that members of this Board shall be reimbursed for reasonable expenses incurred in attending Board or committee meetings; and

BE IT FURTHER RESOLVED that, effective January 1, 2007, the resolution on this subject adopted by the Board of Directors on June 16, 2004, is hereby superseded.

Exhibit 10.33

PG&E Corporation

2006 Long-Term Incentive Plan

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PG&E Corporation
2006 Long-Term Incentive Plan

1. **Establishment, Purpose and Term of Plan .**

1.1 **Establishment .** The PG&E Corporation 2006 Long-Term Incentive Plan (the " ***Plan*** ") is hereby established effective as of January 1, 2006 (the " ***Effective Date*** "), provided it has been approved by the shareholders of the Company.

1.2 **Purpose .** The purpose of the Plan is to advance the interests of the Participating Company Group and its shareholders by providing an incentive to attract and retain the best qualified personnel to perform services for the Participating Company Group, by motivating such persons to contribute to the growth and profitability of the Participating Company Group, by aligning their interests with interests of the Company's shareholders, and by rewarding such persons for their services by tying a significant portion of their total compensation package to the success of the Company. The Plan seeks to achieve this purpose by providing for Awards in the form of Options, Stock Appreciation Rights, Restricted Stock Awards, Performance Shares, Performance Units, Restricted Stock Units, Deferred Compensation Awards and other Stock-Based Awards as described below.

1.3 **Term of Plan.** The Plan shall continue in effect until the earlier of its termination by the Board or the date on which all of the shares of Stock available for issuance under the Plan have been issued and all restrictions on such shares under the terms of the Plan and the agreements evidencing Awards granted under the Plan have lapsed. However, all Awards shall be granted, if at all, within ten (10) years from the Effective Date. Moreover, Incentive Stock Options shall not be granted later than ten (10) years from the date of shareholder approval of the Plan.

2. **Definitions and Construction .**

2.1 **Definitions.** Whenever used herein, the following terms shall have their respective meanings set forth below:

(a) " ***Affiliate*** " means (i) an entity, other than a Parent Corporation, that directly, or indirectly through one or more intermediary entities, controls the Company or (ii) an entity, other than a Subsidiary Corporation, that is controlled by the Company directly, or indirectly through one or more intermediary entities. For this purpose, the term "control" (including the term "controlled by") means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of the relevant entity, whether through the ownership of voting securities, by contract or otherwise; or shall have such other meaning assigned such term for the purposes of registration on Form S-8 under the Securities Act.

(b) *" **Award** "* means any Option, SAR, Restricted Stock Award, Performance Share, Performance Unit, Restricted Stock Unit or Deferred Compensation Award or other Stock-Based Award granted under the Plan.

(c) *" **Award Agreement** "* means a written agreement between the Company and a Participant setting forth the terms, conditions and restrictions of the Award granted to the Participant.

(d) *" **Board** "* means the Board of Directors of the Company.

(e) *" **Change in Control** "* means, unless otherwise defined by the Participant's Award Agreement or contract of employment or service, the occurrence of any of the following:

(i) any "person" (as such term is used in Sections 13(d) and 14(d) of the Exchange Act, but excluding any benefit plan for Employees or any trustee, agent or other fiduciary for any such plan acting in such person's capacity as such fiduciary), directly or indirectly, becomes the "beneficial owner" (as defined in Rule 13d-3 promulgated under the Exchange Act), of stock of the Company representing twenty percent (20%) or more of the combined voting power of the Company's then outstanding voting stock; or

(ii) during any two consecutive years, individuals who at the beginning of such period constitute the Board cease for any reason to constitute at least a majority of the Board, unless the election, or the nomination for election by the shareholders of the Company, of each new Director was approved by a vote of at least two-thirds (2/3) of the Directors then still in office who were Directors at the beginning of the period; or

(iii) the consummation of any consolidation or merger of the Company other than a merger or consolidation which would result in the voting stock of the Company outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting stock of the surviving entity or any parent of such surviving entity) at least seventy percent (70%) of the Combined Voting Power of the Company, such surviving entity or the parent of such surviving entity outstanding immediately after the merger or consolidation; or

(iv) the approval of the Shareholders of the Company of any (1) sale, lease, exchange or other transfer (in one or a series of related transactions) of all or substantially all of the assets of the Company, or (2) any plan or proposal for the liquidation or dissolution of the Company.

For purposes of paragraph (iii), the term ***"Combined Voting Power"*** shall mean the combined voting power of the Company's or other relevant entity's then outstanding voting stock.

(f) *" **Code** "* means the Internal Revenue Code of 1986, as amended, and any applicable regulations promulgated thereunder.

(g) *" **Committee** "* means the Nominating, Compensation, and Governance Committee or other committee of the Board duly appointed to administer the Plan and having

such powers as shall be specified by the Board. If no committee of the Board has been appointed to administer the Plan, the Board shall exercise all of the powers of the Committee granted herein, and, in any event, the Board may in its discretion exercise any or all of such powers.

(h) "***Company***" means PG&E Corporation, a California corporation, or any successor corporation thereto.

(i) "***Consultant***" means a person engaged to provide consulting or advisory services (other than as an Employee or a member of the Board) to a Participating Company, provided that the identity of such person, the nature of such services or the entity to which such services are provided would not preclude the Company from offering or selling securities to such person pursuant to the Plan in reliance on registration on a Form S-8 Registration Statement under the Securities Act.

(j) "***Deferred Compensation Award***" means an award of Stock Units granted to a Participant pursuant to Section 12 of the Plan.

(k) "***Director***" means a member of the Board.

(l) "***Disability***" means the permanent and total disability of the Participant, within the meaning of Section 22(e)(3) of the Code.

(m) "***Dividend Equivalent***" means a credit, made at the discretion of the Committee or as otherwise provided by the Plan, to the account of a Participant in an amount equal to the cash dividends paid on one share of Stock for each share of Stock represented by an Award held by such Participant.

(n) "***Employee***" means any person treated as an employee (including an Officer or a member of the Board who is also treated as an employee) in the records of a Participating Company and, with respect to any Incentive Stock Option granted to such person, who is an employee for purposes of Section 422 of the Code; provided, however, that neither service as a member of the Board nor payment of a director's fee shall be sufficient to constitute employment for purposes of the Plan. The Company shall determine in good faith and in the exercise of its discretion whether an individual has become or has ceased to be an Employee and the effective date of such individual's employment or termination of employment, as the case may be. For purposes of an individual's rights, if any, under the Plan as of the time of the Company's determination, all such determinations by the Company shall be final, binding and conclusive, notwithstanding that the Company or any court of law or governmental agency subsequently makes a contrary determination.

(o) "***Exchange Act***" means the Securities Exchange Act of 1934, as amended.

(p) "***Fair Market Value***" means, as of any date, the value of a share of Stock or other property as determined by the Committee, in its discretion, or by the Company, in its discretion, if such determination is expressly allocated to the Company herein, subject to the following:

(i) Except as otherwise determined by the Committee, if, on such date, the Stock is listed on a national or regional securities exchange or market system, the Fair Market Value of a share of Stock shall be the closing price of a share of Stock as quoted on the New York Stock Exchange or such other national or regional securities exchange or market system constituting the primary market for the Stock, as reported in *The Wall Street Journal* or such other source as the Company deems reliable. If the relevant date does not fall on a day on which the Stock has traded on such securities exchange or market system, the date on which the Fair Market Value shall be established shall be the last day on which the Stock was so traded prior to the relevant date, or such other appropriate day as shall be determined by the Committee, in its discretion.

(ii) Notwithstanding the foregoing, the Committee may, in its discretion, determine the Fair Market Value on the basis of the opening, closing, high, low or average sale price of a share of Stock or the actual sale price of a share of Stock received by a Participant, on such date, the preceding trading day, the next succeeding trading day or an average determined over a period of trading days. The Committee may vary its method of determination of the Fair Market Value as provided in this Section for different purposes under the Plan.

(iii) If, on such date, the Stock is not listed on a national or regional securities exchange or market system, the Fair Market Value of a share of Stock shall be as determined by the Committee in good faith without regard to any restriction other than a restriction which, by its terms, will never lapse.

(q) *" **Incentive Stock Option** "* means an Option intended to be (as set forth in the Award Agreement) and which qualifies as an incentive stock option within the meaning of Section 422(b) of the Code.

(r) *" **Insider** "* means an Officer, a Director or any other person whose transactions in Stock are subject to Section 16 of the Exchange Act.

(s) ***"Mandatory Retirement"*** means retirement as a Director at age 70 or at such other age as may be specified in the retirement policy for the Board in effect at the time of a Nonemployee Director's termination of Service as a Director.

(t) ***"Net-Exercise"*** means a procedure by which the Participant will be issued a number of shares of Stock determined in accordance with the following formula:

X = Y(A-B)/A, where
X = the number of shares of Stock to be issued to the Participant upon exercise of the Option;
Y = the total number of shares with respect to which the Participant has elected to exercise the Option;
A = the Fair Market Value of one (1) share of Stock;
B = the exercise price per share (as defined in the Participant's Award Agreement).

(u) " ***Nonemployee Director*** " means a Director who is not an Employee.

(v) " ***Nonemployee Director Award*** " means an Award granted to a Nonemployee Director pursuant to Section 7 of the Plan.

(w) " ***Nonstatutory Stock Option*** " means an Option not intended to be (as set forth in the Award Agreement) an incentive stock option within the meaning of Section 422(b) of the Code.

(x) " ***Officer*** " means any person designated by the Board as an officer of the Company.

(y) " ***Option*** " means the right to purchase Stock at a stated price for a specified period of time granted to a Participant pursuant to Section 6 or Section 7 of the Plan. An Option may be either an Incentive Stock Option or a Nonstatutory Stock Option.

(z) ***"Option Expiration Date"*** means the date of expiration of the Option's term as set forth in the Award Agreement.

(aa) " ***Parent Corporation*** " means any present or future "parent corporation" of the Company, as defined in Section 424(e) of the Code.

(bb) " ***Participant*** " means any eligible person who has been granted one or more Awards.

(cc) " ***Participating Company*** " means the Company or any Parent Corporation, Subsidiary Corporation or Affiliate.

(dd) " ***Participating Company Group*** " means, at any point in time, all entities collectively which are then Participating Companies.

(ee) " ***Performance Award*** " means an Award of Performance Shares or Performance Units.

(ff) " ***Performance Award Formula*** " means, for any Performance Award, a formula or table established by the Committee pursuant to Section 10.3 of the Plan which provides the basis for computing the value of a Performance Award at one or more threshold levels of attainment of the applicable Performance Goal(s) measured as of the end of the applicable Performance Period.

(gg) " ***Performance Goal*** " means a performance goal established by the Committee pursuant to Section 10.3 of the Plan.

(hh) " ***Performance Period*** " means a period established by the Committee pursuant to Section 10.3 of the Plan at the end of which one or more Performance Goals are to be measured.

(jj) *" **Performance Share** "* means a bookkeeping entry representing a right granted to a Participant pursuant to Section 10 of the Plan to receive a payment equal to the value of a Performance Share, as determined by the Committee, based on performance.

(jj) *" **Performance Unit** "* means a bookkeeping entry representing a right granted to a Participant pursuant to Section 10 of the Plan to receive a payment equal to the value of a Performance Unit, as determined by the Committee, based upon performance.

(kk) *" **Restricted Stock Award** "* means an Award of Restricted Stock.

(ll) *" **Restricted Stock Unit"*** or *" **Stock Unit** "* means a bookkeeping entry representing a right granted to a Participant pursuant to Section 11 or Section 12 of the Plan, respectively, to receive a share of Stock on a date determined in accordance with the provisions of Section 11 or Section 12 , as applicable, and the Participant's Award Agreement.

(mm) *" **Restriction Period** "* means the period established in accordance with Section 9.4 of the Plan during which shares subject to a Restricted Stock Award are subject to Vesting Conditions.

(nn) ***"Retirement"*** means termination as an Employee of a Participating Company at age 55 or older, provided that the Participant was an Employee for at least five consecutive years prior to the date of such termination.

(oo) *" **Rule 16b-3** "* means Rule 16b-3 under the Exchange Act, as amended from time to time, or any successor rule or regulation.

(pp) *" **SAR** "* or *" **Stock Appreciation Right** "* means a bookkeeping entry representing, for each share of Stock subject to such SAR, a right granted to a Participant pursuant to Section 8 of the Plan to receive payment in any combination of shares of Stock or cash of an amount equal to the excess, if any, of the Fair Market Value of a share of Stock on the date of exercise of the SAR over the exercise price.

(qq) *" **Section 162(m)** "* means Section 162(m) of the Code.

(rr) *" **Securities Act** "* means the Securities Act of 1933, as amended.

(ss) *" **Service** "* means a Participant's employment or service with the Participating Company Group, whether in the capacity of an Employee, a Director or a Consultant. A Participant's Service shall not be deemed to have terminated merely because of a change in the capacity in which the Participant renders such Service or a change in the Participating Company for which the Participant renders such Service, provided that there is no interruption or termination of the Participant's Service. Furthermore, a Participant's Service shall not be deemed to have terminated if the Participant takes any military leave, sick leave, or other bona fide leave of absence approved by the Company. However, if any such leave taken by a Participant exceeds ninety (90) days, then on the one hundred eighty-first (181st) day following the commencement of such leave any Incentive Stock Option held by the Participant shall cease to be treated as an Incentive Stock Option and instead shall be treated thereafter as a Nonstatutory Stock Option, unless the Participant's right to return to Service with the

Participating Company Group is guaranteed by statute or contract. Notwithstanding the foregoing, unless otherwise designated by the Company or required by law, a leave of absence shall not be treated as Service for purposes of determining vesting under the Participant's Award Agreement. A Participant's Service shall be deemed to have terminated either upon an actual termination of Service or upon the entity for which the Participant performs Service ceasing to be a Participating Company. Subject to the foregoing, the Company, in its discretion, shall determine whether the Participant's Service has terminated and the effective date of such termination.

(tt) ***Stock*** " means the common stock of the Company, as adjusted from time to time in accordance with Section 4.2 of the Plan.

(uu) " ***Stock-Based Awards*** " means any award that is valued in whole or in part by reference to, or is otherwise based on, the Stock, including dividends on the Stock, but not limited to those Awards described in Sections 6 through 12 of the Plan.

(vv) " ***Subsidiary Corporation*** " means any present or future "subsidiary corporation" of the Company, as defined in Section 424(f) of the Code.

(ww) " ***Ten Percent Owner*** " means a Participant who, at the time an Option is granted to the Participant, owns stock possessing more than ten percent (10%) of the total combined voting power of all classes of stock of a Participating Company (other than an Affiliate) within the meaning of Section 422(b)(6) of the Code.

(xx) " ***Vesting Conditions*** " mean those conditions established in accordance with Section 9.4 or Section 11.2 of the Plan prior to the satisfaction of which shares subject to a Restricted Stock Award or Restricted Stock Unit Award, respectively, remain subject to forfeiture or a repurchase option in favor of the Company upon the Participant's termination of Service.

2.2 **Construction.** Captions and titles contained herein are for convenience only and shall not affect the meaning or interpretation of any provision of the Plan. Except when otherwise indicated by the context, the singular shall include the plural and the plural shall include the singular. Use of the term "or" is not intended to be exclusive, unless the context clearly requires otherwise.

3. Administration .

3.1 **Administration by the Committee.** The Plan shall be administered by the Committee. All questions of interpretation of the Plan or of any Award shall be determined by the Committee, and such determinations shall be final and binding upon all persons having an interest in the Plan or such Award.

3.2 **Authority of Officers.** Any Officer shall have the authority to act on behalf of the Company with respect to any matter, right, obligation, determination or election which is the responsibility of or which is allocated to the Company herein, provided the Officer has apparent authority with respect to such matter, right, obligation, determination or election. In addition, to the extent specified in a resolution adopted by the Board, the Chief Executive Officer of the

Company shall have the authority to grant Awards to an Employee who is not an Insider and who is receiving a salary below the level which requires approval by the Committee; provided that the terms of such Awards conform to guidelines established by the Committee and provided further that at the time of making such Awards the Chief Executive Officer also is a Director.

3.3 **Administration with Respect to Insiders.** With respect to participation by Insiders in the Plan, at any time that any class of equity security of the Company is registered pursuant to Section 12 of the Exchange Act, the Plan shall be administered in compliance with the requirements, if any, of Rule 16b-3.

3.4 **Committee Complying with Section 162(m).** While the Company is a "publicly held corporation" within the meaning of Section 162(m), the Board may establish a Committee of "outside directors" within the meaning of Section 162(m) to approve the grant of any Award which might reasonably be anticipated to result in the payment of employee remuneration that would otherwise exceed the limit on employee remuneration deductible for income tax purposes pursuant to Section 162(m).

3.5 **Powers of the Committee .** In addition to any other powers set forth in the Plan and subject to the provisions of the Plan, the Committee shall have the full and final power and authority, in its discretion:

(a) to determine the persons to whom, and the time or times at which, Awards shall be granted and the number of shares of Stock or units to be subject to each Award based on the recommendation of the Chief Executive Officer of the Company (except that Awards to the Chief Executive Officer shall be based on the recommendation of the independent members of the Board in compliance with applicable stock exchange rules and Awards to Nonemployee Directors shall be granted automatically pursuant to Section 7 of the Plan);

(b) to determine the type of Award granted and to designate Options as Incentive Stock Options or Nonstatutory Stock Options;

(c) to determine the Fair Market Value of shares of Stock or other property;

(d) to determine the terms, conditions and restrictions applicable to each Award (which need not be identical) and any shares acquired pursuant thereto, including, without limitation, (i) the exercise or purchase price of shares purchased pursuant to any Award, (ii) the method of payment for shares purchased pursuant to any Award, (iii) the method for satisfaction of any tax withholding obligation arising in connection with Award, including by the withholding or delivery of shares of Stock, (iv) the timing, terms and conditions of the exercisability or vesting of any Award or any shares acquired pursuant thereto, (v) the Performance Award Formula and Performance Goals applicable to any Award and the extent to which such Performance Goals have been attained, (vi) the time of the expiration of any Award, (vii) the effect of the Participant's termination of Service on any of the foregoing, and (viii) all other terms, conditions and restrictions applicable to any Award or shares acquired pursuant thereto not inconsistent with the terms of the Plan;

(e) to determine whether an Award will be settled in shares of Stock, cash, or in any combination thereof;

(f) to approve one or more forms of Award Agreement;

(g) to amend, modify, extend, cancel or renew any Award or to waive any restrictions or conditions applicable to any Award or any shares acquired pursuant thereto;

(h) to accelerate, continue, extend or defer the exercisability or vesting of any Award or any shares acquired pursuant thereto, including with respect to the period following a Participant's termination of Service;

(i) without the consent of the affected Participant and notwithstanding the provisions of any Award Agreement to the contrary, to unilaterally substitute at any time a Stock Appreciation Right providing for settlement solely in shares of Stock in place of any outstanding Option, provided that such Stock Appreciation Right covers the same number of shares of Stock and provides for the same exercise price (subject in each case to adjustment in accordance with Section 4.2) as the replaced Option and otherwise provides substantially equivalent terms and conditions as the replaced Option, as determined by the Committee;

(j) to prescribe, amend or rescind rules, guidelines and policies relating to the Plan, or to adopt sub-plans or supplements to, or alternative versions of, the Plan, including, without limitation, as the Committee deems necessary or desirable to comply with the laws or regulations of or to accommodate the tax policy, accounting principles or custom of, foreign jurisdictions whose citizens may be granted Awards;

(k) to correct any defect, supply any omission or reconcile any inconsistency in the Plan or any Award Agreement and to make all other determinations and take such other actions with respect to the Plan or any Award as the Committee may deem advisable to the extent not inconsistent with the provisions of the Plan or applicable law; and

(l) to delegate to the Chief Executive Officer or the Senior Vice President of Human Resources the authority with respect to ministerial matters regarding the Plan and Awards made under the Plan.

3.6 **Option or SAR Repricing.** Without the affirmative vote of holders of a majority of the shares of Stock cast in person or by proxy at a meeting of the shareholders of the Company at which a quorum representing a majority of all outstanding shares of Stock is present or represented by proxy, the Board shall not approve a program providing for either (a) the cancellation of outstanding Options or SARs and the grant in substitution therefore of new Options or SARs having a lower exercise price or (b) the amendment of outstanding Options or SARs to reduce the exercise price thereof. This paragraph shall not be construed to apply to "issuing or assuming a stock option in a transaction to which section 424(a) applies," within the meaning of Section 424 of the Code.

3.7 **Indemnification.** In addition to such other rights of indemnification as they may have as members of the Board or the Committee or as officers or employees of the Participating Company Group, members of the Board or the Committee and any officers or employees of the Participating Company Group to whom authority to act for the Board, the Committee or the Company is delegated shall be indemnified by the Company against all reasonable expenses, including attorneys' fees, actually and necessarily incurred in connection with the defense of any

action, suit or proceeding, or in connection with any appeal therein, to which they or any of them may be a party by reason of any action taken or failure to act under or in connection with the Plan, or any right granted hereunder, and against all amounts paid by them in settlement thereof (provided such settlement is approved by independent legal counsel selected by the Company) or paid by them in satisfaction of a judgment in any such action, suit or proceeding, except in relation to matters as to which it shall be adjudged in such action, suit or proceeding that such person is liable for gross negligence, bad faith or intentional misconduct in duties; provided, however, that within sixty (60) days after the institution of such action, suit or proceeding, such person shall offer to the Company, in writing, the opportunity at its own expense to handle and defend the same.

4. **Shares Subject to Plan .**

4.1 **Maximum Number of Shares Issuable.** Subject to adjustment as provided in Section 4.2, the maximum aggregate number of shares of Stock that may be issued under the Plan shall be twelve million (12,000,000) and shall consist of authorized but unissued or reacquired shares of Stock or any combination thereof. If an outstanding Award for any reason expires or is terminated or canceled without having been exercised or settled in full, or if shares of Stock acquired pursuant to an Award subject to forfeiture or repurchase are forfeited or repurchased by the Company, the shares of Stock allocable to the terminated portion of such Award or such forfeited or repurchased shares of Stock shall again be available for issuance under the Plan. Shares of Stock shall not be deemed to have been issued pursuant to the Plan (a) with respect to any portion of an Award that is settled in cash or (b) to the extent such shares are withheld or reacquired by the Company in satisfaction of tax withholding obligations pursuant to Section 16.2 . Upon payment in shares of Stock pursuant to the exercise of an SAR, the number of shares available for issuance under the Plan shall be reduced only by the number of shares actually issued in such payment. If the exercise price of an Option is paid by tender to the Company, or attestation to the ownership, of shares of Stock owned by the Participant, or by means of a Net-Exercise, the number of shares available for issuance under the Plan shall be reduced only by the net number of shares for which the Option is exercised.

4.2 **Adjustments for Changes in Capital Structure .** Subject to any required action by the shareholders of the Company, in the event of any change in the Stock effected without receipt of consideration by the Company, whether through merger, consolidation, reorganization, reincorporation, recapitalization, reclassification, stock dividend, stock split, reverse stock split, split-up, split-off, spin-off, combination of shares, exchange of shares, or similar change in the capital structure of the Company, or in the event of payment of a dividend or distribution to the shareholders of the Company in a form other than Stock (excepting normal cash dividends) that has a material effect on the Fair Market Value of shares of Stock, appropriate adjustments shall be made in the number and kind of shares subject to the Plan and to any outstanding Awards, in the Award limits set forth in Section 5.4 , in the Nonemployee Director Awards to be granted automatically pursuant to Section 7, and in the exercise or purchase price per share under any outstanding Award in order to prevent dilution or enlargement of Participants' rights under the Plan. For purposes of the foregoing, conversion of any convertible securities of the Company shall not be treated as "effected without receipt of consideration by the Company." Any fractional share resulting from an adjustment pursuant to this Section 4.2 shall be rounded down to the nearest whole number. The Committee in its sole discretion, may also make such

adjustments in the terms of any Award to reflect, or related to, such changes in the capital structure of the Company or distributions as it deems appropriate, including modification of Performance Goals, Performance Award Formulas and Performance Periods. The adjustments determined by the Committee pursuant to this Section 4.2 shall be final, binding and conclusive.

5. **Eligibility and Award Limitations .**

5.1 **Persons Eligible for Awards.** Awards may be granted only to Employees, Consultants and Directors. For purposes of the foregoing sentence, "Employees," "Consultants"and "Directors" shall include prospective Employees, prospective Consultants and prospective Directors to whom Awards are granted in connection with written offers of an employment or other service relationship with the Participating Company Group; provided, however, that no Stock subject to any such Award shall vest, become exercisable or be issued prior to the date on which such person commences Service. A Nonemployee Director Award may be granted only to a person who, at the time of grant, is a Nonemployee Director.

5.2 **Participation.** Awards other than Nonemployee Director Awards are granted solely at the discretion of the Committee. Eligible persons may be granted more than one Award. However , excepting Nonemployee Director Awards, eligibility in accordance with this Section shall not entitle any person to be granted an Award, or, having been granted an Award, to be granted an additional Award.

5.3 **Incentive Stock Option Limitations.**

(a) ***Persons Eligible.*** An Incentive Stock Option may be granted only to a person who, on the effective date of grant, is an Employee of the Company, a Parent Corporation or a Subsidiary Corporation (each being an " ***ISO-Qualifying Corporation*** "). Any person who is not an Employee of an ISO-Qualifying Corporation on the effective date of the grant of an Option to such person may be granted only a Nonstatutory Stock Option. An Incentive Stock Option granted to a prospective Employee upon the condition that such person become an Employee of an ISO-Qualifying Corporation shall be deemed granted effective on the date such person commences Service with an ISO-Qualifying Corporation, with an exercise price determined as of such date in accordance with Section 6.1 .

(b) ***Fair Market Value Limitation.*** To the extent that options designated as Incentive Stock Options (granted under all stock option plans of the Participating Company Group, including the Plan) become exercisable by a Participant for the first time during any calendar year for stock having a Fair Market Value greater than One Hundred Thousand Dollars ($100,000), the portion of such options which exceeds such amount shall be treated as Nonstatutory Stock Options. For purposes of this Section, options designated as Incentive Stock Options shall be taken into account in the order in which they were granted, and the Fair Market Value of stock shall be determined as of the time the option with respect to such stock is granted. If the Code is amended to provide for a limitation different from that set forth in this Section, such different limitation shall be deemed incorporated herein effective as of the date and with respect to such Options as required or permitted by such amendment to the Code. If an Option is treated as an Incentive Stock Option in part and as a Nonstatutory Stock Option in part by reason of the limitation set forth in this Section, the Participant may designate which portion of such

Option the Participant is exercising. In the absence of such designation, the Participant shall be deemed to have exercised the Incentive Stock Option portion of the Option first. Upon exercise, shares issued pursuant to each such portion shall be separately identified.

5.4 **Award Limits.**

(a) ***Maximum Number of Shares Issuable Pursuant to Incentive Stock Options.*** Subject to adjustment as provided in Section 4.2 , the maximum aggregate number of shares of Stock that may be issued under the Plan pursuant to the exercise of Incentive Stock Options shall not exceed twelve million (12,000,000) shares. The maximum aggregate number of shares of Stock that may be issued under the Plan pursuant to all Awards other than Incentive Stock Options shall be the number of shares determined in accordance with Section 4.1 , subject to adjustment as provided in Section 4.2 and further subject to the limitation set forth in Section 5.4(b) below.

(b) ***Aggregate Limit on Full Value Awards.*** Subject to adjustment as provided in Section 4.2 , in no event shall more than twelve million (12,000,000) shares in the aggregate be issued under the Plan pursuant to the exercise or settlement of Restricted Stock Awards, Restricted Stock Unit Awards and Performance Awards ("Full Value Awards"). Except with respect to a maximum of five percent (5%) of the shares of Stock authorized in this Section 5.4(b), any Full Value Awards which vest on the basis of the Participant's continued Service shall not provide for vesting which is any more rapid than annual pro rata vesting over a three (3) year period a nd any Full Value Awards which vest upon the attainment of Performance Goals shall provide for a Performance Period of at least twelve (12) months.

(c) ***Section 162(m) Award Limits.*** The following limits shall apply to the grant of any Award if, at the time of grant, the Company is a "publicly held corporation" within the meaning of Section 162(m).

(i) **Options and SARs.** Subject to adjustment as provided in Section 4.2 , no Employee shall be granted within any fiscal year of the Company one or more Options or Freestanding SARs which in the aggregate are for more than 400,000 shares of Stock reserved for issuance under the Plan.

(ii) **Restricted Stock and Restricted Stock Unit Awards.** Subject to adjustment as provided in Section 4.2 , no Employee shall be granted within any fiscal year of the Company one or more Restricted Stock Awards or Restricted Stock Unit Awards, subject to Vesting Conditions based on the attainment of Performance Goals, for more than 400,000 shares of Stock reserved for issuance under the Plan.

(iii) **Performance Awards.** Subject to adjustment as provided in Section 4.2 , no Employee shall be granted (1) Performance Shares which could result in such Employee receiving more than 400,000 shares of Stock reserved for issuance under the Plan for each full fiscal year of the Company contained in the Performance Period for such Award, or (2) Performance Units which could result in such Employee receiving more than two million dollars ($2 million) for each full fiscal year of the Company contained in the Performance Period

for such Award. No Participant may be granted more than one Performance Award for the same Performance Period.

6. **Terms and Conditions of Options .**

Options shall be evidenced by Award Agreements specifying the number of shares of Stock covered thereby, in such form as the Committee shall from time to time establish. No Option or purported Option shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing Options may incorporate all or any of the terms of the Plan by reference and , except as otherwise set forth in Section 7 with respect to Nonemployee Director Options, shall comply with and be subject to the following terms and conditions:

6.1 **Exercise Price .** The exercise price for each Option shall be established in the discretion of the Committee; provided, however, that (a) the exercise price per share shall be not less than the Fair Market Value of a share of Stock on the effective date of grant of the Option and (b) no Incentive Stock Option granted to a Ten Percent Owner shall have an exercise price per share less than one hundred ten percent (110%) of the Fair Market Value of a share of Stock on the effective date of grant of the Option. Notwithstanding the foregoing, an Option (whether an Incentive Stock Option or a Nonstatutory Stock Option) may be granted with an exercise price lower than the minimum exercise price set forth above if such Option is granted pursuant to an assumption or substitution for another option in a manner qualifying under the provisions of Section 424(a) of the Code.

6.2 **Exercisability and Term of Options .** Options shall be exercisable at such time or times, or upon such event or events, and subject to such terms, conditions, performance criteria and restrictions as shall be determined by the Committee and set forth in the Award Agreement evidencing such Option; provided, however, that (a) no Option shall be exercisable after the expiration of ten (10) years after the effective date of grant of such Option, (b) no Incentive Stock Option granted to a Ten Percent Owner shall be exercisable after the expiration of five (5) years after the effective date of grant of such Option, and (c) no Option granted to a prospective Employee, prospective Consultant or prospective Director may become exercisable prior to the date on which such person commences Service. Subject to the foregoing, unless otherwise specified by the Committee in the grant of an Option, any Option granted hereunder shall terminate ten (10) years after the effective date of grant of the Option, unless earlier terminated in accordance with its provisions.

6.3 **Payment of Exercise Price.**

(a) ***Forms of Consideration Authorized.*** Except as otherwise provided below, payment of the exercise price for the number of shares of Stock being purchased pursuant to any Option shall be made (i) in cash, by check or in cash equivalent, (ii) by tender to the Company, or attestation to the ownership, of shares of Stock owned by the Participant having a ,Fair Market Value not less than the exercise price, (iii) by delivery of a properly executed notice of exercise together with irrevocable instructions to a broker providing for the assignment to the Company of the proceeds of a sale or loan with respect to some or all of the shares being acquired upon the exercise of the Option (including, without limitation, through an exercise

complying with the provisions of Regulation T as promulgated from time to time by the Board of Governors of the Federal Reserve System) (a " ***Cashless Exercise*** "), (iv) by delivery of a properly executed notice of exercise electing a Net-Exercise, (v) by such other consideration as may be approved by the Committee from time to time to the extent permitted by applicable law, or (vi) by any combination thereof. The Committee may at any time or from time to time grant Options which do not permit all of the foregoing forms of consideration to be used in payment of the exercise price or which otherwise restrict one or more forms of consideration.

(b) ***Limitations on Forms of Consideration.***

(i) **Tender of Stock.** Notwithstanding the foregoing, an Option may not be exercised by tender to the Company, or attestation to the ownership, of shares of Stock to the extent such tender or attestation would constitute a violation of the provisions of any law, regulation or agreement restricting the redemption of the Company's stock.

(ii) **Cashless Exercise.** The Company reserves, at any and all times, the right, in the Company's sole and absolute discretion, to establish, decline to approve or terminate any program or procedures for the exercise of Options by means of a Cashless Exercise, including with respect to one or more Participants specified by the Company notwithstanding that such program or procedures may be available to other Participants.

6.4 **Effect of Termination of Service.**

(a) ***Option Exercisability .*** Subject to earlier termination of the Option as otherwise provided herein and unless otherwise provided by the Committee, an Option shall be exercisable after a Participant's termination of Service only during the applicable time periods provided in the Award Agreement.

(b) ***Extension if Exercise Prevented by Law .*** Notwithstanding the foregoing, unless the Committee provides otherwise in the Award Agreement, if the exercise of an Option within the applicable time periods is prevented by the provisions of Section 14.1 below, the Option shall remain exercisable until three (3) months (or such longer period of time as determined by the Committee, in its discretion) after the date the Participant is notified by the Company that the Option is exercisable, but in any event no later than the Option Expiration Date.

(c) ***Extension if Participant Subject to Section 16(b*).** Notwithstanding the foregoing, if a sale within the applicable time periods of shares acquired upon the exercise of the Option would subject the Participant to suit under Section 16(b) of the Exchange Act, the Option shall remain exercisable until the earliest to occur of (i) the tenth (10th) day following the date on which a sale of such shares by the Participant would no longer be subject to such suit, (ii) the one hundred and ninetieth (190th) day after the Participant's termination of Service, or (iii) the Option Expiration Date.

6.5 **Transferability of Options.** During the lifetime of the Participant, an Option shall be exercisable only by the Participant or the Participant's guardian or legal representative. Prior to the issuance of shares of Stock upon the exercise of an Option, the Option shall not be subject in any manner to anticipation, alienation, sale, exchange, transfer, assignment, pledge,

encumbrance, or garnishment by creditors of the Participant or the Participant's beneficiary, except transfer by will or by the laws of descent and distribution. Notwithstanding the foregoing, to the extent permitted by the Committee, in its discretion, and set forth in the Award Agreement evidencing such Option, a Nonstatutory Stock Option shall be assignable or transferable subject to the applicable limitations, if any, described in the General Instructions to Form S-8 Registration Statement under the Securities Act.

7. **Terms and Conditions of Nonemployee Director Awards .**

Nonemployee Director Awards shall be evidenced by Award Agreements in such form as the Board shall from time to time establish. Such Award Agreements may incorporate all or any of the terms of the Plan by reference, shall be automatic and non-discretionary and shall comply with and be subject to the following terms and conditions:

7.1 **Automatic Grant of Restricted Stock.**

(a) ***Timing and Amount of Grant.*** On the first business day of each calendar year beginning on January 1, 2006, and continuing for the term of the Plan, each person who is a Nonemployee Director on such date shall be granted a Restricted Stock Award to purchase a number of shares of Stock determined by dividing thirty thousand dollars ($30,000) (or $40,000 for grants made on or after January, 1, 2007) by the Fair Market Value of the Stock on the first business day of the applicable calendar year, and rounding down to the nearest whole number.

(b) ***Vesting*** The shares subject to the Restricted Stock Award granted pursuant to Section 7.1(a) shall vest in equal annual installments of twenty percent (20%) on each anniversary of the date of grant, with one hundred percent (100%) of the shares vested on the fifth anniversary of the date of grant.

7.2 **Annual Election to Receive Nonstatutory Stock Option and Restricted Stock Units.** On a date no later than December 31 of each calendar year during the term of the Plan, each person who is then a Nonemployee Director shall deliver to the Board a written election to receive either Nonstatutory Stock Options or Restricted Stock Units, or both, with an aggregate value of $30,000 (or $40,000 for grants made on or after January, 1, 2007), on the first business day of the following calendar year, provided the person continues to be a Nonemployee Director on the date of grant. A Nonemployee Director may allocate between Nonstatutory Stock Options and Restricted Stock Units in minimum increments with a value equal to $5,000, as determined in accordance with Sections 7.3 and 7.4. All awards of Nonstatutory Stock Options and Restricted Stock Units made to Nonemployee Directors shall comply with the provisions of Sections 7.3 and 7.4, respectively. A Nonemployee Director who fails to make a timely election or who first becomes a Nonemployee Director after December 31 shall be awarded Nonstatutory Stock Options and Restricted Stock Units each with a value of $15,000 (or $20,000 for grants made on or after January, 1, 2007), as determined in accordance with Sections 7.3 and 7.4, provided the Nonemployee Director continues to be a Nonemployee Director on the first business day of the following calendar year.

7.3 **Grant of Nonstatutory Stock Option.**

(a) ***Timing and Amount of Grant*** . Unless a Nonemployee Director made an election to decline the award of a Nonstatutory Stock Option in accordance with Section 7.2 above, on the first business day of each calendar year beginning on January 1, 2006, and continuing for the term of the Plan, each person who is a Nonemployee Director on such date shall receive a grant of a Nonstatutory Stock Option with an aggregate value equal to $5,000, $10,000, $15,000, $20,000, $25,000 or $30,000 (grants made after January 1, 2007 also may have an aggregate value of $35,000 or $40,000) as previously elected by the Nonemployee Director (or $15,000 (or $20,000 for grants made on or after January, 1, 2007) in the case of a Nonemployee Director who failed to make a timely election or who became a Nonemployee Director after December 31) (the ***"Elected Option Value"***). The number of shares subject to the Nonstatutory Stock Option shall be determined by dividing the Elected Option Value by the value of a Nonstatutory Stock Option to purchase a single share of Stock as of the first business day of the applicable calendar year. The per share option value shall be calculated in accordance with the Black-Scholes stock option valuation method using the average preceding November closing price of Stock and reducing the per option value by twenty percent (20%). The resulting number of shares subject to the Nonstatutory Stock Option shall be rounded down to the nearest whole share. No person shall receive more than one grant of Nonstatutory Stock Options pursuant to this Section 7.3(a) during any calendar year.

(b) ***Exercise Price and Payment*** . The exercise price of each Nonstatutory Stock Option granted pursuant to Section 7.3(a) shall be the Fair Market Value of the Stock on the date of grant. The payment of the exercise price for the number of share of Stock being purchased pursuant to the Nonstatutory Stock Option shall be made in accordance with the provisions of Section 6.3.

(c) ***Vesting and Exercisability*** . The Nonstatutory Stock Option granted in accordance with this Section shall become vested and exercisable as to one third (1/3) of the shares subject to the Nonstatutory Stock Option on the second, third and fourth anniversaries of the date of grant, respectively. The Nonstatutory Stock Option shall terminate ten (10) years after the date of grant, unless earlier terminated in accordance with its provisions.

7.4 **Grant of Restricted Stock Unit.**

(a) ***Timing and Amount of Grant*** . Unless a Nonemployee Director made an election to decline the award of a Restricted Stock Unit in accordance with Section 7.2 above, on the first business day of each calendar year beginning on January 1, 2006, and continuing for the term of the Plan, each person who is a Nonemployee Director on such date shall receive a grant of a Restricted Stock Unit Award with an aggregate value (as determined by the Fair Market Value of the Stock on the first business day of the applicable calendar year) equal to $5,000, $10,000, $15,000, $20,000, $25,000 or $30,000, (grants made after January 1, 2007 also may have an aggregate value of $35,000 or $40,000) as previously elected by the Nonemployee Director (or $15,000 (or $20,000 for grants made on or after January, 1, 2007) in the case of a Nonemployee Director who failed to make a timely election or who became a Nonemployee Director after December 31) (the ***"Elected Stock Unit Value"***). The number of shares subject to the Restricted Stock Unit Award shall be determined by dividing the Elected Stock Unit Value by the Fair Market Value of the Stock as of the first business day of the applicable calendar year (including fractions computed to three decimal places). The Restricted Stock Units awarded to a

Nonemployee Director shall be credited to a newly established Restricted Stock Unit account. Each Restricted Stock Unit awarded to a Nonemployee Director in accordance with this Section 7.4(a) shall be deemed to be equal to one (1) (or fraction thereof) share of Stock on the date of grant, and shall thereafter fluctuate in value in accordance with the Fair Market Value of the Stock. No person shall receive more than one grant of Restricted Stock Units pursuant to this Section 7.4(a) during any calendar year.

(b) ***Dividend Rights*** . Each Nonemployee Director's Restricted Stock Unit account shall be credited quarterly on each dividend payment date with additional shares of Restricted Stock Units (including fractions computed to three decimal places) determined by dividing (1) the amount of cash dividends paid on such date with respect to the number of shares of Stock represented by the Restricted Stock Units previously credited to the account by (2) the Fair Market Value per share of Stock on such date. Such additional Restricted Stock Units shall be subject to the same terms and conditions and shall be settled in the same manner and at the same time as the Restricted Stock Units originally subject to the Restricted Stock Unit Award.

(c) ***Settlement of Restricted Stock Unit Award*** . Settlement of the shares credited to a Nonemployee Director's Restricted Stock Unit account shall only be made after the Nonemployee Director's Retirement or Mandatory Retirement from the Board or as provided in Section 7.5 below. Settlement shall be made only in the form of shares of Stock equal to the number of Restricted Stock Units credited to the Nonemployee Director's account on the date of distribution, rounded down to the nearest whole share. The Nonemployee Director may elect to receive the Stock in a lump sum distribution or in a series of ten or less approximately equal annual installments, provided that distribution shall commence no later than January of the year following the year in which the Nonemployee Director's Retirement or Mandatory Retirement occurred.

7.5 **Effect of Termination of Service as a Nonemployee Director.**

(a) ***Status of Award .*** Subject to earlier termination of the Nonemployee Director Award as otherwise provided herein, the status of a Nonemployee Director Award shall be determined as follows:

(i) **Death or Disability.** If the Nonemployee Director's Service terminates due to death or Disability (1) all shares subject to the Restricted Stock Award shall become fully vested, and the Participant (or the Participant's legal representative or other person who acquired the rights to the Restricted Stock by reason of the Participant's death) shall have the right to resell or transfer such shares at any time; (2) all Nonstatutory Stock Options held by the Participant shall become fully vested and exercisable, and the Participant (or the Participant's legal representative or other person who acquired the rights to the Nonstatutory Stock Option by reason of the Participant's death) shall have the right to exercise the Nonstatutory Stock Options until the earlier of (a) the date that is twelve (12) months after the date on which the Participant's Service terminated, or (b) the Option Expiration Date and (3) all Restricted Stock Units credited to the Nonemployee Director's account shall immediately become payable to the Participant (or the Participant's legal representative or other person who acquired the rights to the Restricted Stock Units by reason of the Participant's death) in the form of a number of shares of Stock

equal to the number of Restricted Stock Units credited to the Restricted Stock Unit account, rounded down to the nearest whole share.

(ii) **Mandatory Retirement** . If the Participant's Service terminates because of the Mandatory Retirement of the Participant (1) all shares subject to the Restricted Stock Award shall become fully vested, and the Participant shall have the right to resell or transfer such shares at any time; (2) all Nonstatutory Stock Options held by the Participant shall become fully vested and exercisable and the Participant shall have the right to exercise the Nonstatutory Stock Options until the earlier of (a) the date that is five (5) years after the date on which the Participant's Service terminated, or (b) the Option Expiration Date and (3) all Restricted Stock Units credited to the Nonemployee Director's account shall immediately become payable to the Participant in accordance with Section 7.4(c) above.

(iii) **her Termination of Service.** If the Participant's Service terminates for any reason other than those enumerated in Sections 7.5(a)(i) and 7.5(a)(ii), (1) any unvested shares of Restricted Stock shall be forfeited to the Company and from and after the date of such termination, the Participant shall cease to be a shareholder with respect to such forfeited shares and shall have no dividend, voting or other rights with respect thereto, (2) the unvested portion of any Nonstatutory Stock Option shall terminate, and any portion of the Nonstatutory Stock Option exercisable by the Participant on the date on which the Participant's Service terminated may be exercised until the earlier of (a) the date that is three (3) months after the date on which the Participant's Service terminated, or (b) the Option Expiration Date and (3) except as provided in Section 7.4(c), all Restricted Stock Units credited to the Participant's account shall be forfeited on the date of termination.

(iv) Notwithstanding the provisions of Section 7.5(i) through 7.5(iii) above, the Board, in its sole discretion, may establish different terms and conditions pertaining to Nonemployee Director Awards.

(b) ***Extension if Exercise Prevented by Law .*** Notwithstanding the foregoing, if the exercise of a Nonstatutory Stock Option within the applicable time periods set forth in Section 7.5(a) is prevented by the provisions of Section 14.1 below, the Nonstatutory Stock Option shall remain exercisable until three (3) months after the date the Participant is notified by the Company that the Nonstatutory Stock Option is exercisable, but in any event no later than the Option Expiration Date.

(c) ***Extension if Participant Subject to Section 16(b*).** Notwithstanding the foregoing, if a sale within the applicable time periods set forth in Section 7.5(a) of shares acquired upon the exercise of the Nonstatutory Stock Option would subject the Participant to suit under Section 16(b) of the Exchange Act, the Nonstatutory Stock Option shall remain exercisable until the earliest to occur of (i) the tenth (10th) day following the date on which asale of such shares by the Participant would no longer be subject to such suit, (ii) the one hundred and ninetieth (190th) day after the Participant's termination of Service, or (iii) the Option Expiration Date.

7.6 **Effect of Change in Control on Nonemployee Director Awards.** Upon the occurrence of a Change in Control, (i) the vesting of all shares of Restricted Stock granted

pursuant to Section 7.1(a) shall be accelerated so that all such shares become fully vested, (ii) the vesting of Nonstatutory Stock Options granted pursuant to Section 7.3(a) shall be accelerated and such Nonstatutory Stock Options shall remain fully exercisable until the Option Expiration Date, and (iii) all Restricted Stock Units shall be settled in accordance with Section 7.4(c) as if the Change of Control constituted Retirement.

7.7 **Right to Decline Nonemployee Director Awards.** Notwithstanding the foregoing, any person may elect not to receive a Nonemployee Director Award by delivering written notice of such election to the Board no later than the day prior to the date such Nonemployee Director Award would otherwise be granted. A person so declining a Nonemployee Director Award shall receive no payment or other consideration in lieu of such declined Nonemployee Director Award. A person who has declined a Nonemployee Director Award may revoke such election by delivering written notice of such revocation to the Board no later than the day prior to the date such Nonemployee Director Award would be granted.

8. **Terms and Conditions of Stock Appreciation Rights .**

Stock Appreciation Rights shall be evidenced by Award Agreements specifying the number of shares of Stock subject to the Award, in such form as the Committee shall from time to time establish. No SAR or purported SAR shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing SARs may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions:

8.1 **Types of SARs Authorized.** SARs may be granted in tandem with all or any portion of a related Option (a " ***Tandem SAR*** ") or may be granted independently of any Option (a " ***Freestanding SAR*** "). A Tandem SAR may be granted either concurrently with the grant of the related Option or at any time thereafter prior to the complete exercise, termination, expiration or cancellation of such related Option.

8.2 **Exercise Price.** The exercise price for each SAR shall be established in the discretion of the Committee; provided, however, that (a) the exercise price per share subject to a Tandem SAR shall be the exercise price per share under the related Option and (b) the exercise price per share subject to a Freestanding SAR shall be not less than the Fair Market Value of a share of Stock on the effective date of grant of the SAR.

8.3 **Exercisability and Term of SARs.**

(a) ***Tandem SARs.*** Tandem SARs shall be exercisable only at the time and to the extent, and only to the extent, that the related Option is exercisable, subject to such provisions as the Committee may specify where the Tandem SAR is granted with respect to less than the full number of shares of Stock subject to the related Option.

(b) ***Freestanding SARs.*** Freestanding SARs shall be exercisable at such time or times, or upon such event or events, and subject to such terms, conditions, performance criteria and restrictions as shall be determined by the Committee and set forth in the Award Agreement evidencing such SAR; provided, however, that no Freestanding SAR shall be exercisable after the expiration of ten (10) years after the effective date of grant of such SAR.

8.4 **Deemed Exercise of SARs.** If, on the date on which an SAR would otherwise terminate or expire, the SAR by its terms remains exercisable immediately prior to such termination or expiration and, if so exercised, would result in a payment to the holder of such SAR, then any portion of such SAR which has not previously been exercised shall automatically be deemed to be exercised as of such date with respect to such portion.

8.5 **Effect of Termination of Service.** Subject to earlier termination of the SAR as otherwise provided herein and unless otherwise provided by the Committee in the grant of an SAR and set forth in the Award Agreement, an SAR shall be exercisable after a Participant's termination of Service only as provided in the Award Agreement.

8.6 **Nontransferability of SARs.** During the lifetime of the Participant, an SAR shall be exercisable only by the Participant or the Participant's guardian or legal representative. Prior to the exercise of an SAR, the SAR shall not be subject in any manner to anticipation, alienation, sale, exchange, transfer, assignment, pledge, encumbrance, or garnishment by creditors of the Participant or the Participant's beneficiary, except transfer by will or by the laws of descent and distribution.

9. **Terms and Conditions of Restricted Stock Awards .**

Restricted Stock Awards shall be evidenced by Award Agreements specifying the number of shares of Stock subject to the Award, in such form as the Committee shall from time to time establish. No Restricted Stock Award or purported Restricted Stock Award shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing Restricted Stock Awards may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions:

9.1 **Types of Restricted Stock Awards Authorized.** Restricted Stock Awards may or may not require the payment of cash compensation for the stock. Restricted Stock Awards may be granted upon such conditions as the Committee shall determine, including, without limitation, upon the attainment of one or more Performance Goals described in Section 10.4 . If either the grant of a Restricted Stock Award or the lapsing of the Restriction Period is to be contingent upon the attainment of one or more Performance Goals, the Committee shall follow procedures substantially equivalent to those set forth in Sections 10.3 through 10.5(a) .

9.2 **Purchase Price.** The purchase price, if any, for shares of Stock issuable under each Restricted Stock Award and the means of payment shall be established by the Committee in its discretion.

9.3 **Purchase Period.** A Restricted Stock Award requiring the payment of cash consideration shall be exercisable within a period established by the Committee; provided, however, that no Restricted Stock Award granted to a prospective Employee, prospective Consultant or prospective Director may become exercisable prior to the date on which such person commences Service.

9.4 **Vesting and Restrictions on Transfer.** Shares issued pursuant to any Restricted Stock Award may or may not be made subject to Vesting Conditions based upon the satisfaction

of such Service requirements, conditions, restrictions or performance criteria, including, without limitation, Performance Goals as described in Section 10.4 , as shall be established by the Committee and set forth in the Award Agreement evidencing such Award. During any Restriction Period in which shares acquired pursuant to a Restricted Stock Award remain subject to Vesting Conditions, such shares may not be sold, exchanged, transferred, pledged, assigned or otherwise disposed of other than as provided in the Award Agreement or as provided in Section 9.7 . Upon request by the Company, each Participant shall execute any agreement evidencing such transfer restrictions prior to the receipt of shares of Stock hereunder and shall promptly present to the Company any and all certificates representing shares of Stock acquired hereunder for the placement on such certificates of appropriate legends evidencing any such transfer restrictions.

9.5 **Voting Rights, Dividends and Distributions.** Except as provided in this Section, Section 9.4 and any Award Agreement, during the Restriction Period applicable to shares subject to a Restricted Stock Award, the Participant shall have all of the rights of a shareholder of the Company holding shares of Stock, including the right to vote such shares and to receive all dividends and other distributions paid with respect to such shares. However, in the event of a dividend or distribution paid in shares of Stock or any other adjustment made upon a change in the capital structure of the Company as described in Section 4.2 , any and all new, substituted or additional securities or other property (other than normal cash dividends) to which the Participant is entitled by reason of the Participant's Restricted Stock Award shall be immediately subject to the same Vesting Conditions as the shares subject to the Restricted Stock Award with respect to which such dividends or distributions were paid or adjustments were made.

9.6 **Effect of Termination of Service.** Unless otherwise provided by the Committee in the grant of a Restricted Stock Award and set forth in the Award Agreement, if a Participant's Service terminates for any reason, whether voluntary or involuntary (including the Participant's death or disability), then the Participant shall forfeit to the Company any shares acquired by the Participant pursuant to a Restricted Stock Award which remain subject to Vesting Conditions as of the date of the Participant's termination of Service in exchange for the payment of the purchase price, if any, paid by the Participant. The Company shall have the right to assign at any time any repurchase right it may have, whether or not such right is then exercisable, to one or more persons as may be selected by the Company.

9.7 **Nontransferability of Restricted Stock Award Rights.** Prior to the issuance of shares of Stock pursuant to a Restricted Stock Award, rights to acquire such shares shall not be subject in any manner to anticipation, alienation, sale, exchange, transfer, assignment, pledge, encumbrance or garnishment by creditors of the Participant or the Participant's beneficiary, except transfer by will or the laws of descent and distribution. All rights with respect to aRestricted Stock Award granted to a Participant hereunder shall be exercisable during his or her lifetime only by such Participant or the Participant's guardian or legal representative.

10. **Terms and Conditions of Performance Awards .**

Performance Awards shall be evidenced by Award Agreements in such form as the Committee shall from time to time establish. No Performance Award or purported

Performance Award shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing Performance Awards may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions:

10.1 **Types of Performance Awards Authorized.** Performance Awards may be in the form of either Performance Shares or Performance Units. Each Award Agreement evidencing a Performance Award shall specify the number of Performance Shares or Performance Units subject thereto, the Performance Award Formula, the Performance Goal(s) and Performance Period applicable to the Award, and the other terms, conditions and restrictions of the Award.

10.2 **Initial Value of Performance Shares and Performance Units.** Unless otherwise provided by the Committee in granting a Performance Award, each Performance Share shall have an initial value equal to the Fair Market Value of one (1) share of Stock, subject to adjustment as provided in Section 4.2 , on the effective date of grant of the Performance Share. Each Performance Unit shall have an initial value determined by the Committee. The final value payable to the Participant in settlement of a Performance Award determined on the basis of the applicable Performance Award Formula will depend on the extent to which Performance Goals established by the Committee are attained within the applicable Performance Period established by the Committee.

10.3 **Establishment of Performance Period, Performance Goals and Performance Award Formula.** In granting each Performance Award, the Committee shall establish in writing the applicable Performance Period, Performance Award Formula and one or more Performance Goals which, when measured at the end of the Performance Period, shall determine on the basis of the Performance Award Formula the final value of the Performance Award to be paid to the Participant. To the extent compliance with the requirements under Section 162(m) with respect to "performance-based compensation" is desired, the Committee shall establish the Performance Goal(s) and Performance Award Formula applicable to each Performance Award no later than the earlier of (a) the date ninety (90) days after the commencement of the applicable Performance Period or (b) the date on which 25% of the Performance Period has elapsed, and, in any event, at a time when the outcome of the Performance Goals remains substantially uncertain. Once established, the Performance Goals and Performance Award Formula shall not be changed during the Performance Period. The Company shall notify each Participant granted a Performance Award of the terms of such Award, including the Performance Period, Performance Goal(s) and Performance Award Formula.

10.4 **Measurement of Performance Goals.** Performance Goals shall be established by the Committee on the basis of targets to be attained (" ***Performance Targets*** ") with respect to one or more measures of business or financial performance (each, a " ***Performance Measure*** "), subject to the following:

(a) ***Performance Measures.*** Performance Measures shall have the same meanings as used in the Company's financial statements, or, if such terms are not used in the Company's financial statements, they shall have the meaning applied pursuant to generally accepted accounting principles, or as used generally in the Company's industry. Performance Measures shall be calculated with respect to the Company and each Subsidiary Corporation

consolidated therewith for financial reporting purposes or such division or other business unit as may be selected by the Committee. For purposes of the Plan, the Performance Measures applicable to a Performance Award shall be calculated in accordance with generally accepted accounting principles, but prior to the accrual or payment of any Performance Award for the same Performance Period and excluding the effect (whether positive or negative) of any change in accounting standards or any extraordinary, unusual or nonrecurring item, as determined by the Committee, occurring after the establishment of the Performance Goals applicable to the Performance Award. Each such adjustment, if any, shall be made solely for the purpose of providing a consistent basis from period to period for the calculation of Performance Measures in order to prevent the dilution or enlargement of the Participant's rights with respect to a Performance Award. Performance Measures may be one or more of the following, as determined by the Committee: (i) sales revenue; (ii) gross margin; (iii) operating margin; (iv) operating income; (v) pre-tax profit; (vi) earnings before interest, taxes and depreciation and amortization; (vii) net income; (viii) expenses; (ix) the market price of the Stock; (x) earnings per share; (xi) return on shareholder equity; (xii) return on capital; (xiii) return on net assets; (xiv) economic value added; and (xv) market share; (xvi) customer service; (xvii) customer satisfaction; (xviii) safety; (xix) total shareholder return; or (xx) such other measures as determined by the Committee consistent with this Section 10.4(a).

(b) ***Performance Targets.*** Performance Targets may include a minimum, maximum, target level and intermediate levels of performance, with the final value of a Performance Award determined under the applicable Performance Award Formula by the level attained during the applicable Performance Period. A Performance Target may be stated as an absolute value or as a value determined relative to a standard selected by the Committee.

10.5 **Settlement of Performance Awards.**

(a) ***Determination of Final Value.*** As soon as practicable following the completion of the Performance Period applicable to a Performance Award, the Committee shall certify in writing the extent to which the applicable Performance Goals have been attained and the resulting final value of the Award earned by the Participant and to be paid upon its settlement in accordance with the applicable Performance Award Formula.

(b) ***Discretionary Adjustment of Award Formula.*** In its discretion, the Committee may, either at the time it grants a Performance Award or at any time thereafter, provide for the positive or negative adjustment of the Performance Award Formula applicable to a Performance Award that is not intended to constitute "qualified performance based compensation" to a "covered employee" within the meaning of Section 162(m) (a " ***Covered Employee*** ") to reflect such Participant's individual performance in his or her position with the Company or such other factors as the Committee may determine. With respect to a Performance Award intended to constitute qualified performance-based compensation to a Covered Employee, the Committee shall have the discretion to reduce some or all of the value of the Performance Award that would otherwise be paid to the Covered Employee upon its settlement notwithstanding the attainment of any Performance Goal and the resulting value of the Performance Award determined in accordance with the Performance Award Formula.

(c) ***Payment in Settlement of Performance Awards.*** As soon as practicable following the Committee's determination and certification in accordance with Sections 10.5 (a) and (b) , payment shall be made to each eligible Participant (or such Participant's legal representative or other person who acquired the right to receive such payment by reason of the Participant's death) of the final value of the Participant's Performance Award. Payment of such amount shall be made in cash, shares of Stock, or a combination thereof as determined by the Committee.

10.6 **Voting Rights, Dividend Equivalent Rights and Distributions.** Participants shall have no voting rights with respect to shares of Stock represented by Performance Share Awards until the date of the issuance of such shares, if any (as evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company). However, the Committee, in its discretion, may provide in the Award Agreement evidencing any Performance Share Award that the Participant shall be entitled to receive Dividend Equivalents with respect to the payment of cash dividends on Stock having a record date prior to the date on which the Performance Shares are settled or forfeited. Such Dividend Equivalents, if any, shall be credited to the Participant in the form of additional whole Performance Shares as of the date of payment of such cash dividends on Stock. The number of additional Performance Shares (rounded to the nearest whole number) to be so credited shall be determined by dividing (a) the amount of cash dividends paid on such date with respect to the number of shares of Stock represented by the Performance Shares previously credited to the Participant by (b) the Fair Market Value per share of Stock on such date. Dividend Equivalents may be paid currently or may be accumulated and paid to the extent that Performance Shares become nonforfeitable, as determined by the Committee. Settlement of Dividend Equivalents may be made in cash, shares of Stock, or a combination thereof as determined by the Committee, and may be paid on the same basis as settlement of the related Performance Share as provided in Section 10.5 . Dividend Equivalents shall not be paid with respect to Performance Units. In the event of a dividend or distribution paid in shares of Stock or any other adjustment made upon a change in the capital structure of the Company as described in Section 4.2 , appropriate adjustments shall be made in the Participant's Performance Share Award so that it represents the right to receive upon settlement any and all new, substituted or additional securities or other property (other than normal cash dividends) to which the Participant would be entitled by reason of the shares of Stock issuable upon settlement of the Performance Share Award, and all such new, substituted or additional securities or other property shall be immediately subject to the same Performance Goals as are applicable to the Award.

10.7 **Effect of Termination of Service.** Unless otherwise provided by the Committee in the grant of a Performance Award and set forth in the Award Agreement, the effect of a Participant's termination of Service on the Performance Award shall be as follows:

(a) ***Death or Disability.*** If the Participant's Service terminates because of the death or Disability of the Participant before the completion of the Performance Period applicable to the Performance Award, the final value of the Participant's Performance Award shall be determined by the extent to which the applicable Performance Goals have been attained with respect to the entire Performance Period and shall be prorated based on the number of months of the Participant's Service during the Performance Period. Payment shall be made following the end of the Performance Period in any manner permitted by Section 10.5 .

(b) ***Other Termination of Service.*** If the Participant's Service terminates for any reason except death or Disability before the completion of the Performance Period applicable to the Performance Award, such Award shall be forfeited in its entirety; provided, however, that in the event of an involuntary termination of the Participant's Service, the Committee, in its sole discretion, may waive the automatic forfeiture of all or any portion of any such Award.

10.8 **Nontransferability of Performance Awards.** Prior to settlement in accordance with the provisions of the Plan, no Performance Award shall be subject in any manner to anticipation, alienation, sale, exchange, transfer, assignment, pledge, encumbrance, or garnishment by creditors of the Participant or the Participant's beneficiary, except transfer by will or by the laws of descent and distribution. All rights with respect to a Performance Award granted to a Participant hereunder shall be exercisable during his or her lifetime only by such Participant or the Participant's guardian or legal representative.

11. **Terms and Conditions of Restricted Stock Unit Awards** .

Restricted Stock Unit Awards shall be evidenced by Award Agreements specifying the number of Restricted Stock Units subject to the Award, in such form as the Committee shall from time to time establish. No Restricted Stock Unit Award or purported Restricted Stock Unit Award shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing Restricted Stock Units may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions:

11.1 **Grant of Restricted Stock Unit Awards.** Restricted Stock Unit Awards may be granted upon such conditions as the Committee shall determine, including, without limitation, upon the attainment of one or more Performance Goals described in Section 10.4 . If either the grant of a Restricted Stock Unit Award or the Vesting Conditions with respect to such Award is to be contingent upon the attainment of one or more Performance Goals, the Committee shall follow procedures substantially equivalent to those set forth in Sections 10.3 through 10.5(a) .

11.2 **Vesting.** Restricted Stock Units may or may not be made subject to Vesting Conditions based upon the satisfaction of such Service requirements, conditions, restrictions or performance criteria, including, without limitation, Performance Goals as described in Section 10.4 , as shall be established by the Committee and set forth in the Award Agreement evidencing such Award.

11.3 **Voting Rights, Dividend Equivalent Rights and Distributions.** Participants shall have no voting rights with respect to shares of Stock represented by Restricted Stock Units until the date of the issuance of such shares (as evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company). However, the Committee, in its discretion, may provide in the Award Agreement evidencing any Restricted Stock Unit Award that the Participant shall be entitled to receive Dividend Equivalents with respect to the payment of cash dividends on Stock having a record date prior to the date on which Restricted Stock Units held by such Participant are settled. Such Dividend Equivalents, if any, shall be paid by crediting the Participant with additional whole Restricted Stock Units as of the

date of payment of such cash dividends on Stock. The number of additional Restricted Stock Units (rounded to the nearest whole number) to be so credited shall be determined by dividing (a) the amount of cash dividends paid on such date with respect to the number of shares of Stock represented by the Restricted Stock Units previously credited to the Participant by (b) the Fair Market Value per share of Stock on such date. Such additional Restricted Stock Units shall be subject to the same terms and conditions and shall be settled in the same manner and at the same time (or as soon thereafter as practicable) as the Restricted Stock Units originally subject to the Restricted Stock Unit Award. In the event of a dividend or distribution paid in shares of Stock or any other adjustment made upon a change in the capital structure of the Company as described in Section 4.2 , appropriate adjustments shall be made in the Participant's Restricted Stock Unit Award so that it represents the right to receive upon settlement any and all new, substituted or additional securities or other property (other than normal cash dividends) to which the Participant would be entitled by reason of the shares of Stock issuable upon settlement of the Award, and all such new, substituted or additional securities or other property shall be immediately subject to the same Vesting Conditions as are applicable to the Award.

11.4 **Effect of Termination of Service.** Unless otherwise provided by the Committee in the grant of a Restricted Stock Unit Award and set forth in the Award Agreement, if a Participant's Service terminates for any reason, whether voluntary or involuntary (including the Participant's death or disability), then the Participant shall forfeit to the Company any Restricted Stock Units pursuant to the Award which remain subject to Vesting Conditions as of the date of the Participant's termination of Service.

11.5 **Settlement of Restricted Stock Unit Awards.** The Company shall issue to a Participant on the date on which Restricted Stock Units subject to the Participant's Restricted Stock Unit Award vest or on such other date determined by the Committee, in its discretion, and set forth in the Award Agreement one (1) share of Stock (and/or any other new, substituted or additional securities or other property pursuant to an adjustment described in Section 11.3) for each Restricted Stock Unit then becoming vested or otherwise to be settled on such date, subject to the withholding of applicable taxes. Notwithstanding the foregoing, if permitted by the Committee and set forth in the Award Agreement, the Participant may elect in accordance with terms specified in the Award Agreement to defer receipt of all or any portion of the shares of Stock or other property otherwise issuable to the Participant pursuant to this Section.

11.6 **Nontransferability of Restricted Stock Unit Awards.** Prior to the issuance of shares of Stock in settlement of a Restricted Stock Unit Award, the Award shall not be subject in any manner to anticipation, alienation, sale, exchange, transfer, assignment, pledge, encumbrance, or garnishment by creditors of the Participant or the Participant's beneficiary, except transfer by will or by the laws of descent and distribution. All rights with respect to a Restricted Stock Unit Award granted to a Participant hereunder shall be exercisable during his or her lifetime only by such Participant or the Participant's guardian or legal representative.

12. **Deferred Compensation Awards .**

12.1 **Establishment of Deferred Compensation Award Programs.** This Section 12 shall not be effective unless and until the Committee determines to establish a program pursuant

to this Section. The Committee, in its discretion and upon such terms and conditions as it may determine, may establish one or more programs pursuant to the Plan under which:

(a) Participants designated by the Committee who are Insiders or otherwise among a select group of highly compensated Employees may irrevocably elect, prior to a date specified by the Committee, to reduce such Participant's compensation otherwise payable in cash (subject to any minimum or maximum reductions imposed by the Committee) and to be granted automatically at such time or times as specified by the Committee one or more Awards of Stock Units with respect to such numbers of shares of Stock as determined in accordance with the rules of the program established by the Committee and having such other terms and conditions as established by the Committee.

(b) Participants designated by the Committee who are Insiders or otherwise among a select group of highly compensated Employees may irrevocably elect, prior to a date specified by the Committee, to be granted automatically an Award of Stock Units with respect to such number of shares of Stock and upon such other terms and conditions as established by the Committee in lieu of:

(i) shares of Stock otherwise issuable to such Participant upon the exercise of an Option;

(ii) cash or shares of Stock otherwise issuable to such Participant upon the exercise of an SAR; or

(iii) cash or shares of Stock otherwise issuable to such Participant upon the settlement of a Performance Award or Performance Unit.

12.2 **Terms and Conditions of Deferred Compensation Awards.** Deferred Compensation Awards granted pursuant to this Section 12 shall be evidenced by Award Agreements in such form as the Committee shall from time to time establish. No such Deferred Compensation Award or purported Deferred Compensation Award shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing Deferred Compensation Awards may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions:

(a) ***Vesting Conditions*** . Deferred Compensation Awards shall not be subject to any vesting conditions.

(b) ***Terms and Conditions of Stock Units*** .

(i) **Voting Rights, Dividend Equivalent Rights and Distributions.** Participants shall have no voting rights with respect to shares of Stock represented by Stock Units until the date of the issuance of such shares (as evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company). However, a Participant shall be entitled to receive Dividend Equivalents with respect to the payment of cash dividends on Stock having a record date prior to the date on which Stock Units held by such Participant are settled. Such Dividend Equivalents shall be paid by crediting the Participant with

additional whole and/or fractional Stock Units as of the date of payment of such cash dividends on Stock. The method of determining the number of additional Stock Units to be so credited shall be specified by the Committee and set forth in the Award Agreement. Such additional Stock Units shall be subject to the same terms and conditions and shall be settled in the same manner and at the same time (or as soon thereafter as practicable) as the Stock Units originally subject to the Stock Unit Award. In the event of a dividend or distribution paid in shares of Stock or any other adjustment made upon a change in the capital structure of the Company as described in Section 4.2 , appropriate adjustments shall be made in the Participant's Stock Unit Award so that it represents the right to receive upon settlement any and all new, substituted or additional securities or other property (other than normal cash dividends) to which the Participant would be entitled by reason of the shares of Stock issuable upon settlement of the Award.

(ii) **Settlement of Stock Unit Awards.** A Participant electing to receive an Award of Stock Units pursuant to this Section 12 , shall specify at the time of such election a settlement date with respect to such Award. The Company shall issue to the Participant as soon as practicable following the earlier of the settlement date elected by the Participant or the date of termination of the Participant's Service, a number of whole shares of Stock equal to the number of whole Stock Units subject to the Stock Unit Award. Such shares of Stock shall be fully vested, and the Participant shall not be required to pay any additional consideration (other than applicable tax withholding) to acquire such shares. Any fractional Stock Unit subject to the Stock Unit Award shall be settled by the Company by payment in cash of an amount equal to the Fair Market Value as of the payment date of such fractional share.

(iii) **Nontransferability of Stock Unit Awards.** Prior to their settlement in accordance with the provision of the Plan, no Stock Unit Award shall be subject in any manner to anticipation, alienation, sale, exchange, transfer, assignment, pledge, encumbrance, or garnishment by creditors of the Participant or the Participant's beneficiary, except transfer by will or by the laws of descent and distribution. All rights with respect to a Stock Unit Award granted to a Participant hereunder shall be exercisable during his or her lifetime only by such Participant or the Participant's guardian or legal representative.

13. **Other Stock-Based Awards** .

In addition to the Awards set forth in Sections 6 through 12 above, the Committee, in its sole discretion, may carry out the purpose of this Plan by awarding Stock-Based Awards as it determines to be in the best interests of the Company and subject to such other terms and conditions as it deems necessary and appropriate.

14. **Change in Control** .

14.1 **Effect of Change in Control on Options and SARs .** In the event of a Change in Control, the surviving, continuing, successor, or purchasing corporation or other business entity or parent thereof, as the case may be (the "Acquiror "), may, without the consent of any Participant, either assume or continue the Company's rights and obligations under outstanding Options or SARs or substitute for outstanding Options or SARs substantially equivalent options or SARs covering the Acquiror's stock. Any Options or SARs which are neither assumed or

continued by the Acquiror in connection with the Change in Control nor exercised as of the Change in Control shall, contingent on the Change in Control, become fully vested and exercisable immediately prior to the Change in Control. Options and SARs which are assumed or continued in connection with a Change in Control shall be subject to such additional accelerated vesting and/or exercisability in connection with the Participant's subsequent termination of Service as the Board may determine.

14.2 **Effect of Change in Control on Other Awards .** In the event of a Change in Control, the Acquiror may, without the consent of any Participant, either assume or continue the Company's rights and obligations under outstanding Awards other than Options or SARs or substitute for such Awards substantially equivalent Awards covering the Acquiror's stock. Any such Awards which are neither assumed or continued by the Acquiror in connection with the Change in Control shall, contingent on the Change in Control, become fully vested and all restrictions shall be released immediately prior to the Change in Control. Awards which are assumed or continued in connection with a Change in Control shall be subject to such additional accelerated vesting or lapse of restrictions in connection with the Participant's subsequent termination of Service as the Board may determine.

14.3 **Nonemployee Director Awards** . Notwithstanding the foregoing, Nonemployee Director Awards shall be subject to the terms of Section 7, and not this Section 14.

15. **Compliance with Securities Law .**

The grant of Awards and the issuance of shares of Stock pursuant to any Award shall be subject to compliance with all applicable requirements of federal, state and foreign law with respect to such securities and the requirements of any stock exchange or market system upon which the Stock may then be listed. In addition, no Award may be exercised or shares issued pursuant to an Award unless (a) a registration statement under the Securities Act shall at the time of such exercise or issuance be in effect with respect to the shares issuable pursuant to the Award or (b) in the opinion of legal counsel to the Company, the shares issuable pursuant to the Award may be issued in accordance with the terms of an applicable exemption from the registration requirements of the Securities Act. The inability of the Company to obtain from any regulatory body having jurisdiction the authority, if any, deemed by the Company's legal counsel to be necessary to the lawful issuance and sale of any shares hereunder shall relieve the Company of any liability in respect of the failure to issue or sell such shares as to which such requisite authority shall not have been obtained. As a condition to issuance of any Stock, the Company may require the Participant to satisfy any qualifications that may be necessary or appropriate, to evidence compliance with any applicable law or regulation and to make any representation or warranty with respect thereto as may be requested by the Company.

16. Tax Withholding .

16.1 **Tax Withholding in General.** The Company shall have the right to deduct from any and all payments made under the Plan, or to require the Participant, through payroll withholding, cash payment or otherwise, including by means of a Cashless Exercise or Net Exercise of an Option, to make adequate provision for, the federal, state, local and foreign taxes, if any, required by law to be withheld by the Participating Company Group with respect to an

Award or the shares acquired pursuant thereto. The Company shall have no obligation to deliver shares of Stock, to release shares of Stock from an escrow established pursuant to an Award Agreement, or to make any payment in cash under the Plan until the Participating Company Group's tax withholding obligations have been satisfied by the Participant.

16.2 **Withholding in Shares.** The Company shall have the right, but not the obligation, to deduct from the shares of Stock issuable to a Participant upon the exercise or settlement of an Award, or to accept from the Participant the tender of, a number of whole shares of Stock having a Fair Market Value, as determined by the Company, equal to all or any part of the tax withholding obligations of the Participating Company Group. The Fair Market Value of any shares of Stock withheld or tendered to satisfy any such tax withholding obligations shall not exceed the amount determined by the applicable minimum statutory withholding rates.

17. **Amendment or Termination of Plan .**

The Board or the Committee may amend, suspend or terminate the Plan at any time. However, without the approval of the Company's shareholders, there shall be (a) no increase in the maximum aggregate number of shares of Stock that may be issued under the Plan (except by operation of the provisions of Section 4.2), (b) no change in the class of persons eligible to receive Incentive Stock Options, and (c) no other amendment of the Plan that would require approval of the Company's shareholders under any applicable law, regulation or rule. Notwithstanding the foregoing, only the Board may amend Section 7. No amendment, suspension or termination of the Plan shall affect any then outstanding Award unless expressly provided by the Board or the Committee. In any event, no amendment, suspension or termination of the Plan may adversely affect any then outstanding Award without the consent of the Participant unless necessary to comply with any applicable law, regulation or rule.

18. **Miscellaneous Provisions .**

18.1 **Repurchase Rights .** Shares issued under the Plan may be subject to one or more repurchase options, or other conditions and restrictions as determined by the Committee in its discretion at the time the Award is granted. The Company shall have the right to assign at any time any repurchase right it may have, whether or not such right is then exercisable, to one or more persons as may be selected by the Company. Upon request by the Company, each Participant shall execute any agreement evidencing such transfer restrictions prior to the receipt of shares of Stock hereunder and shall promptly present to the Company any and all certificates representing shares of Stock acquired hereunder for the placement on such certificates of appropriate legends evidencing any such transfer restrictions.

18.2 **Provision of Information.** Each Participant shall be given access to information concerning the Company equivalent to that information generally made available to the Company's common shareholders.

18.3 **Rights as Employee, Consultant or Director.** No person, even though eligible pursuant to Section 5 , shall have a right to be selected as a Participant, or, having been so selected, to be selected again as a Participant. Nothing in the Plan or any Award granted under the Plan shall confer on any Participant a right to remain an Employee, Consultant or Director or

interfere with or limit in any way any right of a Participating Company to terminate the Participant's Service at any time. To the extent that an Employee of a Participating Company other than the Company receives an Award under the Plan, that Award shall in no event be understood or interpreted to mean that the Company is the Employee's employer or that the Employee has an employment relationship with the Company.

18.4 **Rights as a Shareholder.** A Participant shall have no rights as a shareholder with respect to any shares covered by an Award until the date of the issuance of such shares (as evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company). No adjustment shall be made for dividends, distributions or other rights for which the record date is prior to the date such shares are issued, except as provided in Section 4.2 or another provision of the Plan.

18.5 **Fractional Shares.** The Company shall not be required to issue fractional shares upon the exercise or settlement of any Award.

18.6 **Severability** . If any one or more of the provisions (or any part thereof) of this Plan shall be held invalid, illegal or unenforceable in any respect, such provision shall be modified so as to make it valid, legal and enforceable, and the validity, legality and enforceability of the remaining provisions (or any part thereof) of the Plan shall not in any way be affected or impaired thereby.

18.7 **Beneficiary Designation.** Subject to local laws and procedures, each Participant may file with the Company a written designation of a beneficiary who is to receive any benefit under the Plan to which the Participant is entitled in the event of such Participant's death before he or she receives any or all of such benefit. Each designation will revoke all prior designations by the same Participant, shall be in a form prescribed by the Company, and will be effective only when filed by the Participant in writing with the Company during the Participant's lifetime. If a married Participant designates a beneficiary other than the Participant's spouse, the effectiveness of such designation may be subject to the consent of the Participant's spouse. If a Participant dies without an effective designation of a beneficiary who is living at the time of the Participant's death, the Company will pay any remaining unpaid benefits to the Participant's legal representative.

18.8 **Unfunded Obligation.** Participants shall have the status of general unsecured creditors of the Company. Any amounts payable to Participants pursuant to the Plan shall be unfunded and unsecured obligations for all purposes, including, without limitation, Title I of the Employee Retirement Income Security Act of 1974. No Participating Company shall be required to segregate any monies from its general funds, or to create any trusts, or establish any special accounts with respect to such obligations. The Company shall retain at all times beneficial ownership of any investments, including trust investments, which the Company may make to fulfill its payment obligations hereunder. Any investments or the creation or maintenance of any trust or any Participant account shall not create or constitute a trust or fiduciary relationship between the Committee or any Participating Company and a Participant, or otherwise create any vested or beneficial interest in any Participant or the Participant's creditors in any assets of any Participating Company. The Participants shall have no claim against any Participating Company for any changes in the value of any assets which may be invested or reinvested by the Company

with respect to the Plan. Each Participating Company shall be responsible for making benefit payments pursuant to the Plan on behalf of its Participants or for reimbursing the Company for the cost of such payments, as determined by the Company in its sole discretion. In the event the respective Participating Company fails to make such payment or reimbursement, a Participant's (or other individual's) sole recourse shall be against the respective Participating Company, and not against the Company. A Participant's acceptance of an Award pursuant to the Plan shall constitute agreement with this provision.

18.9 **Choice of Law.** Except to the extent governed by applicable federal law, the validity, interpretation, construction and performance of the Plan and each Award Agreement shall be governed by the laws of the State of California, without regard to its conflict of law rules.

PLAN HISTORY AND NOTES TO COMPANY

December 15, 2004	Board adopts Plan with a reserve of 12 million shares.
April 20, 2005	Shareholders approve Plan.
January 1, 2006	Plan Effective Date
February 15, 2006	Change in control provisions are amended
December 20, 2006	Board amends Section 7 containing the terms for automatic awards for Non-Employee Directors, effective January 1, 2007

Exhibit 10.39

PG&E CORPORATION

2006 LONG-TERM INCENTIVE PLAN

RESTRICTED STOCK GRANT

PG&E CORPORATION , a California corporation, hereby grants shares of Restricted Stock to the Recipient named below. The shares of Restricted Stock have been granted under the PG&E Corporation 2006 Long-Term Incentive Plan, as amended on February 15, 2006 and December 20, 2006 (the "LTIP"). The terms and conditions of the Restricted Stock are set forth in this cover sheet and in the attached Restricted Stock Agreement (the "Agreement").

Date of Grant: January 3, 2007 [1]

Name of Recipient: _____

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

Number of Shares of Restricted Stock Granted: _____

By signing this cover sheet, you agree to all of the terms and conditions described in the attached Agreement. You and PG&E Corporation agree to execute such further instruments and to take such further action as may reasonably be necessary to carry out the intent of the attached Agreement. You are also acknowledging receipt of this Grant, the attached Agreement, and a copy of the prospectus describing the LTIP and the Restricted Stock dated January 1, 2007.

Recipient: _____
(Signature)

Attachment

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

[1] Due to the death of former President Gerald Ford on December 26, 2006, the federal government declared January 2, 2007 as a national day of mourning. All federal offices and the New York Stock Exchange were closed that day. Thus, the date of grant for the Restricted Stock is January 3, 2007.

PG&E CORPORATION

2006 LONG-TERM INCENTIVE PLAN

RESTRICTED STOCK AGREEMENT

The LTIP and Other Agreements

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

Grant of Restricted Stock

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

Lapse of Restrictions

As long as you remain employed with PG&E Corporation, the restrictions will lapse as to 20 percent of the total number of shares of Restricted Stock originally subject to this Agreement, as shown above on the cover sheet, on the first business day of January of each of the first, second and third years following the Date of Grant. The restrictions will lapse as to an additional 40 percent of the total number of shares of Restricted Stock on the first business day of January of the fifth year following the Date of Grant; provided, however, that the restrictions will lapse as to this 40 percent on the first business day of January of the third year following the Date of Grant if PG&E Corporation's performance in total shareholder return ("TSR") is at or above the 75 th percentile for the prior three calendar years as compared with the comparator group established from time to time by PG&E Corporation. (Each lapse day is an "Annual Lapse Date"). Except as described below, all shares of Restricted Stock subject to this Agreement as to which the restrictions have not lapsed shall be forfeited upon termination of your employment.

To the extent this Agreement provides for the continued lapse of restrictions following the termination of employment, such continued lapse shall be subject to your continued compliance with certain post-employment restrictions.

Voluntary Termination

In the event that you terminate your employment with PG&E Corporation voluntarily, you will automatically forfeit to PG&E Corporation all of the shares of Restricted Stock as to which the restrictions have not lapsed subject to this Agreement as of the date of such Termination.

Termination for Cause	If your employment with PG&E Corporation is terminated by PG&E Corporation for cause, you will automatically forfeit to PG&E Corporation all shares of Restricted Stock as to which the restrictions have not lapsed subject to this Agreement as of the date of such termination. In general, termination for "cause" means termination of employment because of dishonesty, a criminal offense or violation of a work rule, and will be determined by and in the sole discretion of PG&E Corporation.
Termination other than for Cause	If your employment with PG&E Corporation is terminated by PG&E Corporation other than for cause before the restrictions on your Restricted Stock lapse, and you are an officer in Bands 1-5, the restrictions on your outstanding shares of Restricted Stock that would have lapsed during the period of the "Severance Multiple" under the applicable severance policy shall continue to lapse pursuant to the regular lapse schedule (or sooner, to the extent described below in connection with a Change in Control during such period). In the event of your involuntary termination other than for cause, if you are not an officer in Bands 1-5, the restrictions on your outstanding shares of Restricted Stock that would have lapsed within 12 months following such termination will continue to lapse pursuant to the regular lapse schedule (or sooner, in the event of a Change in Control during such period). All other outstanding shares of Restricted Stock shall automatically be forfeited to PG&E Corporation upon such termination.
Retirement	In the event of your Retirement, the restrictions on your outstanding shares of Restricted Stock will continue to lapse as though your employment had continued. You will be considered to have retired if you are age 55 or older on the date of termination and if you were employed by PG&E Corporation for at least five consecutive years ending on the date of termination of your employment.
Death/Disability	If your employment terminates due to your death or disability, the restrictions on all of your shares of Restricted Stock shall lapse on the next Annual Lapse Date. In the event of a Change in Control after such termination and before such next Annual Lapse Date, the restrictions as to all shares of Restricted Stock shall immediately lapse to the extent described below under "Change in Control."

Termination Due to Disposition of Subsidiary	(1) If your employment is terminated (other than for cause or your voluntary termination) by reason of a divestiture or change in control of a subsidiary of PG&E Corporation, which divestiture or change in control results in such subsidiary no longer qualifying as a subsidiary corporation under Section 424(f) of the Internal Revenue Code of 1986, as amended (the "Code"), or (2) if your employment is terminated (other than for cause or your voluntary termination) coincident with the sale of all or substantially all of the assets of a subsidiary of PG&E Corporation, the restrictions on all shares of Restricted Stock shall lapse in the same manner as for a "Termination other than for cause" described above.
Change in Control	In the event of a Change in Control, the surviving, continuing, successor, or purchasing corporation or other business entity or parent thereof, as the case may be (the "Acquiror "), may, without your consent, either assume or continue PG&E Corporation's rights and obligations under this Agreement or provide substantially equivalent awards associated with the Acquiror's stock. If this Award is neither assumed nor continued by the Acquiror or if the Acquiror does not provide a substantially equivalent award, the restrictions on all of your outstanding shares of Restricted Stock shall automatically lapse and become nonforfeitable immediately preceding, and contingent on, the Change in Control of PG&E Corporation. If the Acquiror assumes or continues PG&E Corporation's rights and obligations under this Agreement or substitutes a substantially equivalent award, TSR shall be calculated by aggregating (a) the TSR of PG&E Corporation for the period from January 1 of the year of the grant to the date of the Change in Control, and (b) the TSR of the Acquiror from the date of the Change in Control to the end of the calendar year preceding the third Annual Lapse Date.
Termination In Connection with a Change in Control	If your employment is terminated in connection with a Change in Control within three months before the Change in Control occurs or within two years following the Change in Control, the restrictions on all of your outstanding shares of Restricted Stock (to the extent the restrictions did not previously lapse upon failure of the Acquiror to assume or continue this Award) shall lapse and become nonforfeitable on the date of termination of your employment. PG&E Corporation shall have the sole discretion to determine whether termination of your employment was made in connection with a Change in Control.

Escrow

The certificates for the Restricted Stock shall be deposited in escrow with the Corporate Secretary of PG&E Corporation to be held in accordance with the provisions of this paragraph. Each deposited certificate shall be accompanied by any assignment documents PG&E Corporation may require you to execute. The deposited certificates shall remain in escrow until such time as the certificates are to be released or otherwise surrendered for cancellation as discussed below.

All dividends, if any, on the Restricted Stock shall be held in escrow and subject to the same restrictions as the shares to which they relate.

Release of Shares and Withholding Taxes

The shares of Restricted Stock held in escrow hereunder shall be subject to the following terms and conditions relating to their release from escrow or their surrender to PG&E Corporation:

- When the restrictions as to your shares of Restricted Stock lapse as described above, the certificates for such shares shall be released from escrow and delivered to you, at your request within thirty (30) days of the applicable Annual Lapse Date.
- Upon termination of your employment, any shares of Restricted Stock as to which the restrictions have not lapsed shall be forfeited and automatically surrendered to PG&E Corporation as provided herein.

Note that you must make arrangements acceptable to PG&E Corporation to satisfy withholding or other taxes that may be due before your shares will be released to you. If you so elect, PG&E Corporation will assist you in selling your shares through a broker so that you can use the sales proceeds to satisfy applicable taxes. You will receive the remaining proceeds in cash. However, if you wish to receive the stock certificates in lieu of selling your shares, you will need to make arrangements to pay the applicable taxes either by check or through payroll deduction. PG&E Corporation will notify you about how to instruct PG&E Corporation to sell your shares when the restrictions lapse or make other arrangements.

Code Section 83(b) Election Under Section 83(a) of the Code, the Fair Market Value of the Restricted Stock on the date any forfeiture restrictions applicable to such Restricted Stock lapse will be reportable as ordinary income at that time. For this purpose, "forfeiture restrictions" include surrender to PG&E Corporation of Restricted Stock as described above. You may elect to be taxed at the time the Restricted Stock is granted to you, rather than when the restrictions lapse by filing an election under Section 83(b) of the Code with the Internal Revenue Service within thirty (30) days after the Date of Grant. Failure to make this filing within the thirty (30) day period will result in the recognition of ordinary income by you (in the event the Fair Market Value of the Restricted Stock increases after the date of purchase) as the forfeiture restrictions lapse. **YOU ACKNOWLEDGE THAT IT IS YOUR SOLE RESPONSIBILITY, AND NOT PG&E CORPORATION'S, TO FILE A TIMELY ELECTION UNDER CODE SECTION 83(b). YOU ARE RELYING SOLELY ON YOUR OWN ADVISORS WITH RESPECT TO THE DECISION AS TO WHETHER OR NOT TO FILE A CODE SECTION 83(b) ELECTION.**

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

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

Voting and Other Rights Subject to the terms of this Agreement, you shall have all the rights and privileges of a shareholder of PG&E Corporation while the Restricted Stock is held in escrow, including the right to vote. As described above, all dividends, if any, on the Restricted Stock shall be held in escrow and subject to the same restrictions as the shares to which they relate.

Restrictions on Issuance PG&E Corporation will not issue any Restricted Stock if the issuance of such Restricted Stock at that time would violate any law or regulation.

Restrictions on Resale and Hedge Transactions

By signing this Agreement, you agree not to sell any Restricted Stock before the restrictions lapse or sell any shares acquired under this grant at a time when applicable laws, regulations or Company or underwriter trading policies prohibit sale. In particular, in connection with any underwritten public offering by PG&E Corporation of its equity securities pursuant to an effective registration statement filed under the Securities Act of 1933, you shall not sell, make any short sale of, loan, hypothecate, pledge, grant any option for the purchase of, or otherwise dispose or transfer for value or agree to engage in any of the foregoing transactions with respect to any shares acquired under this grant without the prior written consent of PG&E Corporation or its underwriters, for such period of time after the effective date of such registration statement as may be requested by PG&E Corporation or the underwriters.

If the sale of shares acquired under this grant is not registered under the Securities Act of 1933, but an exemption is available which requires an investment or other representation and warranty, you shall represent and agree that the Shares being acquired are being acquired for investment, and not with a view to the sale or distribution thereof, and shall make such other representations and warranties as are deemed necessary or appropriate by PG&E Corporation and its counsel.

By your acceptance of the grant, you agree that while the Restricted Stock is subject to restrictions, you will not enter into a corresponding hedging transaction relating to PG&E Corporation's stock nor engage in any short sale of PG&E Corporation's stock. This prohibition shall not apply to transactions effected through PG&E Corporation's benefit plans that provide an opportunity to invest in Company stock or which provide compensation based on the price of Company stock.

No Retention Rights

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

Legends	All certificates that may be issued to represent the Restricted Stock issued under this grant shall, where applicable, have endorsed thereon the following legends: "THE SHARES REPRESENTED BY THIS CERTIFICATE ARE SUBJECT TO CERTAIN RESTRICTIONS ON TRANSFER SET FORTH IN AN AGREEMENT BETWEEN PG&E CORPORATION AND THE REGISTERED HOLDER, OR HIS OR HER PREDECESSOR IN INTEREST. A COPY OF SUCH AGREEMENT IS ON FILE AT THE PRINCIPAL OFFICE OF PG&E CORPORATION AND WILL BE FURNISHED UPON WRITTEN REQUEST TO THE CORPORATE SECRETARY OF PG&E CORPORATION BY THE HOLDER OF RECORD OF THE SHARES REPRESENTED BY THIS CERTIFICATE."
Applicable Law	This Agreement will be interpreted and enforced under the laws of the State of California.

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

Exhibit 10.44

PG&E CORPORATION

2006 LONG-TERM INCENTIVE PLAN

PERFORMANCE SHARE GRANT

PG&E CORPORATION , a California corporation, hereby grants Performance Shares to the Recipient named below. The Performance Shares have been granted under the PG&E Corporation 2006 Long-Term Incentive Plan, as amended on February 15, 2006 and December 20, 2006 (the "LTIP"). The terms and conditions of the Performance Shares are set forth in this cover sheet and the attached Performance Share Agreement (the "Agreement").

Date of Grant: January 3, 2007 [1]

Name of Recipient: _____

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

Number of Performance Shares: _____

By signing this cover sheet, you agree to all of the terms and conditions described in the attached Agreement. You and PG&E Corporation agree to execute such further instruments and to take such further action as may reasonably be necessary to carry out the intent of the attached Agreement. You are also acknowledging receipt of this Grant, the attached Agreement, and a copy of the prospectus describing the LTIP and the Performance Shares dated January 1, 2007.

Recipient: _____
(Signature)

Attachment

Please sign and return to PG&E Corporation, Human Resources,

One Market, Spear Tower, Suite 400, San Francisco, California 94105

[1] Due to the death of former President Gerald Ford on December 26, 2006, the federal government declared January 2, 2007 as a national day of mourning. All federal offices and the New York Stock Exchange were closed that day. Thus, the date of grant for the Performance Shares is January 3, 2007.

PG&E CORPORATION 2006 LONG-TERM INCENTIVE PLAN

PERFORMANCE SHARE AGREEMENT

The LTIP and Other Agreements

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

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

Grant of Performance Shares

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

Vesting of Performance Shares

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

Payment of Performance Shares

Upon the Vesting Date, PG&E Corporation's total shareholder return (TSR) will be compared to the TSR of the twelve other companies in PG&E Corporation's comparator group [2] for the prior three calendar years (the "Performance Period"). Subject to rounding considerations, there will be no payout for TSR below the 25 th percentile of the comparator group; TSR at the 25 th percentile will result in a 25% payout of Performance Shares; TSR at the 75 th percentile will result in a 100% payout of Performance Shares; and TSR in the top rank will result in a 200% payout of Performance Shares. The following table sets forth the payout percentages for the various TSR rankings that could be achieved:

Number of Companies in Total (Including PG&E)		
13		
Rank	Performance Percentile	Rounded Payout
1	100%	200%
2	92%	170%
3	83%	130%
4	75%	100%
5	67%	90%
6	58%	75%
7	50%	65%
8	42%	50%
9	33%	35%
10	25%	25%
11	17%	0%
12	8%	0%
13	0%	0%

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

Dividends

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

Voluntary Termination

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

Termination for Cause

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

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

Termination other than for Cause

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

Retirement

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

Death/Disability

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

Termination Due to Disposition of Subsidiary

(1) If your employment is terminated (other than for cause or your voluntary termination) by reason of a divestiture or change in control of a subsidiary of PG&E Corporation, which divestiture or change in control results in such subsidiary no longer qualifying as a subsidiary corporation under Section 424(f) of the Internal Revenue Code of 1986, as amended, or (2) if your employment is terminated (other than for cause or your voluntary termination) coincident with the sale of all or substantially all of the assets of a subsidiary of PG&E Corporation, all Performance Shares shall vest proportionally based on the number of months during the Performance Period that you were employed (rounded down) divided by the number of months in the Performance Period (36 months). All other outstanding Performance Shares (and any associated accrued dividends) shall automatically be cancelled upon such termination. Your vested Performance Shares will be payable, if at all, after the completion of the Performance Period based on the same formula applied to active employees. You shall also receive a cash payment, if any, equal to the amount of dividends accrued over the Performance Period with respect to your vested Performance Shares multiplied by the same payout percentage used to determine the amount, if any, of the Performance Share payout.

Change in Control

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

If this Award is neither assumed nor continued by the Acquiror or if the Acquiror does not provide a substantially equivalent award in substitution for the Performance Shares subject to this Agreement, all of your outstanding Performance Shares shall automatically vest and become nonforfeitable when the Change in Control of PG&E Corporation occurs before the Vesting Date. Such vested Performance Shares will become payable on the first

business day of the year following the Change in Control. The payment, if any, will be based on PG&E Corporation's TSR for the period from January 1 of the year of grant to the date of the Change in Control compared to the TSR of the other companies in PG&E Corporation's comparator group [3] for the same period. The payment will be calculated by multiplying the number of vested Performance Shares by the payout percentage. The resulting number of Performance Shares will be multiplied by the average closing price of a share of PG&E Corporation common stock for the last 30 calendar days preceding the Change in Control as reported on the New York Stock Exchange. You shall also receive a cash payment, if any, equal to the amount of dividends accrued with respect to your Performance Shares to the first business day of the year following the Change in Control multiplied by the same payout percentage used to determine the amount, if any, of the Performance Share payout.

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

Termination In Connection with a Change in Control

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

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

Withholding Taxes

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

Leaves of Absence

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

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

No Retention Rights

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

Applicable Law

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

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

EXHIBIT 11

PG&E CORPORATION
COMPUTATION OF EARNINGS PER COMMON SHARE

	Year Ended December 31,		
	2006	**2005**	**2004**
(in millions, except per share amounts)			
Net Income	$ 991	$ 917	$ 4,504
Less: distributed earnings to common shareholders	460	449	-
Undistributed earnings	531	468	4,504
Less: undistributed earnings from discontinued operations	-	13	684
Undistributed earnings from continuing operations	$ 531	$ 455	$ 3,820
Common shareholder earnings			
Basic			
Distributed earnings to common shareholders	$ 460	$ 449	$ -
Undistributed earnings allocated to common shareholders - continuing operations	503	433	3,646
Undistributed earnings allocated to common shareholders - discontinued operations	-	12	653
Total common shareholders earnings, basic	$ 963	$ 894	$ 4,299
Diluted			
Distributed earnings to common shareholders	$ 460	$ 449	$ -
Undistributed earnings allocated to common shareholders - continuing operations	504	433	3,650
Undistributed earnings allocated to common shareholders - discontinued operations	-	12	653
Total common shareholders earnings, diluted	$ 964	$ 894	$ 4,303
Weighted average common shares outstanding, basic	346	372	398
9.50% Convertible Subordinated Notes	19	19	19
Weighted average common shares outstanding and participating securities, basic	365	391	417
Weighted average common shares outstanding, basic	346	372	398
Employee stock-based compensation and accelerated share repurchases [(1)]	3	6	7
PG&E Corporation warrants	-	-	2
Weighted average common shares outstanding, diluted	349	378	407
9.50% Convertible Subordinated Notes	19	19	19
Weighted average common shares outstanding and participating securities, diluted	368	397	426
Net earnings per common share, basic			
Distributed earnings, basic [(2)]	$ 1.33	$ 1.21	$ -
Undistributed earnings - continuing operations, basic	1.45	1.16	9.16
Undistributed earnings - discontinued operations, basic	-	0.03	1.64
Total	$ 2.78	$ 2.40	$ 10.80
Net earnings per common share, diluted			
Distributed earnings, diluted	$ 1.32	$ 1.19	$ -
Undistributed earnings - continuing operations, diluted	1.44	1.15	8.97

Undistributed earnings - discontinued operations, diluted	-	0.03	1.60
Total	$ 2.76	$ 2.37	$ 10.57

(1) Includes approximately 1 million, 2 million and 222,000 shares, respectively, of PG&E Corporation common stock treated as outstanding in connection with accelerated share repurchases for the year ended December 31, 2006, December 31, 2005 and December 31, 2004, respectively. The remaining shares of approximately 2 million at December 31, 2006, 4 million at December 31, 2005 and 6.8 million at December 31, 2004, relate to share-based compensation and are deemed to be outstanding per SFAS No. 128 for the purpose of calculating EPS.

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

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

	Year ended December 31,				
	2006	**2005**	**2004**	**2003**	**2002**
Earnings:					
Net income	$ 985	$ 934	$ 3,982	$ 923	$ 1,819
Adjustments for minority interest in losses of less than 100% owned affiliates and the Company's equity in undistributed income (losses) of less than 50% owned affiliates	-	-	-	-	-
Income taxes provision	602	574	2,561	528	1,178
Net fixed charges	801	589	671	964	1,029
Total Earnings	$ 2,388	$ 2,097	$ 7,214	$ 2,415	$ 4,026
Fixed Charges:					
Interest on short-term borrowings and long-term debt, net	$ 770	$ 573	$ 682	$ 947	$ 996
Interest on capital leases	11	1	1	1	2
AFUDC debt	20	15	(12)	16	21
Earnings required to cover the preferred stock dividend and preferred security distribution requirements of majority owned trust	-	-	-	-	10
Total Fixed Charges	$ 801	$ 589	$ 671	$ 964	$ 1,029
Ratios of Earnings to Fixed Charges	2.98	3.56	10.75	2.51	3.91

Note:

For the purpose of computing Pacific Gas and Electric Company's ratios of earnings to fixed charges, "earnings" represent net income adjusted for the minority interest in losses of less than 100% owned affiliates, equity in undistributed income or losses of less than 50% owned affiliates, income taxes and fixed charges (excluding capitalized interest). "Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, AFUDC debt, and earnings required to cover the preferred stock dividend requirements and preferred security distribution requirements of majority-owned trust.

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

	Year ended December 31,				
Earnings:	**2006**	**2005**	**2004**	**2003**	**2002**
Net income	$ 985	$ 934	$ 3,982	$ 923	$ 1,819
Adjustments for minority interest in losses of less than 100% owned affiliates and the Company's equity in undistributed income (losses) of less than 50% owned affiliates	-	-	-	-	-
Income taxes provision	602	574	2,561	528	1,178
Net fixed charges	801	589	671	964	1,029
Total Earnings	$ 2,388	$ 2,097	$ 7,214	$ 2,415	$ 4,026
Fixed Charges:					
Interest on short-term borrowings and long-term debt, net	$ 770	$ 573	$ 682	$ 947	$ 996
Interest on capital leases	11	1	1	1	2
AFUDC debt	20	15	(12)	16	21
Earnings required to cover the preferred stock dividend and preferred security distribution requirements of majority owned trust	-	-	-	-	10
Total Fixed Charges	801	589	671	964	1,029
Preferred Stock Dividends:					
Tax deductible dividends	12	12	9	9	9
Pre-tax earnings required to cover non-tax deductible preferred stock dividend requirements	3	13	34	27	28
Total Preferred Stock Dividends	15	25	43	36	37
Total Combined Fixed Charges and Preferred Stock Dividends	$ 816	$ 614	$ 714	$ 1,000	$ 1,066
Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends	2.93	3.42	10.10	2.42	3.78

Note:

For the purpose of computing Pacific Gas and Electric Company's ratios of earnings to combined fixed charges and preferred stock dividends, "earnings" represent net income adjusted for the minority interest in losses of less than 100% owned affiliates, equity in undistributed income or losses of less than 50% owned affiliates, income taxes and fixed charges (excluding capitalized interest). "Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, AFUDC debt, and earnings required to cover the preferred stock dividend requirements and preferred security distribution requirements of majority-owned trust. "Preferred stock dividends" represent tax deductible dividends and pre-tax earnings that are required to pay the dividends on outstanding preferred securities.

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SELECTED FINANCIAL DATA

(in millions, except per share amounts)	2006	2005	2004 [1]	2003	2002
PG&E Corporation [2]					
For the Year					
Operating revenues	$ 12,539	$ 11,703	$ 11,080	$ 10,435	$ 10,505
Operating income	2,108	1,970	7,118	2,343	3,954
Income from continuing operations	991	904	3,820	791	1,723
Earnings per common share from continuing operations, basic	2.78	2.37	9.16	1.96	4.53
Earnings per common share from continuing operations, diluted	2.76	2.34	8.97	1.92	4.49
Dividends declared per common share [3]	1.32	1.23	-	-	-
At Year-End					
Book value per common share [4]	$ 21.24	$ 19.94	$ 20.90	$ 10.16	$ 8.92
Common stock price per share	47.33	37.12	33.28	27.77	13.90
Total assets	34,803	34,074	34,540	30,175	36,081
Long-term debt (excluding current portion)	6,697	6,976	7,323	3,314	3,715
Rate reduction bonds (excluding current portion)	-	290	580	870	1,160
Energy recovery bonds (excluding current portion)	1,936	2,276	-	-	-
Financial debt subject to compromise	-	-	-	5,603	5,605
Preferred stock of subsidiary with mandatory redemption provisions	-	-	122	137	137
Pacific Gas and Electric Company					
For the Year					
Operating revenues	$ 12,539	$ 11,704	$ 11,080	$ 10,438	$ 10,514
Operating income	2,115	1,970	7,144	2,339	3,913
Income available for common stock	971	918	3,961	901	1,794
At Year-End					
Total assets	$ 34,371	$ 33,783	$ 34,302	$ 29,066	$ 27,593
Long-term debt (excluding current portion)	6,697	6,696	7,043	2,431	2,739
Rate reduction bonds (excluding current portion)	-	290	580	870	1,160
Energy recovery bonds (excluding current portion)	1,936	2,276	-	-	-
Financial debt subject to compromise	-	-	-	5,603	5,605
Preferred stock with mandatory redemption provisions	-	-	122	137	137

[1] Financial data reflects the recognition of regulatory assets provided under the December 19, 2003 settlement agreement entered into among PG&E Corporation, Pacific Gas and Electric Company and the California Public Utilities Commission to resolve Pacific Gas and Electric Company's proceeding under Chapter 11 of the U.S. Bankruptcy Code.

[2] Matters relating to discontinued operations are discussed in Management's Discussion and Analysis of Financial Condition and Results of Operations and in the Notes to the Consolidated Financial Statements.

[3] The Board of Directors of PG&E Corporation declared a cash dividend of $0.30 per share per quarter for the first three quarters of 2005. In the fourth quarter of 2005, the quarterly cash dividend declared was increased to $0.33 per share. See Note 8 of the Notes to the Consolidated Financial Statements for further discussion.

[4] Book value per common share includes the effect of participating securities. The dilutive effect of outstanding stock options and restricted stock are further disclosed in the Notes to the Consolidated Financial Statements.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

PG&E Corporation, incorporated in California in 1995, is a company whose primary purpose is to hold interests in energy-based businesses. The company conducts its business principally through Pacific Gas and Electric Company, or the Utility, a public utility operating in northern and central California. The Utility engages primarily in the businesses of electricity and natural gas distribution, electricity generation, procurement and transmission, and natural gas procurement, transportation and storage. PG&E Corporation became the holding company of the Utility and its subsidiaries on January 1, 1997. Both PG&E Corporation and the Utility are headquartered in San Francisco, California.

The Utility served approximately 5.1 million electricity distribution customers and approximately 4.2 million natural gas distribution customers at December 31, 2006. The Utility had approximately $34.4 billion in assets at December 31, 2006 and generated revenues of approximately $12.5 billion in 2006.

The Utility is regulated primarily by the California Public Utilities Commission, or CPUC, and the Federal Energy Regulatory Commission, or FERC. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas at rates set by the CPUC and the FERC. Rates are set to permit the Utility to recover its authorized " revenue requirements " from customers. Revenue requirements are designed to allow the Utility an opportunity to recover its reasonable costs of providing utility services, including a return of, and a fair rate of return on, its investment in utility facilities, or rate base. Changes in any individual revenue requirement affect customers' rates and could affect the Utility's revenues.

Through October 29, 2004, PG&E Corporation also owned National Energy & Gas Transmission, Inc., or NEGT, formerly known as PG&E National Energy Group, Inc., which engaged in electricity generation and natural gas transportation in the United States and which is accounted for as discontinued operations in PG&E Corporation's financial statements, as discussed in Note 7 of the Notes to the Consolidated Financial Statements.

This is a combined annual report of PG&E Corporation and the Utility and includes separate Consolidated Financial Statements for each of these two entities. PG&E Corporation's Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility and other wholly owned and controlled subsidiaries. The Utility's Consolidated Financial Statements include the accounts of the Utility and its wholly owned and controlled subsidiaries. This combined Management's Discussion and Analysis of Financial Condition and Results of Operations, or MD&A, should be read in conjunction with the Consolidated Financial Statements and Notes to the Consolidated Financial Statements included in this annual report.

Summary of Changes in Earnings per Common Share and Net Income for 2006

PG&E Corporation's diluted earnings per common share, or EPS, for 2006 was $2.76 per share, compared to $2.37 per share in 2005. The increase in diluted EPS for 2006 is primarily due to the FERC's approval of recovery of certain costs the Utility began incurring in 1998 in its capacity as scheduling coordinator, or SC, for its existing wholesale electricity transmission customers, increased gas transmission revenues, fewer litigation settlements, utilization of tax benefits associated with prior capital losses, and a lower number of shares outstanding following the November 2005 repurchase of 31,650,300 shares of PG&E Corporation common stock. These increases in earnings per share were partially offset by the credit the Utility began to provide to customers after the November 2005 issuance of the second series of energy recovery bonds, or ERBs. (For a discussion of the ERBs and this credit, see "Electric Operating Revenues" below and Notes 3 and 6 of the Notes to the Consolidated Financial Statements.)

For 2006, PG&E Corporation's net income increased by $74 million, or 8%, to $991 million, compared to $917 million in 2005. This increase reflects the recognition of recovery of SC costs in 2006 that resulted in an increase to net income of approximately $77 million compared to 2005. Increases in net income associated with gas transmission revenues, fewer litigation settlements, and utilization of tax benefits associated with prior capital losses were offset by the carrying cost credit associated with the second series of ERBs, and other factors.

Key Factors Affecting Results of Operations and Financial Condition

PG&E Corporation's and the Utility's results of operations and financial condition depend primarily on whether the Utility is able to operate its business within authorized revenue requirements which, in part, depend on management's ability to accurately forecast future costs incurred in providing utility service, timely recover its authorized costs, and earn its authorized rate of return. Several factors have had, or are expected to have, a significant impact on PG&E Corporation's and the Utility's results of operations and financial condition, including:

- *The Outcome of Regulatory Proceedings* . The amount of the Utility's revenues and the amount of costs the Utility is authorized to recover from customers are primarily determined through regulatory proceedings. The timing of CPUC and FERC decisions affect when the Utility is able to record the authorized revenues. As described above, the FERC's decision in 2006 to allow the Utility to recover SC costs had a material effect on PG&E Corporation's and the Utility's results of operations. The outcome of various other regulatory proceedings, including the Utility's 2007 General Rate Case, or GRC, also will have a material effect. In the 2007 GRC, the CPUC will determine the amount of the Utility's authorized base revenues for the period 2007 through 2010. The Utility has requested the CPUC to approve a settlement agreement reached in the Utility's 2007 GRC. The proposed revenue requirement provided in the settlement agreement reflects an increase of $222 million in the Utility's electric distribution revenues, an increase of $21 million in gas distribution revenues, and a decrease of $30 million in generation operation revenues for an overall increase of $213 million over the authorized 2006 amounts. The settlement agreement also includes revenue increases for 2008, 2009 and 2010. The revenue requirements authorized in the 2007 GRC will be effective as of January 1, 2007. On February 13, 2007 a proposed decision and an alternate proposed decision were issued in the 2007 GRC. (See further discussion under "Regulatory Matters" below.)

- *Capital Structure.* The Utility's 2006 and 2007 authorized capital structure includes a 52% equity component. For 2006 and 2007, the Utility is authorized to earn a rate of return on equity, or ROE, of 11.35% on its electricity and natural gas distribution and electricity generation rate base. The CPUC will conduct a new cost of capital proceeding to set the Utility's authorized capital structure and rates of return for 2008. The Utility is required to file its 2008 cost of capital application by May 8, 2007.

- *The Success of the Utility's Strategy to Achieve Operational Excellence and Improved Customer Service* . During 2006, the Utility continued to undertake various initiatives to implement changes to its business processes and systems in an effort to provide better, faster and more cost-effective service to its customers. During 2006, the Utility incurred approximately $137 million, including approximately $36 million for employee severance costs, to implement these initiatives. The Utility intends to incur similar costs of approximately $200 million for further implementation of these initiatives in 2007. The proposed amounts of the revenue requirement increases for 2008, 2009 and 2010 included in the proposed 2007 GRC settlement agreement are expected to be adequate in light of the estimated cost savings anticipated to be realized from implementation of these initiatives. If the actual cost savings are greater than anticipated, such benefits would accrue to shareholders. Conversely, if these cost savings are not realized, earnings available for shareholders would be reduced.

- *The Amount and Timing of Capital Expenditures* . In 2006, the CPUC authorized the Utility to make substantial capital expenditures in connection with the construction of new generation facilities estimated to become operational beginning in 2009 and 2010, and the installation of an advanced metering system. In addition, t he Utility has requested regulatory approval for various capital expenditures to fund investments in transmission and distribution infrastructure needed to serve its customers (i.e., to extend the life of existing infrastructure, to replace existing infrastructure and to add new infrastructure to meet already authorized growth). The amount and timing of the Utility's capital expenditures will affect the amount of rate base on which the Utility may earn its authorized ROE. If the CPUC disallowed the Utility from recovering any portion of its capital expenditures from customers the Utility would be unable to earn a ROE on the disallowed amount. (See further discussion under "Capital Expenditures" below.)

- *Changes in Environmental Liabilities and the Outcome of Litigation.* The Utility's operations are subject to extensive federal, state and local environmental laws and permits. Complying with these environmental laws has in the past required significant expenditures for environmental compliance, monitoring and pollution control equipment, as well as for related fees and permits. During 2006, the Utility increased its recorded liability for environmental remediation by $74 million. In addition, during 2006, the Utility paid approximately $295 million to settle a majority of claims relating to alleged exposure to chromium at the Utility's natural gas compressor stations. (See discussion under "Environmental Matters" below and Note 17 of the Notes to Consolidated Financial Statements.)

- *Impact of the Utility's Chapter 11 Reorganization.* The Utility's plan of reorganization under Chapter 11 of the U.S. Bankruptcy Code became effective on April 12, 2004. The plan of reorganization incorporated the terms of a settlement agreement among the CPUC, PG&E Corporation and the Utility, referred to as the Chapter 11 Settlement Agreement. During 2005, the Utility issued two series of ERBs. The first series was issued to refinance the after-tax portion of the settlement regulatory asset established under the Chapter 11 Settlement Agreement. The second series was issued to pre-fund the Utility's tax liability that will be due as the Utility collects the dedicated rate component, or DRC, used to secure repayment of the first series of ERBs from its customers. Until these taxes are fully paid, the Utility provides customers a "carrying cost" credit to compensate customers for the use of proceeds from the second series of ERBs. The equity component of this carrying cost credit of approximately $56 million resulted in a net income decrease in 2006 and is expected to impact net income by approximately $48 million in 2007. The carrying cost credit will decline each year over the term of the ERBs until the ERBs are fully repaid in 2012. Additionally, the Utility recovered net interest costs related to disputed generator claims for the period between the effective date of the plan of reorganization and the first series of ERBs, and for certain energy supplier refund litigation costs, resulting in an increase of approximately $39 million to net income in 2006.

In addition to the key factors discussed above, PG&E Corporation's and the Utility's future results of operation and financial condition are subject to the risk factors discussed in detail in the section entitled "Risk Factors" below.

FORWARD-LOOKING STATEMENTS

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

- the Utility's ability to timely recover costs through rates;
- the outcome of regulatory proceedings, including ratemaking proceedings pending at the CPUC and the FERC;
- the adequacy and price of electricity and natural gas supplies, and the ability of the Utility to manage and respond to the volatility of the electricity and natural gas markets;
- the effect of weather, storms, earthquakes, fires, floods, disease, other natural disasters, explosions, accidents, mechanical breakdowns, acts of terrorism, and other events or hazards on the Utility's facilities and operations, its customers and third parties on which the Utility relies;
- the potential impacts of climate change on the Utility's electricity and natural gas operations;
- changes in customer demand for electricity and natural gas resulting from unanticipated population growth or decline, general economic and financial market conditions, changes in technology including the development of alternative energy sources, or other reasons;
- operating performance of the Utility's Diablo Canyon nuclear generating facilities, or Diablo Canyon, the occurrence of unplanned outages at Diablo Canyon, or the temporary or permanent cessation of operations at Diablo Canyon;
- the ability of the Utility to recognize benefits from its initiatives to improve its business processes and customer service;
- the ability of the Utility to timely complete its planned capital investment projects;

- the impact of changes in federal or state laws, or their interpretation, on energy policy and the regulation of utilities and their holding companies;

- the impact of changing wholesale electric or gas market rules, including the California Independent System Operator's , or CAISO, new rules to restructure the California wholesale electricity market;

- how the CPUC administers the conditions imposed on PG&E Corporation when it became the Utility's holding company;

- the extent to which PG&E Corporation or the Utility incurs costs in connection with pending litigation that are not recoverable through rates, from third parties, or through insurance recoveries;

- the ability of PG&E Corporation and/or the Utility to access capital markets and other sources of credit;

- the impact of environmental laws and regulations and the costs of compliance and remediation ; and

- the effect of municipalization, direct access, community choice aggregation, or other forms of bypass.

For more information about 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, see the discussion under the heading "Risk Factors" below. PG&E Corporation and the Utility do not undertake an obligation to update forward-looking statements, whether in response to new information, future events or otherwise.

RESULTS OF OPERATIONS

The table below details certain items from the accompanying Consolidated Statements of Income for 2006, 2005 and 2004.

	Year ended December 31,		
	2006	2005	2004
(in millions)			
Utility			
Electric operating revenues	$ 8,752	$ 7,927	$ 7,867
Natural gas operating revenues	3,787	3,777	3,213
Total operating revenues	12,539	11,704	11,080
Cost of electricity	2,922	2,410	2,770
Cost of natural gas	2,097	2,191	1,724
Operating and maintenance	3,697	3,399	2,848
Recognition of regulatory assets	-	-	(4,900)
Depreciation, amortization and decommissioning	1,708	1,734	1,494
Total operating expenses	10,424	9,734	3,936
Operating income	2,115	1,970	7,144
Interest income	175	76	50
Interest expense	(710)	(554)	(667)
Other expense, net [1]	(7)	-	(5)
Income before income taxes	1,573	1,492	6,522
Income tax provision	602	574	2,561
Income available for common stock	$ 971	$ 918	$ 3,961
PG&E Corporation, Eliminations and Other [2]			
Operating revenues	$ -	$ (1)	$ -
Operating (gain) expenses	7	(1)	26
Operating loss	(7)	-	(26)
Interest income	13	4	13
Interest expense	(28)	(29)	(130)
Other expense, net [1]	(6)	(19)	(93)
Loss before income taxes	(28)	(44)	(236)
Income tax benefit	(48)	(30)	(95)
Income (loss) from continuing operations	20	(14)	(141)
Discontinued operations [3]	-	13	684
Net income (loss)	$ 20	$ (1)	$ 543
Consolidated Total			
Operating revenues	$ 12,539	$ 11,703	$ 11,080
Operating expenses	10,431	9,733	3,962
Operating income	2,108	1,970	7,118
Interest income	188	80	63
Interest expense	(738)	(583)	(797)
Other expenses, net [1]	(13)	(19)	(98)
Income before income taxes	1,545	1,448	6,286
Income tax provision	554	544	2,466
Income from continuing operations	991	904	3,820
Discontinued operations [3]	-	13	684
Net income	$ 991	$ 917	$ 4,504

[1] Includes preferred stock dividend requirement as other expense.

[2] PG&E Corporation eliminates all intercompany transactions in consolidation.

(3) Discontinued operations reflect items related to its former subsidiary, NEGT. See Note 7 of the Notes to the Consolidated Financial Statements for further discussion.

Utility

The Utility's rates for electricity and natural gas utility services are determined based on its costs of service. The CPUC and the FERC determine the amount of “revenue requirements” that the Utility can collect to recover the Utility's operating and capital costs and earn a fair return. Revenue requirements are primarily determined based on the Utility's forecast of future costs, including the costs of purchasing electricity and natural gas for the Utility's customers. The CPUC also has established ratemaking mechanisms to permit the Utility to timely recover its costs to procure electricity and natural gas for its customers in the energy markets.

The Utility’s revenues for natural gas transmission services are subject to fluctuation because most of the Utility’s intrastate natural gas transmission capacity has not been sold under long-term contracts that provide for recovery of all fixed costs through the collection of fixed reservation charges. Instead, the Utility sells most of its capacity based on the volume of gas the Utility’s customers actually ship, which exposes the Utility to volumetric risk. (See further discussion in the Natural Gas Transportation and Storage section in “Risk Management Activities” below.) In addition, the Utility faces some volumetric risk in collecting its full authorized electric transmission revenue requirement authorized in its Transmission Owner rate case, or TO rate case (see further discussion below).

The GRC is the primary proceeding in which the CPUC determines the amount of revenue requirements the Utility can recover for basic business and operational costs related to its electricity and natural gas distribution and electricity generation operations. The CPUC generally conducts a GRC every three years. The CPUC sets revenue requirements for a three-year period based on a forecast of costs for the first, or test, year. The CPUC may authorize the Utility to receive annual increases (known as attrition adjustments) for the years between GRCs in order to avoid a reduction in earnings in those years due to, among other things, inflation and increases in invested capital. (See the discussion of the proposed settlement of the Utility’s 2007 GRC below under “Regulatory Matters - 2007 General Rate Case.” The settlement proposes that the Utility’s next GRC would occur in 2011 instead of 2010.) In addition, the CPUC generally conducts an annual cost of capital proceeding to determine the Utility's authorized capital structure and the authorized rate of return that the Utility may earn on its electricity and natural gas distribution and electricity generation assets. The cost of capital proceeding establishes relative weightings of common equity, preferred equity, and debt in the Utility's total authorized capital structure for a specific year. The CPUC then establishes the authorized return on each component that the Utility will collect in its authorized rates. The CPUC waived the requirement for the Utility to file a 2007 cost of capital application and allowed the Utility to maintain the 2006 authorized cost of capital and capital structure, including the Utility’s authorized equity component of 52% and the authorized ROE of 11.35%.

The FERC sets the Utility’s rates for electric transmission services. The primary FERC ratemaking proceeding to determine the amount of revenue requirements the Utility can recover for its electric transmission costs and ROE is the TO rate case. A TO rate case is generally held every year and sets rates for a one-year period. The Utility is typically able to charge new rates, subject to refund, before the outcome of the FERC ratemaking review process. (See discussion of the pending TO rate case below under “Regulatory Matters - FERC Transmission Owner Rate Case.”)

The Utility's rates reflect the sum of individual revenue requirement components authorized by the CPUC and the FERC. Changes in any individual revenue requirement affect customers' rates and could affect the Utility's revenues. Pending regulatory proceedings that could result in rate changes and affect the Utility's revenues are discussed below under “ Regulatory Matters. ” In annual true-up proceedings, the Utility requests the CPUC to authorize an adjustment to electric and gas rates to (1) reflect over- and under-collections in the Utility's major electric and gas balancing accounts, and (2) implement various other electricity and gas revenue requirement changes authorized by the CPUC and the FERC. Generally, rate changes become effective on the first day of the following year. Balances in all CPUC-authorized accounts are subject to review, verification audit and adjustment, if necessary, by the CPUC.

The timing of the CPUC and FERC decisions affect when the Utility is able to record authorized revenues. To minimize rate fluctuations between January 1, 2007 and the dates that rate changes from the 2007 GRC and the most recent TO rate case become effective, the CPUC authorized the Utility to continue collecting the same amount of electric revenues after January 1, 2007 as before January 1, 2007. Differences between the amount of revenues collected after January 1, 2007 and the amount authorized in the 2007 GRC will be tracked in regulatory accounts. When the decision is issued, the Utility would record revenues equal to the amount of the difference between authorized revenues and collected revenues that had accumulated since January 1, 2007. Any revenue requirement changes resulting from the pending TO rate case will be deemed to have been effective as of March 1, 2007. In both cases, the Utility would refund any over-collected amounts, with interest, to customers.

The following presents the Utility's operating results for 2006, 2005 and 2004.

Electric Operating Revenues

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

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

(in millions)	2006	2005	2004
Electric revenues	$ 10,871	$ 9,626	$ 9,800
DWR pass-through revenue	(2,119)	(1,699)	(1,933)
Total electric operating revenues	$ 8,752	$ 7,927	$ 7,867
Total electricity sales (in GWh)	64,725	61,150	62,998

The Utility's electric operating revenues increased in 2006 by approximately $825 million, or approximately 10%, compared to 2005 mainly due to the following factors:

- Electricity procurement costs, which are passed through to customers, increased by approximately $490 million. (See "Cost of Electricity" below.)

- The DRC charge related to the ERBs increased by approximately $175 million (see further discussion in Notes 3 and 6 of the Notes to the Consolidated Financial Statements). During 2005, the Utility collected only the DRC for the first series of ERBs that were issued on February 10, 2005. During 2006, the Utility collected the DRC associated with the first series of ERBs and the DRC related to the second series of ERBs, issued on November 9, 2005.

- The Utility recovered approximately $136 million of costs it incurred as a SC, from April 1998 through September 2006, based on a FERC order issued in August of 2006. SC costs incurred after September 2006 and in the future are considered probable of recovery.

- The Utility recognized attrition adjustments to the Utility's authorized 2003 base revenue requirements of approximately $135 million as authorized in the 2003 GRC.

- The Utility recorded approximately $112 million in revenue requirements to recover a pension contribution attributable to the Utility's electric distribution and generation operations. (See "Regulatory Matters - Defined Benefit Pension Plan Contribution" below.)

- Transmission revenues increased by approximately $90 million primarily due to an increase in revenues as authorized in the Utility's last FERC TO rate case.

- The Utility recognized approximately $65 million due to the recovery of net interest costs related to disputed generator claims for the period between April 12, 2004, the effective date of the Utility's plan of reorganization, and February 10, 2005, when the first series of ERBs was issued, and for certain energy supplier refund litigation costs. Recovery of these costs in the Energy Recovery Bond Balancing Account, or ERBBA, was authorized by the CPUC upon their completion of the verification audit in the 2005 annual electric true-up proceeding in September 2006.

- The Utility recovered approximately $59 million of net interest costs related to disputed generator claims incurred after the issuance of the first series of ERBs. Recovery of these costs through the ERBBA was authorized by the CPUC. Costs incurred after December 2006 and in the future are considered probable of recovery. (See "Interest Income" and "Interest Expense" below for further discussion.)

These were partially offset by the following:

- In 2005, the Utility recognized approximately $160 million due to the resolution of the Utility's claims for shareholder incentives related to energy efficiency and other public purpose programs. No similar amount was recorded in 2006.

- In 2005, the Utility recognized approximately $154 million related to revenue requirements associated with the settlement regulatory asset provided under the Chapter 11 Settlement Agreement and the recovery of costs on the deferred tax component of the settlement regulatory asset. No similar amounts were recorded in 2006.

- The carrying cost credit, including both the debt and equity components, associated with the issuance of the second series of ERBs, decreased electric operating revenues by approximately $123 million in 2006 from 2005. The second series of ERBs was issued to pre-fund the Utility's tax liability that will be due as the Utility collects the DRC related to the first series from its customers over the term of the ERBs. Until these taxes are fully paid, the Utility provides customers a carrying cost credit, computed at the Utility's authorized rate of return on rate base to compensate them for the use of proceeds from the second series of ERBs.

The Utility's electric operating revenues increased in 2005 by approximately $60 million, or approximately 1%, compared to 2004 mainly due to the following factors:

- The Utility began collecting the DRC charge related to ERBs in 2005, which together with revenue requirements associated with the ERBBA, increased electric operating revenues by approximately $390 million in 2005 compared to 2004. (See further discussion in Notes 3 and 6 of the Notes to the Consolidated Financial Statements.)

- The Utility recognized approximately $160 million in 2005 due to the resolution of the Utility's claims for shareholder incentives related to energy efficiency and other public purpose programs covering 1994 - 2001. No similar amount was recorded in 2004.

- Miscellaneous other electric operating revenues, including revenues associated with public purpose programs and advanced metering and demand response programs, increased by approximately $140 million.

- The Utility recognized approximately $100 million of revenues in 2005 relating to the Self-Generation Incentive Program. No similar amount was recorded in 2004.

- The Utility recognized attrition adjustments to the Utility's authorized 2003 base revenue requirements, which together with an increase in revenues authorized in the 2004 cost of capital decision, increased electric operating revenues by approximately $90 million, compared to 2004.

- The Utility recognized approximately $80 million in 2005 due to recovery of certain costs incurred in connection with electric industry restructuring. No similar amount was recorded in 2004.

- Electric operating revenues included approximately $70 million in refunds in revenue requirements to customers in 2004, with no similar amount in 2005.

These were partially offset by the following:

- Electricity procurement and transmission costs, which are passed through to customers, decreased by approximately $530 million compared to 2004.

- After the issuance of the first series of ERBs on February 10, 2005, the Utility was no longer able to collect the revenue requirement associated with the settlement regulatory asset, decreasing electric operating revenues by approximately $435 million compared to 2004. (See further discussion in Notes 3 and 6 of the Notes to the Consolidated Financial Statements.)

The Utility expects that its electric operating revenues for the period 2007 through 2010 will increase to the extent authorized by the CPUC in the 2007 GRC. (For further discussion, see "Regulatory Matters" under "2007 General Rate Case" below.) In addition, the Utility expects to continue to collect revenue requirements related to CPUC-approved capital expenditure projects, including the new Utility-owned generation projects and advanced metering infrastructure. (See "Capital Expenditures" below.) The Utility also expects electric transmission revenues will increase on March 1, 2007 subject to the FERC's authorization. (See "Regulatory Matters - FERC Transmission Rate Case" below.)

Cost of Electricity

The Utility's cost of electricity includes electricity purchase costs, hedging costs and the cost of fuel used by its own generation facilities or supplied to other facilities under tolling agreements, but it excludes costs to operate its own generation facilities, which are included in operating and maintenance expense. Electricity purchase costs and the cost of fuel used in Utility-owned generation are passed through to customers in rates. (See "Electric Operating Revenues" above for further details.)

The Utility is required to dispatch, or schedule, all of the electricity resources within its portfolio, including electricity

provided under the DWR 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 load and to sell this additional electricity on the open market. The Utility typically schedules excess electricity when the expected sales proceeds exceed the variable costs to operate a generation facility or buy electricity under an optional contract. Proceeds from the sale of surplus electricity are allocated between the Utility and the DWR based on the percentage of volume supplied by each entity to the Utility's total load. The Utility's net proceeds from the sale of surplus electricity after deducting the portion allocated to the DWR are recorded as a reduction to the cost of electricity.

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

	2006	2005	2004
(in millions)			
Cost of purchased power	$ 3,114	$ 2,706	$ 2,816
Proceeds from surplus sales allocated to the Utility	(343)	(478)	(192)
Fuel used in own generation	151	182	146
Total cost of electricity	$ 2,922	$ 2,410	$ 2,770
Average cost of purchased power per GWh	$ 0.084	$ 0.079	$ 0.082
Total purchased power (GWh)	36,913	34,203	34,525

In 2006, the Utility's cost of electricity increased by approximately $512 million, or 21%, compared to 2005, mainly due to the following factors:

- The increase in total purchased power of 2,710 Gigawatt hours, or GWh, and the increase in the average cost of purchased power of $0.005 per GWh in 2006, compared to 2005, resulted in an increase of approximately $408 million in the cost of purchased power. This was primarily caused by an increase in volume of purchased power due to greater customer demand during the July 2006 “heat storm” (see discussion below under “Regulatory Matters - Catastrophic Events Memorandum Account”) and a decrease in the volume of electricity provided by the DWR to the Utility’s customers. Additionally, the Utility’s service to customers who purchase “bundled” services (e.g. generation, transmission and distribution) grew, further increasing volume.

In 2005, the Utility's cost of electricity decreased by approximately $360 million, or 13%, compared to 2004, mainly due to the following factors:

- Increased electricity production from the Utility’s hydroelectric generation facilities due to above average rainfall during 2005 increased the proceeds from surplus sales allocated to the Utility by $286 million.

- The volume of total purchased power decreased by 322 GWh in 2005 primarily because increased electricity from the Utility’s hydroelectric facilities and Diablo Canyon reduced the amount of electricity the Utility needed to purchase. During 2005, Diablo Canyon’s refueling outage lasted only 41 days compared to 2004 when the outage lasted 129.5 days. Also, the average cost of purchased power decreased by $0.003 per GWh in 2005 from 2004.

The Utility's cost of electricity in 2007 will depend upon electricity prices, the duration of the Diablo Canyon refueling outage, and changes in customer demand which will directly impact the amount of power the Utility will be required to purchase. (See the "Risk Management Activities" section of this MD&A.)

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

Natural Gas Operating Revenues

The Utility sells natural gas and natural gas transportation services to its customers. The Utility's transportation system

transports gas throughout California to the Utility's distribution system, which in turn, delivers natural gas to end-use customers. The Utility also delivers natural gas to off-system markets, primarily in Southern California, in competition with interstate pipelines.

The Utility's natural gas customers consist of two categories: core and non-core customers. The core customer class is comprised mainly of residential and smaller commercial natural gas customers. The non-core customer class is comprised of industrial and larger commercial natural gas customers. The Utility provides natural gas delivery services to all core and non-core customers connected to the Utility's system in its service territory. Core customers can purchase natural gas from alternate energy service providers or elect to have the Utility provide both delivery service and natural gas supply. The Utility does not provide procurement service to non-core customers. If non-core customers would like the Utility to provide them with procurement service they must elect to have core service provided. When the Utility provides both supply and delivery, the Utility refers to the service as natural gas bundled service. In 2006, core customers represented over 99% of the Utility's total customers and approximately 40% of its total natural gas deliveries, while non-core customers comprised less than 1% of the Utility's total customers and approximately 60% of its total natural gas deliveries. Because the Utility sells most of its capacity based on the volume of natural gas the Utility's customers actually ship, the Utility is exposed to volumetric risk.

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

The CPIM is focused on short-term procurement of natural gas. As natural gas prices have become more volatile, the Utility has sought CPUC authority to secure long-term supplies of natural gas and hedge the price risk associated with these contracts outside of the CPIM. (See the "Risk Management Activities" section of this MD&A.) The Utility is at risk to the extent that the CPUC may disallow portions of the hedging costs based on its subsequent review of the Utility's compliance with the filed plan.

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

(in millions)	**2006**	**2005**	**2004**
Bundled natural gas revenues	$ 3,472	$ 3,539	$ 2,943
Transportation service-only revenues	315	238	270
Total natural gas operating revenues	$ 3,787	$ 3,777	$ 3,213
Average bundled revenue per Mcf of natural gas sold	$ 12.89	$ 13.05	$ 10.51
Total bundled natural gas sales (in millions of Mcf)	269	271	280

In 2006, the Utility's natural gas operating revenues increased by approximately $10 million, or less than one percent, compared to 2005. The increase in natural gas operating revenues was primarily due to the following factors:

- The Utility recorded approximately $43 million in revenue requirements for a pension contribution attributable to the Utility's natural gas distribution operations. (See "Regulatory Matters - Defined Benefit Pension Plan Contribution" below.)
- Attrition adjustments to the Utility's 2003 GRC authorized revenue requirements, and revenues authorized in the 2006 cost of capital proceeding contributed approximately $22 million.
- Miscellaneous natural gas revenues increased by approximately $26 million.
- Transportation service-only revenues increased by approximately $77 million, or 32%, primarily as a result of an increase in rates.

These were partially offset by the following:

- The cost of natural gas, which is passed through to customers, decreased by approximately $132 million, as further discussed below under "Cost of Natural Gas."

- In 2005, the Utility recognized approximately $26 million due to the resolution of the Utility's claims for shareholder incentives related to energy efficiency and other public purpose programs. No similar amount was recorded in 2006.

In 2005, the Utility's natural gas operating revenues increased by approximately $564 million, or 18%, compared to 2004. The increase in natural gas operating revenues was mainly due to the following factors:

- Excluding the impact of the 2003 GRC decision, the 2005 cost of capital proceeding, and the Utility's recovery of shareholder incentives relating to energy efficiency and other public purpose programs, bundled natural gas operating revenues increased by approximately $580 million, or 20%. The increase was attributable to an increase in the cost of natural gas, which is passed through to customers, and partially offset by a decrease in the volume of gas purchased.

- Attrition adjustments to the Utility's 2003 GRC authorized revenue requirements, and revenues authorized in the 2005 cost of capital proceeding contributed approximately $42 million in 2005 compared to 2004.

- The Utility recognized approximately $26 million in 2005 due to the resolution of the Utility's claims for shareholder incentives related to energy efficiency and other public purpose programs covering 1994 - 2001. No similar amount was recorded in 2004.

These were partially offset by the following:

- The approval of the 2003 GRC in May 2004 resulted in the Utility recording approximately $52 million in revenues related to 2003 in 2004. No comparable amount was recorded in 2005.

- Transportation service-only revenues decreased by approximately $32 million, or 12%, primarily as a result of a decrease in rates.

The Utility expects that its natural gas operating revenues for 2007 will increase due to an annual rate escalation as authorized in the Gas Accord III Settlement. In addition, the Utility expects that its natural gas operating revenues for the period 2007 through 2010 will increase to the extent authorized by the CPUC in the 2007 GRC and as may be authorized by the CPUC in the new Gas Transmission and Storage Rate Case that will set new rates effective January 1, 2008. (See "Regulatory Matters - Gas Transmission and Storage Rate Case" below.) Finally, future natural gas operating revenues will be impacted by changes in the cost of natural gas.

Cost of Natural Gas

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

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

	2006	2005	2004
(in millions)			
Cost of natural gas sold	$ 1,958	$ 2,051	$ 1,591
Cost of natural gas transportation	139	140	133
Total cost of natural gas	$ 2,097	$ 2,191	$ 1,724
Average cost per Mcf of natural gas sold	$ 7.28	$ 7.57	$ 5.68
Total natural gas sold (in millions of Mcf)	269	271	280

In 2006, the Utility's total cost of natural gas decreased by approximately $94 million, or 4%, compared to 2005, primarily due to a decrease in the average market price of natural gas purchased of approximately $0.29 per thousand cubic feet, or Mcf, or 4%.

In 2005, the Utility's total cost of natural gas increased by approximately $467 million, or 27%, compared to 2004, primarily due to an increase in the average market price of natural gas purchased of approximately $1.89 per Mcf, or 33%, partially offset by a decrease in volume of 9 Mcf, or 3%.

The Utility's cost of natural gas in 2007 will be primarily affected by the prevailing costs of natural gas, which are determined by North American regions that supply the Utility. As discussed above under “Natural Gas Operating Revenues,” the CPUC has authorized the Utility to execute hedges on behalf of its core gas customers. The Utility also has requested the CPUC to approve a settlement agreement that provides for a long-term hedge program. (For further discussion see “Risk Management Activities” below.) The total cost of gas will also be affected by customer demand.

Operating and Maintenance

Operating and maintenance expenses consist mainly of the Utility's costs to operate and maintain its electricity and natural gas facilities, customer accounts and service expenses, public purpose program expenses, and administrative and general expenses. Generally, these expenses are offset by corresponding annual revenues authorized by the CPUC and the FERC in various rate proceedings.

During 2006, the Utility’s operating and maintenance expenses increased by approximately $298 million, or 9%, compared to 2005, mainly due to the following factors:

- Pension contributions as a result of the CPUC-approved settlement (see “Regulatory Matters - Defined Benefit Pension Plan Contribution” below) resulted in an additional $176 million in pension expense.

- Administration expenses for low-income customer assistance programs, the Self-Generation Incentive Program, advanced metering infrastructure and other energy incentives, increased by approximately $125 million.

- Compensation expense increased approximately $54 million, reflecting increased base salaries and incentives.

- Expenses for outside consulting, contracts and various programs and initiatives, including strategies to achieve operational excellence and improved customer service, increased by approximately $50 million.

- Expenses related to the accrual of severance costs as part of the Utility’s strategies to achieve operational excellence and improved customer service increased by approximately $35 million.

- Franchise fee expense and property taxes increased by approximately $21 million. The increase in franchise fee expense was due to higher revenues and franchise fee rates. The increase in property taxes was due to electric plant growth, a tax rate increase, and increases in assessed values in 2006.

The above increases (totaling $461 million) were partially offset by a decrease of $154 million related to an additional reserve made in 2005 to settle the majority of claims related to alleged exposure to chromium at the Utility’s natural gas compressor stations . No similar adjustment was recorded in 2006. Of the $461 million of increased expenses, ap proximately $366 million is recoverable in rates and did not affect net income in 2006. The additional reserve of $154 million is not recoverable in rates.

During 2005, the Utility’s operating and maintenance expenses increased by approximately $551 million, or 19%, compared to 2004, mainly due to the following factors:

- An additional $154 million was reserved to settle the majority of claims related to alleged exposure to chromium at the Utility’s natural gas compressor stations. (See “Legal Matters” in Note 17 of the Notes to the Consolidated Financial Statements for further discussion.)

- Administration expenses for low-income customer assistance programs and community outreach programs increased by approximately $110 million.

- Approximately $100 million in Self-Generation Incentive Program expenses that were deferred in prior periods because no specific revenue recovery mechanism was in place, were recognized in 2005. (See related revenues in “Electric Operating Revenues.”)

- Expenses for outside consulting, contract and legal expense and various programs and initiatives, including strategies to achieve operational excellence and improved customer service, increased by approximately $55 million.

- Natural gas transportation operations charges increased by approximately $60 million mainly due to rate increases for pipeline demand and transportation.

- The estimated cost of environmental remediation related to the Topock and Hinkley gas compressor stations increased expenses by approximately $40 million. (See “Environmental Matters” in Note 17 of the Notes to the Consolidated Financial Statements for further discussion.)

- Property taxes increased approximately $25 million mainly due to higher assessments in 2005.

These increases were partially offset by a decrease of approximately $50 million in operating and maintenance expenses at Diablo Canyon in 2005 compared to 2004 when there was a longer refueling outage.

Approximately $306 million of the above net increase was recoverable in rates and did not affect net income for 2005.

Operating and maintenance expenses are influenced by wage inflation, benefits, property taxes, the timing and length of Diablo Canyon refueling outages, environmental remediation costs, legal costs and various other administrative and general expenses. The Utility’s operating and maintenance expenses in 2007 are expected to increase as a result of increased expenses related to various programs and initiatives, including public purpose programs and strategies to achieve operational excellence and improved customer service. (See “Overview” section in this MD&A for further discussion.) In connection with the Utility’s continued effort to streamline processes to achieve cost and operating efficiencies, jobs from numerous locations around California are being consolidated and a number of positions have been eliminated. Impacted employees may elect severance or reassignment. As discussed above, the Utility has already incurred approximately $35 million in severance costs relating to the positions that have already been eliminated. The Utility expects that more positions will be eliminated and estimates that it may incur up to approximately $33 million for future severance expenses that would be included in future operating and maintenance expenses. (See further discussion in Note 17 of the Notes to the Consolidated Financial Statements.)

Recognition of Regulatory Assets

The Utility recorded the regulatory assets provided for under the Chapter 11 Settlement Agreement in the first quarter of 2004. This resulted in 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 2006, the Utility's depreciation, amortization and decommissioning expenses decreased by approximately $26 million, or 1%, compared to 2005, mainly due to the following factors:

- The Utility recorded approximately $141 million in 2005 for amortization of the settlement regulatory asset. Because the settlement regulatory asset was refinanced with the issuance of the first series of ERBs on February 10, 2005, the Utility had no similar amount in 2006.

- In 2005, the Utility recorded depreciation expense of approximately $30 million related to recovery of capital plant costs associated with electric industry restructuring costs that a December 2004 settlement agreement allowed the Utility to collect through rates in 2005. There was no similar depreciation expense in 2006.

- Amortization of the regulatory asset related to rate recovery bonds, or RRBs, decreased by approximately $19 million in 2006, compared to 2005, due to the declining balance of the RRBs.

These were partially offset by the following:

- An increase of approximately $137 million related to the amortization of the ERB regulatory asset. During 2005, the Utility amortized only the ERB regulatory asset for the first series of ERBs that were issued on February 10, 2005. During 2006, the Utility amortized the ERB regulatory asset for the second series of ERBs that were issued on November 9, 2005 in addition to the first series.

- Depreciation expense increased by approximately $35 million as a result of plant additions in 2006.

In 2005, the Utility's depreciation, amortization and decommissioning expenses increased by approximately $240 million, or 16%, compared to 2004, mainly due to the following factors:

- The Utility recorded additional amortization expense of approximately $202 million in 2005 as it began to amortize the ERB regulatory

asset.

- In 2004, following the 2003 GRC decision in May 2004 that authorized lower depreciation rates, the Utility recorded an approximately $38 million decrease to depreciation expense. There was no similar reduction in 2005.

- The Utility recorded depreciation expense of approximately $30 million related to recovery of capital plant costs associated with electric industry restructuring costs the December 2004 settlement agreement allowed the Utility to collect through rates. There was no similar depreciation expense in 2004.

These were partially offset by the following:

- Amortization of the regulatory asset related to the RRBs decreased by approximately $20 million in 2005 compared to 2004 again reflecting the declining balance of the RRBs.

- Amortization of the settlement regulatory asset decreased by approximately $10 million in 2005 reflecting the refinancing of the settlement regulatory asset with the ERBs.

The Utility's depreciation, amortization and decommissioning expenses in 2007 are expected to increase as a result of an overall increase in capital expenditures.

Interest Income

In 2006, the Utility's interest income increased by approximately $99 million, or 130%, compared to 2005, primarily due to an increase in interest earned on escrow related to disputed generator claims which are passed through to customers (see "Electric Operating Revenues" above for further discussion), a FERC decision approving recovery of SC costs, including interest , and an increase in interest rates associated with certain regulatory balancing accounts. These increases were partially offset by a decrease in interest earned on short-term investments as a result of lower short-term investment balances.

In 2005, the Utility's interest income increased by approximately $26 million, or 52%, compared to 2004, primarily due to a higher balance and rate of return on short-term investments in 2005 compared to 2004.

The Utility's interest income in 2007 will be primarily affected by interest rate levels.

Interest Expense

In 2006, the Utility's interest expense increased by approximately $156 million, or 28%, compared to 2005, primarily due to an increase in interest expense related to disputed generator claims which are recovered as an offset to interest income (net interest costs) through the ERBBA (see "Electric Operating Revenues" above for further discussion), interest expense associated with the ERBs and accrued interest on higher balances in certain regulatory balancing accounts combined with an increase in the interest rates associated with these accounts. These increases were partially offset by lower interest expense on the RRBs due to their declining balance.

In 2005, the Utility's interest expense decreased by approximately $113 million, or 17%, compared to 2004, primarily due to a decrease in net interest costs on disputed generator claims and energy crisis interest expense incurred in 2004 prior to the Utility's emergence from Chapter 11. In addition, the net additional interest expense of approximately $76 million resulting from the ERB refinancing was offset by a decrease in interest expense of approximately $18 million related to the RRBs and a decrease in interest expense of approximately $56 million incurred on a lower amount of outstanding short-term debt.

The Utility's interest expense in 2007 and subsequent periods will be impacted by changes in interest rates as the Utility's short-term debt and a portion of its long-term debt are interest rate-sensitive. In addition, future interest expense is expected to increase due to higher expected financing resulting from an overall increase in infrastructure investments.

Income Tax Expense

In 2006, the Utility's income tax expense increased by approximately $28 million, or 5%, compared to 2005, primarily due to the increase in pre-tax income of $79 million for 2006. The effective tax rate remained 38% for both 2006 and 2005.

In 2005, the Utility's tax expense decreased by approximately $2.0 billion, or 78%, compared to 2004, mainly due to a decrease in pre-

tax income of approximately $5.0 billion in 2005. This decrease is primarily the result of the recognition of regulatory assets associated with the Chapter 11 Settlement Agreement in 2004 with no similar amount recognized in 2005. The effective tax rate for 2005 decreased from 2004 by 1.3 percentage points to 38%. This decrease was mainly due to increased investment tax credits

in 2005.

PG&E Corporation, Eliminations and Others

Operating Revenues and Expenses

PG&E Corporation's revenues consist mainly of billings to its affiliates for services rendered, all of which are eliminated in consolidation. PG&E Corporation's operating expenses consist mainly of employee compensation and payments to third parties for goods and services. Generally, PG&E Corporation's operating expenses are allocated to affiliates. These allocations are made without mark-up and are eliminated in consolidation.

There were no material changes to PG&E Corporation’s operating income in 2006 compared to 2005.

PG&E Corporation’s operating expenses in 2005 decreased by $27 million, or 104%, compared to 2004, primarily due to an increase in expenses allocated to affiliates.

Interest Expense

There were no material changes to PG&E Corporation’s interest expense in 2006 compared to 2005. PG&E Corporation's interest expense is not allocated to its affiliates.

PG&E Corporation’s interest expense in 2005 decreased $101 million, or 78%, compared to 2004, primarily due to the redemption of PG&E Corporation’s 6 $^{7}/_{8}$% Senior Secured Notes due 2008, on November 15, 2004.

Other Expense

There were no material changes to PG&E Corporation’s other expense in 2006 compared to 2005.

PG&E Corporation’s other expense in 2005 decreased $74 million, or 80%, compared to 2004, primarily due to a decrease in the pre-tax charge to earnings related to the change in market value of non-cumulative dividend participation rights included within PG&E Corporation’s $280 million of 9.50% Convertible Subordinated Notes due 2010, or Convertible Subordinated Notes.

Income Tax Benefit

PG&E Corporation’s income tax benefit in 2006 increased approximately $18 million, or 60%, compared to 2005 primarily due to tax benefits related to capital losses carried forward and used in PG&E Corporation’s 2005 federal and state income tax returns.

PG&E Corporation has $229 million of remaining capital loss carry forwards, which if not used by December 2009, will expire. These capital losses resulted from PG&E Corporation’s disposition of its ownership interest in NEGT in 2004 (as discussed further below).

Discontinued Operations

In 2005, PG&E Corporation received additional information from NEGT regarding income to be included in PG&E Corporation's 2004 federal income tax return and amounts previously included in their 2003 federal income tax return. As a result, PG&E Corporation’s 2004 federal income tax liability was reduced by approximately $19 million and the 2003 federal income tax liability increased by $6 million, respectively. These two adjustments, netting to $13 million, were recognized in income from discontinued operations in 2005.

In 2004, NEGT's plan of reorganization became effective, at which time NEGT emerged from Chapter 11 and PG&E Corporation's equity ownership in NEGT was cancelled. As a result, PG&E Corporation recorded a gain on disposal of NEGT, net of tax, on its Consolidated Statements of Income for approximately $684 million.

For further discussion on discontinued operations relating to NEGT, see Note 7 of the Notes to the Consolidated Financial Statements.

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.

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

At December 31, 2006, PG&E Corporation and its subsidiaries had consolidated cash and cash equivalents of approximately $456 million and restricted cash of approximately $1.4 billion. At December 31, 2006, PG&E Corporation on a stand alone basis had cash and cash equivalents of approximately $386 million; the Utility had cash and cash equivalents of approximately $70 million, and restricted cash of approximately $1.4 billion. Restricted cash primarily consists of approximately $1.3 billion, including interest, in cash held in escrow pending the resolution of the remaining disputed Chapter 11 claims as well as deposits made by customers and other third parties under certain agreements. PG&E Corporation and the Utility maintain separate bank accounts. PG&E Corporation and the Utility primarily invest their cash in institutional money market funds.

The Utility seeks to maintain or strengthen its credit ratings to provide liquidity through efficient access to financial and trade credit, and to reduce financing costs. As of February 16, 2007, the credit ratings on various financing instruments from Moody's Investors Service, or Moody's, and Standard & Poor's Ratings Service, or S&P, were as follows:

	Moody's	S&P
Utility		
Corporate credit rating	Baa1	BBB
Senior unsecured debt	Baa1	BBB
Pollution control bonds backed by bond insurance	Aaa	AAA
Pollution control bonds backed by letters of credit	- [1]	AA-/A-1+
Credit facility	Baa1	BBB
Preferred stock	Baa3	BB+
Commercial paper program	P-2	A-2
PG&E Funding LLC		
Rate reduction bonds	Aaa	AAA
PG&E Energy Recovery Funding LLC		
Energy recovery bonds	Aaa	AAA
PG&E Corporation		
Credit facility	Baa3	-

[1] Moody ' s has not assigned a rating to the Utility ' s pollution control bonds backed by letters of credit.

Moody's and S&P are nationally recognized credit rating organizations. These ratings may be subject to revision or withdrawal at any time by the assigning rating organization and each rating should be evaluated independently of any other rating. A credit rating is not a recommendation to buy, sell or hold securities.

As of December 31, 2006, PG&E Corporation and the Utility had credit facilities totaling $200 million and $2 billion, respectively, with remaining borrowing capacity on these credit facilities of $200 million and approximately $1.1 billion, respectively. As of December 31, 2006, the Utility had $144 million of letters of credit outstanding issued under its working capital facility, $460 million of outstanding borrowings under the commercial paper program, and $300 million outstanding under its accounts receivable facility. The Utility is seeking an increase to its bank credit facilities as its accounts receivable facility will expire on March 5, 2007.

The Utility plans to maintain approximately $800 million of unused borrowing capacity to provide liquidity in the event of contingencies such as increases in energy procurement costs and collateral requirements. The Utility eliminated the use of cash as a component of its minimum liquidity reserve in July 2006 and now relies solely on access to the commercial paper market and back-up committed credit lines.

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

The Utility anticipates that it will issue approximately $1.35 billion of long-term debt in 2007 primarily to fund capital expenditures.

Dividends

PG&E Corporation and the Utility did not declare or pay a dividend during the Utility's Chapter 11 proceeding. With the Utility's emergence from Chapter 11 on April 12, 2004, the Utility resumed the payment of preferred stock dividends. The Utility reinstated the payment of a regular quarterly common stock dividend to PG&E Corporation in January 2005, upon the achievement of the 52% equity ratio targeted in the Chapter 11 Settlement Agreement.

The dividend policies of PG&E Corporation and the Utility are designed to meet the following three objectives:

- Comparability: Pay a dividend competitive with the securities of comparable companies based on payout ratio (the proportion of earnings paid out as dividends) and, with respect to PG&E Corporation, yield (i.e., dividend divided by share price);

- Flexibility: Allow sufficient cash to pay a dividend and to fund investments while avoiding having to issue new equity unless PG&E Corporation's or the Utility's capital expenditure requirements are growing rapidly and PG&E Corporation or the Utility can issue equity at reasonable cost and terms; and

- Sustainability: Avoid reduction or suspension of the dividend despite fluctuations in financial performance except in extreme and unforeseen circumstances.

The target dividend payout ratio range is 50% to 70% of PG&E Corporation’s earnings. Dividends are expected to remain in the lower end of PG&E Corporation’s target payout range in order to ensure that equity funding is readily available to support capital investment needs.

The Boards of Directors retain authority to change their common stock dividend policy and dividend payout ratio at any time, especially if unexpected events occur that would change the Boards’ view as to the prudent level of cash conservation. No dividend is payable unless and until declared by the applicable Board of Directors.

During 2006, the Utility paid cash dividends to holders of its preferred stock totaling $14 million. In addition, the Utility paid cash dividends of $494 million on the Utility's common stock. Approximately $460 million in common stock dividends were paid to PG&E Corporation and the remaining amount was paid to PG&E Holdings LLC, a wholly owned subsidiary of the Utility that held approximately 7% of the Utility's common stock as of February 20, 2007.

In 2006, PG&E Corporation paid common stock dividends of $0.33 per share per quarter, a total of $489 million, including approximately $33 million of common stock dividends paid to Elm Power Corporation, a wholly owned subsidiary of PG&E Corporation that held approximately 7% of PG&E Corporation’s common stock as of February 20, 2007. On December 20, 2006, the Board of Directors declared a dividend of $0.33 per share, totaling approximately $123 million that was payable on January 15, 2007 to shareholders of record on December 29, 2006.

On February 21, 2007, the Board of Directors of the Utility declared a cash dividend on various series of its preferred stock payable on May 15, 2007, to shareholders of record on April 30, 2007.

PG&E Corporation and the Utility record common stock dividends declared to Reinvested Earnings.

Utility

Operating Activities

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

The Utility's cash flows from operating activities for 2006, 2005 and 2004 were as follows:

(in millions)	**2006**	**2005**	**2004**
Net income	$ 985	$ 934	$ 3,982
Adjustments to reconcile net income to net cash provided by operating activities:			

Depreciation, amortization, decommissioning and allowance for equity funds used during construction	1,755	1,697	1,494
Gain on sale of assets	(11)	-	-
Recognition of regulatory assets	-	-	(4,900)
Deferred income taxes and tax credits, net	(287)	(636)	2,580
Other deferred charges and noncurrent liabilities	116	21	(391)
Change in accounts receivable	128	(245)	(85)
Change in accrued taxes/income taxes receivable	28	(150)	52
Regulatory balancing accounts, net	329	254	(590)
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	(466)	491	718
Net cash provided by operating activities	$ 2,577	$ 2,366	$ 1,838

In 2006, net cash provided by operating activities increased by approximately $211 million from 2005. In addition to the increase from the increase in net income, the net cash provided by operating activities increased primarily due to the following factors:

- The Utility paid approximately $900 million in net tax payments in 2006 compared to approximately $1.4 billion in 2005.
- Deferred income taxes and tax credits decreased approximately $350 million, primarily due to an increased California franchise tax deduction, lower taxable supplier settlement income received and a deduction related to the payment of previously accrued litigation costs.
- Cash settlements with energy suppliers amounted to approximately $300 million in 2006 compared to only $160 million in 2005.
- Collections on balancing accounts increased by approximately $75 million in 2006, compared to 2005, since actual costs during 2006 were less than the forecasted costs used to set revenue requirements.

These increases were partially offset by the following:

- Approximately $290 million of pension contributions that were made during 2006. (See the “Regulatory Matters - Defined Benefit Pension Plan Contribution” below.)
- Approximately $295 million was paid in April 2006 to settle the majority of claims relating to alleged exposure to chromium at the Utility’s natural gas compressor stations.
- The Utility had approximately $185 million in additional costs primarily related to power and gas procurement that were unpaid at the end of 2005, compared to $60 million at the end of 2006, primarily due to higher gas prices during 2005.

In 2005, net cash provided by operating activities increased by approximately $528 million from 2004. This is mainly due to the following factors:

- The Utility received approximately $160 million in cash under settlements with third parties to resolve claims relating to the California 2000-2001 energy crisis with no similar settlements in 2004.
- The Utility had approximately $100 million in expenditures related to gas procurement and administrative and general costs that were unpaid at the end of 2005. In 2004, the Utility did not have similar unpaid expenditures.
- Collections on balancing accounts increased by approximately $800 million in 2005, compared to 2004, due to an increase in revenue requirements intended to recover 2004 undercollections.

The 2005 increase in net cash provided by operating activities also reflects the following:

- In 2004, the Utility paid approximately $1 billion of allowed creditor claims on the effective date of the Utility’s Chapter 11 plan of reorganization. Other than the $1.4 billion in tax payments described below, no similar amount was paid in 2005.

- In 2005, the Utility paid approximately $1.4 billion in tax payments compared to approximately $100 million in 2004. This increase in tax payments was primarily due to an increase in the taxable amount of payments the Utility received in 2005 under settlement agreements with energy suppliers to resolve claims relating to the California 2000-2001 energy crisis compared to 2004. In addition, 2005 tax payments increased due to a decrease in deductible tax depreciation compared to 2004.

- The Utility paid approximately $60 million more in 2005 compared to 2004 for gas inventory as a result of increased gas prices.

In October 2006, the CPUC approved the 10/20 Plus Winter Gas Savings Program, a conservation incentive that offers residential and commercial customers up to a 20 percent rebate for reducing their gas usage during January and February 2007. This initiative is expected to lower the Utility's cash inflows primarily during March through April 2007. However, the Utility expects to recover this cash throughout 2007. The Utility forecasts that this initiative will result in approximately $61 million in rebates to customers.

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 2006, 2005 and 2004. Year to year variances in cash used in investing activities depend primarily upon the amount and type of construction activities, which can be influenced by storms and other factors.

The Utility's cash flows from investing activities for 2006, 2005 and 2004 were as follows:

	2006	2005	2004
(in millions)			
Capital expenditures	$ (2,402)	$ (1,803)	$ (1,559)
Net proceeds from sale of assets	17	39	35
Decrease (increase) in restricted cash	115	434	(1,577)
Other investing activities, net	(156)	(29)	(178)
Net cash used by investing activities	$ (2,426)	$ (1,359)	$ (3,279)

Net cash used by investing activities increased by approximately $1 billion in 2006 compared to 2005, primarily due to an increase of approximately $600 million in capital expenditures. In addition, the Utility released more cash from escrow in 2005 upon settlement of disputed Chapter 11 generator claims than in 2006.

Net cash used by investing activities decreased by approximately $1.9 billion in 2005 compared to 2004 due primarily to a decrease in restricted cash. In 2004, the Utility's restricted cash of $2 billion consisted primarily of funds deposited and held in escrow to pay disputed Chapter 11 proceeding claims when resolved. Settlements during 2005 resulted in the release of these funds from escrow.

The Utility expects to maintain a high rate of infrastructure and information technology investment in its gas and electric system to keep pace with economic growth, to enhance the customer experience, and to mitigate the impacts of aging equipment on system performance. The Utility expects capital expenditures will total approximately $2.8 billion or greater in 2007. The higher level of capital investment is mostly due to the advanced metering infrastructure installation project, generation facility spending, replacing and expanding gas and electric distribution systems and improving the electric transmission infrastructure. (See "Capital Expenditures" below.)

Financing Activities

The Utility's cash flows from financing activities for 2006, 2005 and 2004 were as follows:

	2006	2005	2004
(in millions)			
Borrowings under accounts receivable facility and working capital facility	$ 350	$ 260	$ 300
Repayments under accounts receivable facility and working capital facility	(310)	(300)	-
Net issuance of commercial paper, net of discount of $2 million	458	-	-

Net proceeds from long-term debt issued	-	451	7,742
Net proceeds from energy recovery bonds issued	-	2,711	-
Long-term debt, matured, redeemed or repurchased	-	(1,554)	(8,402)
Rate reduction bonds matured	(290)	(290)	(290)
Energy recovery bonds matured	(316)	(140)	-
Preferred stock dividends paid	(14)	(16)	(90)
Common stock dividends paid	(460)	(445)	-
Preferred stock with mandatory redemption provisions redeemed	-	(122)	(15)
Preferred stock without mandatory redemption provisions redeemed	-	(37)	-
Common stock repurchased	-	(1,910)	-
Other financing activities	38	65	-
Net cash used by financing activities	$ (544)	$ (1,327)	$ (755)

In 2006, net cash used by financing activities decreased by approximately $783 million compared to 2005. This was mainly due to the following factors:

- The Utility had net issuances of $458 million in commercial paper, net of a $2 million discount, in 2006 with no similar amount in 2005.
- In 2005, the Utility repurchased $1.9 billion in common stock from PG&E Corporation. There were no common stock repurchases in 2006.
- The Utility received proceeds of $2.7 billion from the issuance of ERBs in 2005.
- In May 2005, the Utility borrowed $451 million from the California Infrastructure and Economic Development Bank, which was funded by the bank's issuance of Pollution Control Bonds Series A-G, with no similar borrowing in 2006.
- Approximately $316 million of ERBs matured in 2006 with only $140 million of maturities in 2005.
- The Utility borrowed $350 million from the accounts receivable facility during 2006, compared to $260 million in 2005.
- The Utility redeemed $122 million of preferred stock with no similar redemption in 2006.
- In 2005, the Utility redeemed $500 million and defeased $600 million of Floating Rate First Mortgage Bonds. The Utility also repaid $454 million under certain reimbursement obligations that the Utility entered into in April 2004, when its plan of reorganization became effective. There were no similar redemptions and repayments in 2006.

In 2005, net cash used by financing activities increased by approximately $572 million compared to 2004. This is mainly due to the following factors:

- Proceeds from long-term debt decreased by approximately $7.3 billion. In 2004, the Utility issued approximately $7.7 billion, net of issuance costs of $107 million, in long-term debt to fund its plan of reorganization. In 2005, only $451 million, net of issuance costs of $3 million, in long-term debt was incurred by the Utility related to the Pollution Control Bonds Series A-G.
- An aggregate of $2.7 billion in ERBs were issued in 2005 with no similar issuance in 2004.
- The Utility repaid $300 million in 2005 under its working capital facility, with no similar repayment in 2004.
- Approximately $140 million of ERBs matured in 2005 with no similar maturities in 2004.
- Long-term debt matured, redeemed or repurchased by the Utility decreased by approximately $6.8 billion in 2005. In 2004, repayments on long-term debt totaled approximately $8.4 billion, primarily to discharge pre-petition debt at the effective date of the plan of reorganization.
- In 2005, the Utility repurchased $1.9 billion in common stock from PG&E Corporation and paid $445 million in common stock dividends to PG&E Corporation and $31 million to PG&E Holdings LLC, a wholly owned subsidiary of the Utility.

- In 2005, the Utility redeemed $159 million of preferred stock compared to $15 million in 2004.

- Approximately $100 million in customer deposits (included in Other Financing Activities in the table above) was received in 2005 with no similar amount in 2004.

PG&E Corporation

As of December 31, 2006, PG&E Corporation had stand-alone cash and cash equivalents of approximately $386 million. PG&E Corporation's sources of funds are dividends from and share repurchases by the Utility, issuance of its common stock and external financing. In 2006, the Utility paid a total cash dividend of $460 million to PG&E Corporation. In 2005, the Utility paid a total cash dividend of $445 million to PG&E Corporation and repurchased $1.9 billion of its common stock from PG&E Corporation. 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 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 2006, 2005 and 2004 were as follows:

	2006	2005	2004
(in millions)			
Net income	$ 991	$ 917	$ 4,504
Gain on disposal of NEGT (net of income tax benefit of $13 million in 2005 and income tax expense of $374 million in 2004; See Note 7 of the Notes to the Consolidated Financial Statements for details)	-	(13)	(684)
Net income from continuing operations	991	904	3,820
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, decommissioning and allowance for equity funds used during construction	1,756	1,698	1,497
Loss from retirement of long-term debt	-	-	65
Tax benefit from employee stock plans	-	50	41
Gain on sale of assets	(11)	-	(19)
Recognition of regulatory asset, net of tax	-	-	(4,900)
Deferred income taxes and tax credits, net	(285)	(659)	2,607
Other deferred charges and noncurrent liabilities	151	33	(519)
Other changes in operating assets and liabilities	112	383	(736)
Net cash provided by operating activities	$ 2,714	$ 2,409	$ 1,856

In 2006, the net cash provided by operating activities increased by $305 million compared to 2005, primarily due to an increase in the Utility’s net cash provided by operating activities and tax refunds received by PG&E Corporation during the first and third quarters of 2006, with no similar refunds received during 2005.

In 2005, the net cash provided by operating activities increased by $553 million compared to 2004, primarily due to an increase in the Utility’s net cash provided by operating activities.

Investing Activities

PG&E Corporation, on a stand-alone basis, did not have any material investing activities in the years ended December 31, 2006, 2005 and 2004.

Financing Activities

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

PG&E Corporation's cash flows from financing activities for 2006, 2005 and 2004 were as follows:

(in millions)	2006	2005	2004
Borrowings under accounts receivable facility and working capital facility	$ 350	$ 260	$ 300
Repayments under accounts receivable facility and working capital facility	(310)	(300)	-
Net issuance of commercial paper, net of discount of $2 million	458	-	-
Net proceeds from issuance of long-term debt	-	451	7,742
Net proceeds from issuance of energy recovery bonds	-	2,711	-
Long-term debt matured, redeemed or repurchased	-	(1,556)	(9,054)
Rate reduction bonds matured	(290)	(290)	(290)
Energy recovery bonds matured	(316)	(140)	-
Preferred stock with mandatory redemption provisions redeemed	-	(122)	(15)
Preferred stock without mandatory redemption provisions redeemed	-	(37)	-
Common stock issued	131	243	162
Common stock repurchased	(114)	(2,188)	(378)
Common stock dividends paid	(456)	(334)	-
Other	3	32	(91)
Net cash used by financing activities	$ (544)	$ (1,270)	$ (1,624)

During 2006, PG&E Corporation's consolidated net cash used by financing activities decreased by approximately $726 million, compared to 2005, primarily due to the following factors, after consideration of the Utility's cash flows from financing activities:

- PG&E Corporation paid four quarterly common stock dividends in 2006, but made only three payments in 2005.
- In 2005, PG&E Corporation repurchased approximately $2.2 billion in common stock. There was no similar share repurchase in 2006 but PG&E Corporation paid certain additional payments of approximately $114 million to Goldman Sachs & Co., Inc. related to the prior year repurchase.

In 2005, PG&E Corporation's consolidated net cash used by financing activities decreased by approximately $354 million, compared to 2004, due to the following financing activities in addition to the Utility’s financing activities:

- In 2005, PG&E Corporation paid $334 million in common stock dividends with no similar payment in 2004.
- In 2005, PG&E Corporation issued $81 million more in common stock than in 2004.
- In 2005, PG&E Corporation repurchased $2.2 billion in common stock while repurchasing only $378 million in common stock in 2004.

PG&E Corporation expects its $280 million of Convertible Subordinated Notes will remain outstanding until maturity in 2010.

CONTRACTUAL COMMITMENTS

The following table provides information about the Utility's and PG&E Corporation's contractual obligations and commitments at December 31, 2006. PG&E Corporation and the Utility enter into contractual obligations in connection with business activities. These obligations primarily relate to financing arrangements (such as long-term debt, preferred stock and certain forms of regulatory financing), purchases of transportation capacity, natural gas and electricity to support customer demand and the purchase of fuel and transportation to support the Utility's generation activities.

Payment due by period

(in millions)	Total	Less than One year	1-3 years	3-5 years	More than 5 years
Contractual Commitments:					
Utility					
Purchase obligations:					
Power purchase agreements [1]:					
Qualifying facilities	$ 16,238	$ 1,672	$ 3,331	$ 2,693	$ 8,542
Irrigation district and water agencies	325	80	70	61	114
Renewable contracts	4,356	166	498	637	3,055
Other power purchase agreements	919	251	421	218	29
Natural gas supply and transportation	1,138	954	176	8	-
Nuclear fuel	539	135	152	101	151
Preferred dividends and redemption requirements [2]	42	8	17	17	-
Employee benefits:					
Pension [3]	528	176	352	-	-
Other commitments [4]	142	123	19	-	-
Advanced metering infrastructure	17	17	-	-	-
Operating leases	109	20	32	23	34
Long-term debt [5]:					
Fixed rate obligations	11,514	297	1,188	1,045	8,984
Variable rate obligations	1,738	40	75	688	935
Other long-term liabilities reflected on the Utility's balance sheet under GAAP:					
Rate reduction bonds [6]	302	302	-	-	-
Energy recovery bonds [7]	2,612	435	870	891	416
Capital lease obligations [8]	553	50	100	100	303
PG&E Corporation					
Long-term debt [5]:					
Convertible subordinated notes	372	27	53	292	-
Operating leases	13	3	5	5	-
Canadian natural gas pipeline firm transportation contracts [9]	128	2	18	16	92

[1] This table does not include DWR allocated contracts because the DWR is currently legally and financially responsible for these contracts and payments.

[2] Preferred dividend and redemption requirement estimates beyond 5 years do not include nonredeemable preferred stock dividend payments as these continue in perpetuity.

[3] PG&E Corporation's and the Utility's funding policy is to contribute tax deductible amounts, consistent with applicable regulatory decisions, sufficient to meet minimum funding requirements. Contribution estimates after 2007 will be driven by CPUC decisions. See further discussion under “Regulatory Matters.”

[4] Includes commitments for capital infusion agreements for limited partnership interests in the aggregate amount of approximately $4 million, load-control and self-generation CPUC initiatives in the aggregate amount of approximately $123 million and contracts for local and long-distance telecommunications in the aggregate amount of approximately $15 million.

[5] Includes interest payments over the terms of the debt. See Note 4 of the Notes to the Consolidated Financial Statements for further discussion.

[6] Includes interest payments over the terms of the bonds. See Note 5 of the Notes to the Consolidated Financial Statements for further discussion of RRBs.

[7] Includes interest payments over the terms of the bonds. See Note 6 of the Notes to the Consolidated Financial Statements for further discussion of ERBs.

(8) See Note 17 of the Notes to the Consolidated Financial Statements for further discussion of the capital lease obligations.
(9) See Note 17 of the Notes to the Consolidated Financial Statements for further discussion of the PG&E Corporation's natural gas pipeline firm transportation contracts.

The Utility's contractual commitments include power purchase agreements (including agreements with qualifying facility co-generators, or QFs, irrigation districts and water agencies and renewable energy providers), natural gas supply and transportation agreements, nuclear fuel agreements, operating leases and other commitments that are discussed in Note 17 of the Notes to the Consolidated Financial Statements.

The contractual commitments table above excludes potential commitments associated with the conversion of existing overhead electric facilities to underground electric facilities. At December 31, 2006, the Utility was committed to spending approximately $211 million for these conversions. These funds are conditionally committed depending on the timing of the work, including the schedules of the respective cities, counties and telephone utilities involved. The Utility expects to spend approximately $50 million to $60 million each year in connection with these projects. Consistent with past practice, the Utility expects that these capital expenditures will be included in rate base as each individual project is completed and recoverable in rates charged to customers.

CAPITAL EXPENDITURES

The Utility's investment in plant and equipment totaled approximately $2.4 billion in 2006, $1.9 billion in 2005, and $1.6 billion in 2004. The Utility expects capital expenditures will total approximately $2.8 billion or greater in 2007. The Utility's weighted-average rate base in 2006 was $15.9 billion. Based on the estimated capital expenditures for 2007, the Utility projects a weighted-average rate base for 2007 of approximately $17.3 billion. Over the next five years, the Utility expects, subject to regulatory approval, to replace aging infrastructure and otherwise invest in plant and equipment to accommodate anticipated electricity and natural gas load growth and invest in the projects listed below.

Advanced Metering Infrastructure

In July 2006, the CPUC issued a decision approving the Utility's application to install an advanced metering infrastructure, known as the SmartMeter ™ system, for virtually all of the Utility's electric and gas customers. This infrastructure enables the Utility 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 began installation of the infrastructure in 2006 and expects to complete the installation throughout its service territory by the end of 2011.

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

The CPUC authorized the Utility to recover the $1.74 billion estimated SmartMeter ™ project cost, including an estimated capital cost of $1.4 billion. The $1.74 billion amount includes $1.68 billion for project costs and approximately $54.8 million for costs to market the SmartMeter ™ technology . In addition, the Utility can recover in rates 90% of up to $100 million in costs that exceed $1.68 billion without a reasonableness review by the CPUC. The remaining 10% will not be recoverable in rates. If additional costs exceed the $100 million threshold, the Utility may request recovery of the additional costs, subject to a reasonableness review.

PG&E Corporation and the Utility cannot predict whether or to what extent the anticipated benefits and cost savings of the advanced metering infrastructure project will be realized.

Diablo Canyon Steam Generator Replacement Project

In November 2005, the CPUC approved the Utility's replacement of the steam generators at the two nuclear operating units at Diablo Canyon, one in 2008 and one in 2009. The estimated cost of the steam generation replacement project, or SGRP, is $642 million, of which $165 million had been spent as of December 31, 2006, including progress payments on contracts for the eight steam generators the Utility has ordered.

To implement the SGRP, the Utility has obtained two coastal development permits from the California Coastal Commission to build temporary structures at Diablo Canyon to house the new generators as they are prepared for installation and for certain offloading activities. The Utility also has obtained a conditional use permit from San Luis Obispo County to store the old generators

on site at Diablo Canyon. On January 10, 2007, the Coastal Law Enforcement Action Network filed a lawsuit in the Superior Court for the County of San Francisco against both the California Coastal Commission and the Utility alleging that the commission violated the California Coastal Act, the California Environmental Quality Act, and the San Luis Obispo Certified Local Coastal Program when it approved the permits without requiring the Utility to commit to undertake certain proposed or otherwise feasible mitigation measures. The complaint requests that the court (1) find that the approval of the permits was "illegal and invalid," (2) order the commission to set aside and vacate its approval, and (3) issue a permanent injunction to prohibit the Utility from engaging in any activity authorized by the permits until the commission complies with the judgment that the court may render. The complaint does not seek a temporary restraining order against the Utility. PG&E Corporation and the Utility believe that the permits were legally and validly approved and issued.

If the Utility's SGRP is delayed, the Utility could incur additional costs to operate and maintain the old steam generators until they can be replaced and to delay and extend project completion dates. If the Utility is not able to complete the SGRP, the Utility would be required to cease operations at Diablo Canyon and procure power from other sources when the generators are no longer operable in conformance with operating standards. The Utility would also have to pay for all work done in connection with the design and fabrication of the eight steam generators and a pro-rated profit up to the time the performance under the contracts is completed or the contracts are terminated.

New Generation Facilities

During 2006, the CPUC approved three contracts that provide for the construction of generation facilities to be owned and operated by the Utility:

- *Gateway Generating Station.* In June 2006, the CPUC authorized the Utility to acquire the equipment, permits, and contracts related to a partially completed 530-megawatt, or MW, power plant in Antioch, California, referred to as the Gateway Generating Station, or Gateway. The Utility completed the acquisition in November 2006. The CPUC authorized the Utility to recover approximately $295 million in capital costs to complete the construction of the facility as well as costs for its operation. On February 15, 2007, the CPUC approved the Utility's request to recover an additional approximately $75 million necessary to convert the plant from fresh water cooling to dry cooling in order to reduce the environmental impact of the facility and as a result of changes to Gateway's environmental permits. The Utility also has filed a request with the California Energy Commission, or CEC, to amend the facility's current permit to authorize the plant to be converted from fresh water cooling to dry cooling. The Utility expects that the CEC will issue a decision in the second quarter of 2007. Subject to obtaining the permit amendment from the CEC, meeting construction schedules, operational performance requirements and other conditions, t he Utility estimates that it will complete construction of the Gateway facility and commence operations in 2009 at an estimated cost of approximately $370 million including expenditures related to the conversion to dry cooling.

- *Colusa Power Plant.* In November 2006, the CPUC approved an agreement f or the development and construction of a 657-MW power plant to be located in Colusa County, California. The CPUC adopted an initial capital cost for the Colusa project that is equal to the sum of the fixed contract costs plus the Utility's estimated owner's costs and a contingency amount to account for the risk and uncertainty in the estimation of owner's costs. (Owner's costs include the Utility's expenses for legal, engineering, and consulting services as well as the costs for internal personnel and overhead related to the project.) The CPUC also authorized the Utility to adjust the initial capital cost for the Colusa project to reflect any actual incentive payments made to, or liquidated damages received from, the contractors through notification to the CPUC but without a reasonableness review . Subject to obtaining required permits, meeting construction schedules, operational performance requirements and other conditions, it is anticipated that the Colusa project will commence operations in 2010 at an estimated cost of approximately $673 million.

- *Humboldt Bay Power Plant.* In November 2006, the CPUC also approved an agreement for the construction of a 163-MW power plant to re-power the Utility's existing power plant at Humboldt Bay, which is at the end of its useful life. The CPUC adopted an initial capital cost of the Humboldt Bay project equal to the sum of the fixed contract costs plus the Utility's estimated owner's costs, but limited the contingency amount for owner's costs to five percent of the fixed contract cost and estimated owner's costs. Subject to obtaining required permits, meeting construction schedules, operational performance requirements and other conditions, it is anticipated that the Humboldt Bay project will commence operations in 2009 at an estimated cost of approximately $239 million.

The CPUC authorized the Utility to adjust the initial capital costs for the Colusa and Humboldt Bay projects to reflect any actual incentive payments made to, or liquidated damages received from, the contractors through notification to the CPUC but without a reasonableness review. The forecasted initial capital cost of the Colusa and Humboldt Bay projects will be trued-up in the Utility's next GRC following the commencement of operations of each plant to reflect actual initial capital costs. The true-up will reflect 50 percent of any actual cost savings for the Colusa project and all cost savings, if any, for the Humboldt Bay project. The Utility is authorized to seek recovery of additional capital costs incurred in connection with the Colusa and Humboldt Bay projects that are

attributable to operational enhancements, but the request will be subject to the CPUC's review. Although the Utility is permitted to seek recovery of additional capital costs incurred in connection with the Humboldt Bay project subject to a reasonableness review, the Utility is not permitted to seek recovery of any other additional capital costs incurred in connection with the Colusa project.

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 enable PG&E Corporation and the Utility to obtain financing or execute commercial transactions on more favorable terms. For further information related to letter of credit agreements, the credit facilities, and PG&E Corporation's guarantee related to certain NEGT indemnity obligations, see Notes 4 and 17 of the Notes to the Consolidated Financial Statements.

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. The Utility is exposed to a concentration of credit risk associated with receivables from the sale of natural gas and electricity to residential and small commercial customers in northern and central California. This credit risk exposure is mitigated by requiring deposits from new customers and from those customers whose past payment practices are below standard. A material loss associated with the regional concentration of retail receivables is not considered likely.

Additionally, the Utility has a concentration of credit risk associated with its wholesale customers and counterparties mainly in the energy industry, including other California investor-owned electric utilities, municipal utilities, energy trading companies, financial institutions, and oil and natural gas production companies located in the United States and Canada. This concentration of counterparties may impact the Utility's overall exposure to credit risk because counterparties may be similarly affected by economic or regulatory changes, or other changes in conditions. If a counterparty failed to perform on their contractual obligation to deliver electricity, then the Utility may find it necessary to procure electricity at current market prices, which may be higher than those prices contained in the contract. Credit losses attributable to receivables and electrical and gas procurement activities from both retail and wholesale customers and counterparties are expected to be recoverable from customers through rates and are not expected to have a material impact on earnings.

The Utility manages credit risk associated with its wholesale customers and counterparties by assigning credit limits based on evaluations of their financial condition, net worth, credit rating, and other credit criteria as deemed appropriate. Credit limits and credit quality are monitored periodically and a detailed credit analysis is performed at least annually. 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 schedule below summarizes the Utility's net credit risk exposure to its wholesale customers and counterparties, as well as the Utility's credit risk exposure to its wholesale customers or counterparties with a greater than 10% net credit exposure, at December 31, 2006 and December 31, 2005:

(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%
December 31, 2006	$ 255	$ 87	$ 168	2	$ 113
December 31, 2005	$ 447	$ 105	$ 342	3	$ 165

[1] Gross credit exposure equals mark-to-market value on financially settled contracts, notes receivable and net receivables (payables) where netting is contractually allowed. Gross and net credit exposure amounts reported above do not include adjustments for time value or liquidity. The Utility's gross credit exposure includes wholesale activity only.

(2) Net credit exposure is the gross credit exposure minus credit collateral (cash deposits and letters of credit). For purposes of this table, parental guarantees are not included as part of the calculation.

CONTINGENCIES

PG&E Corporation and the Utility have significant contingencies that are discussed in Note 17 of the Notes to the Consolidated Financial Statements.

REGULATORY MATTERS

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

2007 General Rate Case

On February 13, 2007, a proposed decision was issued by an administrative law judge, or ALJ, presiding over the Utility's 2007 GRC pending at the CPUC. On the same day, an alternate proposed decision was issued by the assigned CPUC Commissioner in the case. The ALJ's proposed decision recommends modifications to the proposed settlement agreement reached in August 2006 among the Utility, the CPUC's Division of Ratepayer Advocates, or DRA, and other parties, to resolve the issues raised by these parties and all revenue requirement-related issues raised in the 2007 GRC. The alternate proposed decision issued by the assigned Commissioner recommends that the proposed settlement agreement be approved.

Both the proposed decision and the alternate proposed decision accept the settlement agreement's proposal to set the Utility's GRC revenue requirements for a four-year period, 2007-2010. Under this proposal, the Utility's next GRC would be effective January 1, 2011. On October 19, 2006, the CPUC approved the Utility's request to make the revenue requirements ultimately adopted by the CPUC effective on January 1, 2007.

The settlement agreement proposes that the Utility's electric and gas service revenue requirements effective January 1, 2007 be set at approximately $2.9 billion for electric distribution, approximately $1 billion for gas distribution, and $1 billion for electric generation operations, for a total of approximately $4.9 billion. The revenue requirement amounts set forth in the settlement agreement reflect an increase of $222 million in the Utility's electric distribution revenues, an increase of $20.5 million in gas distribution revenues, and a decrease of $29.8 million in generation operation revenues, for an overall increase of $212.7 million (or 4.5%), over the 2006 authorized amounts. Under the settlement agreement, the Utility's revenue requirements are $181 million less than the amount requested in the Utility's original GRC application. Of this amount, approximately $95 million relates to depreciation expense, approximately $29 million relates to return and taxes associated with rate base, approximately $21 million relates to operating and maintenance expenses and customer service expenses, and approximately $36 million relates to administrative and general expenses, payroll taxes, and other miscellaneous expenses.

The settlement agreement also provides for annual attrition adjustments to authorized revenues of $125 million in each of 2008, 2009, and 2010 and an additional adjustment of $35 million in 2009 for the cost of a second refueling outage at Diablo Canyon. The attrition adjustment to authorized revenues for 2010 would be $125 million, less the one-time additional amount of $35 million from 2009, for a net increase of $90 million in 2010. The attrition adjustments discussed above incorporate some estimated benefits for the Utility's customers of cost savings attributable to the Utility's implementation of initiatives to achieve operating and cost efficiencies in 2008, 2009 and 2010. If the actual cost savings exceed the estimated benefits, such benefits would accrue to shareholders. Conversely, if these cost savings are not realized, earnings available for shareholders would be reduced.

The ALJ's proposed decision would modify the revenue requirements proposed in the settlement agreement in a number of areas, including hydroelectric operations, rate base and the treatment of certain tax issues. Instead of the $213 million total revenue requirement increase over 2006 authorized revenues proposed in the settlement agreement, the ALJ's proposed decision would result in a total revenue requirement increase of approximately $170 million over 2006 authorized revenues ($43 million less than the amount proposed in the settlement agreement). Both the ALJ's proposed decision and the alternate proposed decision would accept the attrition adjustments proposed in the settlement agreement.

The following table sets forth the amount of the changes to 2006 authorized revenue requirements, by category, that would result from the revenue requirements recommended in the proposed decision and in the alternate proposed decision and the differences between the resulting revenue requirement change:

(in millions)	Proposed Decision (Recommending Modification to Settlement Amounts)	Alternate Proposed Decision (Recommending Settlement Amounts)	Difference Between Recommended Amounts
Electric distribution	$ 199	$ 222	$ (23)
Gas distribution	9	21	(12)
Electric generation	(38)	(30)	(8)
Total revenue requirement increase (decrease) for 2007:	$ 170	$ 213	$ (43)

The CPUC rules of procedure generally require that a proposed decision have been issued at least 30 days before the CPUC can vote on the decision. The next scheduled meeting at which the CPUC could issue a final decision in the 2007 GRC will be held on March 15, 2007.

PG&E Corporation and the Utility are unable to predict when the CPUC will issue a final decision or whether the settlement agreement will be approved.

Electricity Generation Resources

Each California investor-owned electric utility is responsible to procure electricity to meet customer demand, plus applicable reserve margins, not satisfied from that utility's own generation facilities and existing electricity contracts. Each utility must submit a long-term procurement plan covering a ten year period to the CPUC for approval. California legislation allows the California investor-owned utilities to recover their wholesale electricity procurement costs incurred in accordance with their CPUC-approved procurement plans. The Utility's forecasted costs under power purchase agreements and fuel costs are reviewed annually and recovered through the Energy Resource Recovery Account, or the ERRA, a balancing account designed to track and allow recovery of the difference between the authorized revenue requirement and actual costs incurred under the Utility's CPUC-authorized procurement plans. 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. In addition, the CPUC will adjust retail electricity rates or order refunds, as appropriate, when the forecast aggregate over-collections or under-collections exceed 5% of a utility's prior year electricity procurement revenues (excluding amounts collected for the DWR contracts) for the length of a utility's resource commitment or 10 years, whichever is longer. The Chapter 11 Settlement Agreement also provides that the Utility will recover its reasonable costs of providing utility service, including power procurement costs.

The authorized revenue requirements for capital costs and non-fuel operating and maintenance costs for Utility-owned generation are addressed in the Utility's GRC. If the CPUC approves the 2007 GRC settlement agreement, the Utility's next GRC will not occur until 2011.

Cost Recovery for New Generation Resources

The CPUC decided that the utilities should be allowed to recover any above market or stranded costs of new generation resources from departing customers, as well as from their retail or "bundled" electricity customers, through the imposition of a non-bypassable charge. For a utility-owned generation facility, the duration of the stranded cost recovery period would be 10 years beginning with commercial operations, and for a power purchase agreement, the duration would be 10 years or the term of the contract, whichever is less. At the end of this 10-year period, the Utility will still be able to collect any stranded costs from its current full-service customers, but no longer be able to charge departing customers for those costs. Contracts for renewable energy sources, however, are eligible for stranded cost recovery over the entire life of the contract. The utilities are allowed to justify a stranded cost recovery period longer than 10 years on a case-by-case basis. The implementation of the non-bypassable charge is being addressed in the CPUC's 2006 long-term procurement plan proceeding discussed below.

In July 2006, the CPUC issued a decision adopting a transitional policy to foster investment in new generation and directing the California investor-owned utilities to proceed expeditiously to procure new generation on behalf of all benefiting customers in an investor-owned utility's service territory. Under this transitional policy, for new generation purchased from third parties under power purchase agreements, the utilities may elect to allocate the net capacity costs (i.e., contract price less energy revenues) to all "benefiting customers" in the utilities' service territory, including existing direct access customers (i.e., former customers who choose to buy energy from an alternate service provider other than the regulated utilities) and customers of community choice aggregators

(i.e., cities and counties who purchase and sell electricity for their local residents and businesses) , rather than recovering stranded costs only from their bundled and departing customers.

If a utility elects to use the net capacity cost allocation method, the net capacity costs would be allocated for the term of the contract or 10 years, whichever is less, starting on the date the new generation unit comes on line. Under this allocation mechanism, the right to receive energy under the contract is auctioned off to maximize the energy revenue and minimize the net capacity costs that would be subject to allocation. If no bids are accepted for the energy rights, the utility would retain the rights to the energy and would value it at spot market prices for the purposes of determining the net capacity costs to be allocated until the next periodic auction. Specific implementation details for the energy rights auction are also being addressed in the 2006 long-term procurement plan proceeding discussed below, and the CPUC noted that the evolution of a new market-based system may change the mechanics of this cost allocation method.

2006 Long-Term Procurement Plan

In December 2006, the Utility submitted its 2006 long-term procurement plan to the CPUC for approval of its 2007-2016 electric energy and electric fuel procurement plans. A decision is expected by the end of 2007. The plan forecasts demand for up to an additional 2,300 MW of new dispatchable and operationally flexible capacity starting 2011. The Utility's proposed long-term plan is designed to provide reliable service, promote environmentally preferred resources and manage customer costs. The Utility is proposing cost recovery and reasonableness review protection and requests approval for:

- short, medium and long-term procurement implementation authority;
- a nuclear fuel supply plan;
- a gas supply plan and asset plan; and
- an electric and gas price risk hedging plan.

The Utility anticipates that after CPUC approval of its procurement plan, the Utility would be expected to complete a competitive request for offer from providers of all potential sources of new generation (e.g., conventional or renewable resources to be provided under turnkey developments, buyouts, or power purchase agreements) to meet the Utility's projected need for electricity resources. PG&E Corporation and the Utility cannot predict whether the CPUC will approve the Utility's proposed plan or whether any of the new generation resources commitments will be Utility-owned generation projects.

Resource Adequacy

California investor-owned electric utilities (and most other entities that serve electricity customers under the jurisdiction of the CPUC) are required to meet certain capacity planning requirements and demonstrate they have met those targets through annual and monthly compliance filings. There is a general, or system, requirement to achieve an electricity planning reserve margin of 15% to 17% above forecasted peak electricity usage or "load." Within that general requirement, a certain portion must be met within predefined local areas (i.e., areas on the system that are transmission constrained). In December 2006, the CPUC outlined additional issues to be considered in future phases of the CPUC's r esource adequacy proceeding which establishes planning requirements. Issues in the next phase include the possibility of increasing the electricity planning reserve margin requirement and instituting longer-term requirements.

If the CPUC determines that a utility or other load serving entity has not met its requirement in a particular year, the CPUC can impose penalties in an amount determined by the CPUC. The penalty for failure to procure sufficient system resource adequacy capacity is equal to three times the cost of securing new resources, which the CPUC set at $120 per kilowatt-year, or kW-year. The penalty for failure to meet local resource adequacy requirements is equal to $40 per kW-year. In addition to penalties, entities that fail to meet resource adequacy requirements may be assessed the cost of backstop procurement by the CAISO to fulfill their resource adequacy target levels. The Utility's proposed 2007-2016 long-term procurement plan forecasts that the Utility will be able to meet future resource adequacy requirements.

Qualifying Facility Power Purchase Agreements

The CPUC is considering various policy and pricing issues related to power purchased from QFs in rulemaking proceedings. During 2006, the Utility and the Independent Energy Producers, or IEP, on behalf of certain QFs, entered into, and the CPUC approved, a settlement agreement and a QF contract amendment to resolve these issues for the settling parties. As of December 31, 2006, the CPUC approved amendments for 122 QFs projects which reduces the Utility's energy payments and establishes a new five

year fixed pricing option for QFs that do not use natural gas as their fuel source. The IEP settlement agreement also resolves certain energy crisis claims by the Utility against a subset of the settling QFs that are pending in a different CPUC proceeding. Such claims remain unresolved for those QFs which did not participate in the settlement.

As described in Note 17 in the Notes to the Consolidated Financial Statements, the obligations under some of the amended QF contracts qualify for capital lease accounting.

Renewable Energy Contracts

California law, as amended in September 2006, by the enactment of Senate Bill 107, established the renewables portfolio standard, or RPS program. The RPS program requires each California retail seller of electricity, except municipal utilities (other than community choice aggregators), to increase its purchases of eligible renewable energy (such as biomass, small hydro, wind, solar, and geothermal energy) by at least 1% of its retail sales per year so that the amount of electricity purchased from eligible renewable resources equals at least 20% of its total retail sales by the end of 2010. “Flexible compliance” rules, under the RPS program, allow a retail seller to satisfy and defer (for up to three years) its current year RPS requirements by signing contracts with renewable energy suppliers for future deliveries of renewable power. These rules also allow the CPUC to excuse noncompliance with the RPS targets if a retail seller is able to demonstrate good cause. Senate Bill 107, which became effective January 1, 2007, continues to permit use of flexible compliance rules and directs the CPUC to adopt flexible compliance rules that will apply to all years, including years before and after a retail seller meets the 20% RPS target. Senate Bill 107 also excuses retail sellers from the 20% RPS requirement if there is insufficient transmission capacity to deliver that power to California end-users.

In October 2006, the CPUC adopted rules for reporting and determining whether the RPS requirements have been met. The CPUC’s decision addresses existing flexible compliance rules applicable to procurement through 2009, allowing an excused 2009 deficit to be fulfilled by the end of 2012. The CPUC also stated that a retail seller that has reached the 20% RPS target in a given year, but that had not yet fulfilled deferred compliance from prior years, must continue to increase its procurement in subsequent years until the deferred compliance is satisfied or is otherwise excused by the CPUC. The October 2006 order, which was issued prior to the effective date of Senate Bill 107, reiterated prior CPUC decisions in stating that the 20% RPS target must be met with actual eligible energy deliveries in 2010, but acknowledged that Senate Bill 107 changed flexible compliance requirements and further stated that that the CPUC would address the application of flexible compliance rules to 2010 and beyond in a future decision after the statute’s effective date.

Currently, power from eligible renewable energy resources comprises approximately 12% of the Utility’s retail sales. The Utility expects to comply with its 2004, 2005, 2006 and 2007 annual RPS targets . Although the Utility expects it will achieve the 20% target using the flexible compliance rules by 2010, actual deliveries of renewable power may not comprise 20% of its bundled retail sales by 2010 due to such factors as the time required for the construction of new generation facilities and/or needed transmission capacity. Failure to satisfy the RPS targets may result in a penalty of five cents per kilowatt hour with an annual penalty cap of $25 million. The exact amount of any penalty and conditions under which it would be applied is subject to the CPUC’s review of the circumstances for under-delivery. With the flexible compliance rules that have been adopted to date by the CPUC, the Utility does not expect to incur penalties in the forecast timeframe of 2007 to 2009. The Utility anticipates, given the clear language of Senate Bill 107 requiring that flexible compliance rules “shall apply to all years, including years before and after” a retail seller reaches the 20% target, that the CPUC will extend existing flexible compliance rules to 2010 and future years, and on that basis do not expect to incur penalties in 2010. However, an Assembly Bill has been introduced in the California Legislature for consideration in 2007 to increase the RPS requirement to 33% of total retail sales by the end of 2020. The Utility is unable to predict whether this bill will be passed or whether the higher RPS target could be met.

The CPUC has adopted a procedure to enable the utilities to recover the cost of electric transmission and distribution facilities necessary to interconnect renewable energy resources if those costs cannot be recovered in federally approved rates. In 2007, the Utility will continue to plan for and begin implementation of various transmission projects to improve access to renewable energy resources, among other purposes.

FERC Transmission Rate Case

The Utility's electric transmission revenues and wholesale and retail transmission rates are subject to authorization by the FERC. In August 2006, the Utility filed an application with the FERC requesting an annual transmission revenue requirement of approximately $719 million, effective October 1, 2006. The proposed rates represent an increase of approximately $113 million over current authorized revenue requirements. In September 2006, the FERC issued an order accepting the Utility’s rate application, suspending the requested rate changes for five months to become effective March 1, 2007, subject to refund. The FERC also ordered the Utility and interveners in the case to engage in settlement discussions to be supervised by a settlement judge.

On February 15, 2007, the Utility submitted an offer of settlement reached by the parties and requested that the settlement judge recommend that the FERC approve the settlement. The settlement proposes to set the Utility's transmission retail revenue requirements at $674 million, an increase of approximately $68 million over current authorized revenue requirements. If the FERC approves the proposed settlement, the revenue requirement changes will be deemed to have been effective as of March 1, 2007. The Utility would refund any over-collected amounts, with interest, to customers.

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

Natural Gas Transmission and Storage Rate Case

The Utility's gas transmission and storage services, rates and market structure are subject to authorization by the CPUC. In December 2004, the CPUC approved the Gas Accord III, which set rates, terms, and conditions through December 31, 2007, for transmission services, and through March 31, 2008, for storage services.

The Utility is obligated to file a new rate case proposing gas transmission and storage rates and terms and conditions of service, for the period commencing January 1, 2008. The Utility currently is scheduled to submit that filing on March 15, 2007. In the event the CPUC does not issue a final decision approving new rates effective January 1, 2008, the Gas Accord III provides that the rates and terms and conditions of service in effect as of December 31, 2007, will remain in effect, with an automatic 2% escalation in the rates as of January 1, 2008.

Under the Gas Accord III, the costs associated with the Utility's local gas transportation and gas storage assets that are used for service to core customers are recovered through balancing account mechanisms that adjust for the difference between actual usage and forecast usage. In addition, approximately 65% of the costs associated with the Utility's backbone gas transmission system that is used to serve core customers are recovered through fixed charges. The remaining 35% of these costs are recoverable through volumetric charges. Revenues from these charges vary depending on the level of throughput volume. The costs that are recoverable through balancing accounts or fixed reservation charges account for approximately 45% of the Utility's total revenue requirement for gas transmission and storage. The remainder of the Utility's gas transmission and storage costs are recovered from core customers through volumetric charges and from noncore customers under firm or interruptible transmission or storage contracts. The Utility's recovery of this portion of its costs depends on the level of throughput volume, gas prices, and the extent to which noncore customers contract for firm services.

Spent Nuclear Fuel Storage Proceedings

Under the Nuclear Waste Policy Act of 1982, the Department of Energy, or the DOE, is responsible for the transportation and permanent storage and disposal of spent nuclear fuel and high-level radioactive waste. The Utility has contracted with the DOE to provide for the disposal of these materials from Diablo Canyon. Under the contract, if the DOE completes a storage facility by 2010, the earliest that Diablo Canyon's spent fuel would be accepted for storage or disposal is thought to be 2018. Under current operating procedures, the Utility believes that the existing spent fuel pools (which include newly constructed temporary storage racks) have sufficient capacity to enable the Utility to operate Diablo Canyon until approximately 2010 for Unit 1 and 2011 for Unit 2. After receiving a permit from the NRC in March 2004, the Utility began building an on-site dry cask storage facility to store spent fuel through at least 2024. T he Utility estimates it could complete the dry cask storage project in 2008. The NRC's March 2004 decision, however, was appealed by various parties, and the U.S. Court of Appeals for the Ninth Circuit, or Ninth Circuit, issued a decision in 2006 that requires the NRC to consider the environmental consequences of a potential terrorist attack at Diablo Canyon as part of the NRC's supplemental assessment of the dry cask storage permit. The Utility may incur significant additional expenditures if the NRC decides that the Utility must change the design and construction of the dry cask storage facility. If the Utility is unable to complete the dry cask storage facility, or if construction is delayed beyond 2010, and if the Utility is otherwise unable to increase its on-site storage capacity, it is possible that the operation of Diablo Canyon may have to be curtailed or halted as early as 2010 with respect to Unit 1 and 2011 with respect to Unit 2 and until such time as additional spent fuel can be safely stored.

As a result of the DOE's failure to develop a permanent storage facility, the Utility has been required to incur substantial costs for planning and developing on-site storage options for spent nuclear fuel as described above at Diablo Canyon as well as at the retired nuclear facility at Humboldt Bay, or Humboldt Bay Unit 3. The Utility is seeking to recover these costs from the DOE on the basis that the DOE has breached its contractual obligation to move used nuclear fuel from Diablo Canyon and Humboldt Bay Unit 3 to a national repository beginning in 1998. Any amounts recovered from the DOE will be credited to customers. In October 2006, the U.S. Court of Federal Claims issued a decision awarding approximately $42.8 million of the $92 million incurred by the Utility through 2004. The Utility will seek recovery of costs incurred after 2004 in future lawsuits against the DOE. In January 2007, the Utility filed a notice of appeal of the U.S. Court of Federal Claims' decision in the U.S. Court of Appeals for the Federal Circuit seeking to increase the amount of the award and challenging the court's finding the Utility would have had to incur some of the costs for the onsite storage facilities even if the DOE had complied with the contract. If the court's decision is not overturned or modified

on appeal, it is likely that the Utility will be unable to recover all of its future costs for onsite storage facilities from the DOE. However, reasonably incurred costs related to the onsite storage facilities are, in the case of Diablo Canyon, recoverable through rates and, in the case of Humboldt Bay Unit 3, recoverable through its decommissioning trust fund.

PG&E Corporation and the Utility are unable to predict the outcome of this appeal or the amount of any additional awards the Utility may receive.

Defined Benefit Pension Plan Contribution

In June 2006, the CPUC approved the Utility's recovery of revenue requirements associated with annual contributions to fund the Utility's pension plan from 2006 to 2009. On a projected basis, these contributions are expected to bring the pension plan trust to fully funded status as of January 1, 2010 .

I n July 2006, the Utility made the 2006 authorized net pension contribution of $250 million funded by the authorized $155 million revenue requirement attributable to the Utility's distribution and generation operations, or GRC lines of business. Approximately $20 million of the $250 million contribution relates to revenue requirements for gas transmission and storage, electric transmission, and nuclear decommissioning, which have been or will be addressed in other CPUC or FERC proceedings. The remaining 2006 contribution amount will be capitalized and recovered in future periods. Additional pension contributions of $40 million associated with the 1994 voluntary retirement incentive, $3 million for PG&E Corporation participants, and $1 million for interest on the net pension contributions were also made during the year ended December 31, 2006.

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

Delayed Billing Investigation

In February 2005, the CPUC issued a ruling opening an investigation into the Utility's billing and collection practices and credit policies. The investigation was initiated at the request of The Utility Reform Network, or TURN, after the CPUC's January 2005 decision that characterized the definition of "billing error" in a revised Utility tariff to include delayed bills and Utility-caused estimated bills as being consistent with "existing CPUC policy, tariffs, and requirements." The Utility contended that prior to the CPUC's January 2005 decision, "billing error" under the Utility's former tariffs did not encompass delayed bills or Utility-caused estimated bills. The Utility petitioned the California Court of Appeals to review the CPUC's decision denying rehearing of its January 2005 decision. In December 2006, the Court of Appeals summarily rejected the Utility's petition; the Utility did not appeal that rejection to the California Supreme Court.

The CPUC's Consumer Protection and Safety Division, or CPSD, and TURN have submitted their reports to the CPUC concluding that the Utility violated applicable tariffs related to delayed and estimated bills and recommended refunds in the current amounts of approximately $54 million and $36 million, respectively, plus interest at the three-month commercial paper interest rate . The two refunds are not additive. The CPSD also recommended that the Utility pay fines of $6.75 million, while TURN recommends fines in the form of a $1 million contribution to REACH (Relief for Energy Assistance through Community Help). Both the CPSD and TURN recommend that refunds and fines be funded by shareholders.

The Utility responded that its tariff interpretation was in good faith, and was repeatedly supported by Commission staff. It argued that the CPUC should exercise its discretion not to order refunds, and that any ordered refunds should be treated in accordance with adopted ratemaking, under which the significant majority of the costs of any refunds would be reflected in future rates borne by the Utility's general body of customers. It argued that its behavior does not warrant fines or penalties. On February 15, 2007, the CPUC extended the date by which it must issue a final decision in this investigative matter to August 26, 2007.

On February 20, 2007, the ALJ presiding over the proceeding issued a "presiding officer" decision. Although the decision found that penalties were not warranted, the decision orders the Utility to refund, at shareholder expense, approximately $23 million to customers for "illegal backbill charges" relating to estimated and delayed bills that were charged to customers in excess of the time limits in the Utility's tariff. The decision also orders the Utility to refund reconnection fees and "pay credits to certain customers whose service was shutoff for nonpayment of illegal backbills."

Under CPUC rules, parties in an adjudicatory proceeding may appeal the presiding officer's decision within 30 days. In addition, any Commissioner may request review of the presiding officer's decision within 30 days of the date of issuance. If no appeal or request for review is filed within 30 days, the presiding officer's decision will become the final CPUC decision. The Utility intends to appeal the presiding officer's

decision.

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

Energy Efficiency Rulemaking

In April 2006, the CPUC began a proceeding to consider establishing new energy efficiency policies and programs, including mechanisms that would provide incentives or impose penalties on the investor-owned utilities depending on the extent to which the utilities successfully implement their 2006-2008 energy efficiency programs and meet the CPUC's targets for reducing customers' demand for electricity and natural gas. Under the Utility's current proposed incentive mechanism, if the Utility achieved 80% to 100% of the CPUC's demand reduction targets, 80% of the net present value of energy efficiency programs (i.e., the net benefits) would accrue to customers and 20% of the net benefits would accrue to shareholders. If the Utility exceeds 100% of the CPUC's targets, the Utility's shareholders would receive 30% of the additional net benefits attributable to the portion of demand reduction that exceeds 100% of the CPUC's targets and the Utility's customers would receive the remaining 70%. Other parties have proposed that the Utility begin earning incentives only when the Utility reached 85% of the CPUC's targets and obtain earnings ranging from only 1% to 3% of the net benefits. All parties have proposed penalties for poor performance in achieving the CPUC's targets. The Utility has proposed that if it achieves less than 40% of the CPUC's targets, the Utility would provide customers any shortfall between the revenues received in rates for energy efficiency and benefits obtained through the energy efficiency programs. Other parties have proposed that penalties be imposed if the Utility achieves less than 50% to 85% of the CPUC's targets.

It is anticipated that the CPUC will issue a final decision on the adoption of a shareholder incentive and penalty mechanism in the first half of 2007. Depending upon the ratemaking method adopted by the CPUC, actual shareholder incentives or penalties may not be realized for several years. In addition to proposed mechanisms for shareholder incentives or penalties, other issues to be considered include evaluation, measurement and verification of the Utility's energy efficiency implementation results, examining energy savings arising from water efficiency (through reduced water pumping or treatment) and planning for energy efficiency programs to be implemented in 2009-2011.

PG&E Corporation and the Utility are unable to predict what rules and policies the CPUC may ultimately adopt and what impact the adopted shareholder incentive and penalty mechanism may have on their financial condition and results of operations.

Catastrophic Event Memorandum Account Application

From late December 2005 to early January 2006, winter storms disrupted service to approximately 1.5 million electric customers and damaged the Utility's electric distribution facilities and generation facilities. In addition, from mid to late July 2006, all parts of the Utility's service territory experienced unusually high temperatures, contributing to a "heat storm" that disrupted service to approximately 1.2 million electric customers and damaged the Utility's electric distribution facilities. Total costs to restore service and repair facilities from these events, including work completed in 2006 and work that is scheduled to be completed in 2007, are expected to amount to a total of $62 million.

The CPUC allows utilities to recover the reasonable costs of responding to catastrophic events through a catastrophic event memorandum account, or CEMA. The CEMA tariff authorizes recovery of costs when a catastrophic event has been declared a disaster or state of emergency by competent state or federal authorities. The California Governor proclaimed a state of emergency to exist due to the damage caused by the winter storms. The United States Department of Agriculture and several county governments declared a disaster designation or local emergency for several of California's counties as a result of the July "heat storm." Among other issues to be decided in a CEMA proceeding, the CPUC conducts a review to determine whether the costs were prudently incurred and incremental to revenue requirements previously authorized by the CPUC.

In November 2006, the Utility filed its 2006 CEMA application for the winter storms and the July 2006 "heat storm" requesting rate recovery of approximately $45 million in 2008 rates for recovery of the CEMA costs. In December 2006, DRA and TURN filed protests to the Utility's 2006 application indicating their intention to review final recorded 2006 data and investigate whether the costs included in the Utility's request are incremental to costs already included in rates. In addition, the assigned ALJ has raised doubts about the sufficiency of the July heat storm disaster declarations to trigger eligibility for CEMA relief. In January 2007, the Utility filed its brief on this issue.

PG&E Corporation and the Utility are unable to predict whether the CPUC will approve the CEMA application or the amount of any potential recovery.

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 and interest rate risk.

As long as the Utility can conclude that it is probable its reasonably incurred wholesale electricity procurement costs are recoverable through the regulatory mechanisms described above under "Regulatory Matters - Electricity Generation Resources," fluctuations in electricity prices will not affect earnings but may impact cash flows . The Utility's natural gas procurement costs for its core customers are recoverable through the CPIM and other ratemaking mechanisms, as described below. The Utility's natural gas transportation and storage costs for core customers are also fully recoverable through a ratemaking mechanism. However, the Utility's natural gas transportation and storage costs for non-core customers may not be fully recoverable. The Utility is subject to price and volumetric risk for the portion of intrastate natural gas transportation and storage capacity that has not been sold under long term contracts providing for the recovery of all fixed costs through the collection of fixed reservation charges. The Utility sells most of its capacity based on the volume of gas that the Utility's customers actually ship, which exposes the Utility to volumetric risk. Movement in interest rates can also cause earnings and cash flow to fluctuate.

The Utility actively manages market risks through risk management programs designed to support business objectives, discourage unauthorized risk-taking, reduce commodity cost 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, such as 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 brokers, and electronic exchanges, supplemented by online price information from news services. When market data is not available, the Utility uses models to estimate fair value.

Price Risk

Electricity Procurement

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. W hen customer demand exceeds the amount of electricity that can be economically produced from the Utility's own generation facilities plus net energy purchase contracts (including DWR contracts allocated to the Utility's customers), the Utility will be in a "short" position. In order to satisfy the short position, the Utility purchases electricity in the hour and day ahead markets or in the forward markets (the majority of which occurs through contracts with delivery times ranging up to five or six years forward). The FERC has adopted a "soft" cap on energy prices of $400 per megawatt hour, or MWh, that applies to the spot market (i.e., real-time, hour-ahead and day-ahead markets) throughout the Western Electricity Coordinating Council area. This "soft" cap also applies to prices for ancillary services within the markets administered by the CAISO. (A "soft" cap allows market participants to submit bids that exceed the bid cap if adequately justified, but does not allow such bids to set the market clearing price. A "hard" cap prohibits bids that exceed the cap, regardless of the seller's costs.)

When the Utility's supply of electricity from its own generation resources plus net energy purchase contracts exceeds customer demand, the Utility is in a "long" position. When the Utility is in a long position, the Utility sells the excess supply in the hour- and day-ahead markets or in the forward markets. Price risk is associated with the uncertainty of prices when buying or selling to reduce open positions (short or long positions).

The amount of electricity the Utility needs to meet the demands of customers that is not satisfied from the Utility's own generation facilities, existing purchase contracts or DWR contracts allocated to the Utility's customers, is subject to change for a number of reasons, including:

- periodic expirations of existing electricity purchase contracts, or entering into new 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, weather, implementation of new energy efficiency and demand response programs, direct access, and community choice aggregation;
- the acquisition, retirement or closure of generation facilities; and

- changes in market prices that make it more economical to purchase power in the market rather than use the Utility's existing resources.

In addition, a failure to perform by any of the counterparties to electricity purchase contracts or the DWR allocated contracts would reduce the size of the Utility's electricity supply portfolio. To the extent such a failure resulted in the Utility being in a short position the Utility may find it necessary to procure electricity at then-current market prices, which may be higher than those prices contained in the contract. In particular, Calpine Corporation and certain of its subsidiaries that have filed Chapter 11 petitions, or Calpine, sought to reject certain power purchase contracts under which they provide electricity needed by the Utility's customers. A federal district court ruled that it lacks jurisdiction to authorize Calpine to reject the contracts, finding that the FERC has exclusive jurisdiction. Calpine has appealed that decision. In the interim, the Utility and Calpine reached a settlement that replaces the contracts entered into between Calpine and the Utility, but a DWR allocated contract that supplies approximately 11% of the electricity needed by the Utility's customers still remains at issue in Calpine's appeal. The Utility has contingency plans to ensure that it has adequate resources under contract or available if Calpine succeeds in terminating the DWR allocated contract.

Lengthy, unexpected outages of the Utility's generation facilities or other facilities from which it purchases electricity also could cause the Utility to be in a short position. It is possible that the operation of Diablo Canyon may have to be curtailed or halted as early as 2010, if suitable storage facilities are not available for spent nuclear fuel, which would cause a significant increase in the Utility's short position (see "Spent Nuclear Fuel Storage Proceedings" above). If any of these events were to occur, the Utility may find it necessary to procure electricity from third parties at then-current market prices.

The Utility expects to satisfy at least some of the forecasted short position through the CPUC-approved contracts it has entered into in accordance with its CPUC-approved long-term procurement plan covering 2005 through 2014. As discussed above under "Regulatory Matters - Electricity Generation Resources," there are regulatory mechanisms in place to permit the Utility to recover costs incurred under these contracts from customers. As long as these cost recovery mechanisms remain in place, adverse market price changes are not expected to impact the Utility's net income. The Utility is at risk to the extent that the CPUC may in the future disallow portions or the full costs of procurement transactions. Additionally, market price changes could impact the timing of the Utility's cash flows.

Natural Gas Procurement (Electric Portfolio)

A portion of the Utility's electric portfolio is exposed to natural gas price risk. The Utility manages this risk in accordance with its risk management strategies included in electricity procurement plans approved by the CPUC. The CPUC has approved the Utility's electric portfolio gas hedging plan. The expenses associated with the hedging plan are expected to be recovered in the ERRA. (See the "Electricity Generation Resources" section of this MD&A.)

Natural Gas Procurement (Core Customers)

The Utility generally enters into physical and financial natural gas commodity contracts from one to twelve 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 to meet such varying demand. The Utility's cost of natural gas purchased for its core customers includes the commodity cost, the cost of Canadian and interstate transportation, intrastate gas transmission and storage costs.

Under the 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-quarters 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.

Under the Utility's hedging plan for the winters of 2005-2008, core customers paid the cost of and received any payouts from these hedges as these transactions are handled outside of the CPIM. The Utility is at risk to the extent that the CPUC may disallow portions of the hedging cost based on its subsequent review of the Utility's compliance with the plan filed with the CPUC.

In December 2006, the Utility entered into a settlement agreement with three major consumer advocate groups that represent the interest of core customers, including the CPUC's DRA, Aglet Consumer Alliance, and TURN. The settlement is subject to CPUC approval. A decision by the CPUC is expected in the second quarter of 2007. If approved, the proposed settlement would establish a

long term hedge program outside of the CPIM for up to a three-year rolling horizon. The settlement agreement also provides that the Utility would consult with an advisory group, consisting of members of the consumer advocate groups, and would submit its annual hedging plan to the CPUC for approval. CPUC pre-approval of the annual implementation plans is intended to assure that the Utility's hedging costs will be recovered from its core procurement customers as long as the CPUC finds that the Utility implemented its hedges in accordance with the pre-approved plan. Since the settlement agreement proposes that the Utility's portfolio hedging activities would be conducted entirely outside of the CPIM, the CPIM would be modified so that 80%, instead of 75%, of any cost savings below the tolerance band would be shared with customers and the Utility would retain 20%, instead of 25%, of any cost savings.

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. Nuclear fuel costs are recovered from customers through the ERRA balancing account (see "Regulatory Matters - Electricity Generation Resources" above) and therefore changes in nuclear fuel prices are not expected to materially impact net income.

Natural Gas Transportation and Storage

The Utility faces price and volumetric risk for the portion of intrastate natural gas transportation and storage capacity that is used to serve noncore customers. This risk is mitigated to the extent these noncore customers contract for transportation and storage services under firm service agreements that provide for recovery of fixed costs through the collection of fixed reservation charges. The reservation charges under such contracts typically cover approximately 65% of the Utility's fixed costs. Price risk and volumetric risk result from variability in the price of and demand for natural gas transportation and storage services, respectively. Transportation and storage services are sold at both tariffed rates and competitive market-based rates within a cost-of-service tariff framework.

The Utility uses value-at-risk to measure the shareholder's exposure to price and volumetric risks that could impact revenues due to changes in market prices, customer demand and weather. Value-at-risk measures this exposure over a rolling 12-month forward period and assumes that the contract positions are held through expiration. This calculation is based on a 99% confidence level, which means that there is a 1% probability that the impact to revenues on a pre-tax basis, over the rolling 12-month forward period, will be at least as large as the reported value-at-risk. Value-at-risk uses market data to quantify the Utility's price exposure. When market data is not available, the Utility uses historical data or market proxies to extrapolate the required market data. Value-at-risk as a measure of portfolio risk has several limitations, including, but not limited to, inadequate indication of the exposure to extreme price movements and the use of historical data or market proxies may not adequately capture portfolio risk.

The Utility's value-at-risk calculated under the methodology described above was approximately $26 million and $31 million at December 31, 2006 and December 31, 2005, respectively. The Utility's high, low, and average value-at-risk during the year ended December 31, 2006 and December 31, 2005 were approximately $41 million, $22 million and $33 million, and $43 million, $31 million and $36 million, respectively.

Convertible Subordinated Notes

At December 31, 2006, PG&E Corporation had outstanding $280 million of Convertible Subordinated Notes that 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. In addition, holders of the Convertible Subordinated Notes are entitled to receive "pass-through dividends" determined by multiplying the cash dividend paid by PG&E Corporation per share of common stock by a number equal to the principal amount of the Convertible Subordinated Notes divided by the conversion price. In connection with common stock dividends paid to holders of PG&E Corporation common stock, PG&E Corporation paid approximately $24 million of "pass through dividends" to the holders of Convertible Subordinated Notes in 2006. The holders have a one-time right to require PG&E Corporation to repurchase the Convertible Subordinated Notes on June 30, 2007, at a purchase price equal to the principal amount plus accrued and unpaid interest (including liquidated damages and unpaid "pass-through dividends," if any).

In accordance with SFAS No. 133, the dividend participation rights component of the Convertible Subordinated Notes is considered to be an embedded derivative instrument and, therefore, must be bifurcated from the Convertible Subordinated Notes and recorded at fair value in PG&E Corporation's Consolidated Financial Statements. Changes in the fair value are recognized in PG&E Corporation's Consolidated Statements of Income as a non-operating expense or income (included in Other income (expense), net). At December 31, 2006 and December 31, 2005, the total estimated fair value of the dividend participation rights component, on a pre-tax basis, was approximately $79 million and $92 million, respectively, of which $23 million and $22 million, respectively, was classified

as a current liability (in Current Liabilities - Other) and $56 million and $70 million, respectively, was classified as a noncurrent liability (in Noncurrent Liabilities - Other).

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 December 31, 2006, if interest rates changed by 1% for all current variable rate debt issued by PG&E Corporation and the Utility, the change would affect net income by less than $6 million, based on net variable rate debt and other interest rate-sensitive instruments outstanding.

CRITICAL ACCOUNTING POLICIES

The preparation of Consolidated Financial Statements in accordance with the accounting principles generally accepted in the United States of America involves the use of estimates and assumptions that affect the recorded amounts of assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The accounting policies described below are considered to be critical accounting policies, due, in part, to their complexity and because their application is relevant and material to the financial position and results of operations of PG&E Corporation and the Utility, and because these policies require the use of material judgments and estimates. Actual results may differ substantially from these estimates. These policies and their key characteristics are 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. SFAS No. 71 applies to regulated entities whose rates are designed to recover the cost of providing service. SFAS No. 71 applies to all of the Utility's operations.

Under SFAS No. 71, incurred costs that would otherwise be charged to expense may be capitalized and recorded as regulatory assets if it is probable that the incurred costs will be recovered in future rates. The regulatory assets are amortized over future periods consistent with the inclusion of costs in authorized customer rates. If costs that a regulated enterprise expects to incur in the future are being recovered through current rates, SFAS No. 71 requires that the regulated enterprise record those expected future costs as regulatory liabilities. 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 ALJ 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 December 31, 2006, PG&E Corporation and the Utility reported regulatory assets (including current regulatory balancing accounts receivable) of approximately $5.5 billion and regulatory liabilities (including current balancing accounts payable) of approximately $4.4 billion.

Unbilled Revenues

The Utility records revenue as electricity and natural gas are delivered. Amounts delivered to customers are determined through the systematic readings of customer meters performed on a monthly basis. At the end of each month, the electric and gas usage from the last meter reading is estimated and corresponding unbilled revenue is recorded. The estimate of unbilled revenue is determined by factoring an estimate of the electricity and natural gas load delivered with recent historical usage and rate patterns.

In the following month, the estimate for unbilled revenue is reversed and actual revenue is recorded based on meter readings. The accuracy of the unbilled revenue estimate is affected by factors that include fluctuations in energy demands, weather and changes in the composition of customer classes. At December 31, 2006, accrued unbilled revenues totaled $729 million.

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 December 31, 2006, the Utility's accrual for undiscounted environmental liabilities was approximately $511 million. The Utility's undiscounted future costs could increase to as much as $782 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.

The accrual for undiscounted environmental liabilities is representative of future events that are likely to occur. In determining maximum undiscounted future costs, events that are possible but not likely are included in the estimation.

Asset Retirement Obligations

The Utility accounts for its long-lived assets under SFAS No. 143, "Accounting for Asset Retirement Obligations," or SFAS No. 143, and Financial Accounting Standards Board, or FASB, Interpretation Number 47, “Accounting for Conditional Asset Retirement Obligations - An Interpretation of SFAS No. 143”, or FIN 47. SFAS No. 143 and FIN 47 require 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 FIN 47 and costs recovered through the ratemaking process.

The fair value of asset retirement obligations are dependent upon the following components:

- *Decommissioning costs* - The estimated costs for labor, equipment, material and other disposal costs;
- *Inflation adjustment* - The estimated cash flows are adjusted for inflation estimates;
- *Discount rate* - The fair value of the obligation is based on a credit-adjusted risk free rate that reflects the risk associated with the obligation; and
- *Third party markup adjustments* - Internal labor costs included in the cash flow calculation were adjusted for costs that a third party would incur in performing the tasks necessary to retire the asset in accordance with SFAS No. 143.

Changes in these factors could materially affect the obligation recorded to reflect the ultimate cost associated with retiring the assets under SFAS No. 143 and FIN 47. For example, if the inflation adjustment increased 25 basis points, this would increase the balance for asset retirement obligations by approximately 9%. Similarly, an increase in the discount rate by 25 basis points would decrease asset retirement obligations by 3%. At December 31, 2006, the Utility's estimated cost of retiring these assets is approximately $1.5 billion.

Accounting for Income Taxes

PG&E Corporation and the Utility account for income taxes in accordance with SFAS No. 109, “Accounting for Income Taxes,” which requires judgment regarding the potential tax effects of various transactions and ongoing operations to determine obligations owed to tax authorities. Amounts of deferred income tax assets and liabilities, as well as current and noncurrent accruals, involve estimates of the timing and probability of recognition of income and deductions. Actual income taxes could vary from estimated amounts due to the future impacts of various items including changes in tax laws, PG&E Corporation's financial condition in future periods, and the final review of filed tax returns by taxing authorities.

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 postretirement benefits"). Amounts that PG&E Corporation and the Utility recognize as costs and obligations to provide pension benefits under SFAS No. 158, “Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans,” or SFAS No. 158, SFAS No. 87, "Employers'

Accounting for Pensions," or SFAS No. 87, and other benefits under SFAS No. 106,

"Employers' Accounting for Postretirement Benefits other than Pensions," or SFAS No. 106, 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.

Actuarial assumptions used in determining pension obligations include the discount rate, the average rate of future compensation increases and the expected return on plan assets. Actuarial assumptions used in determining other postretirement benefit obligations include the discount rate, the expected return on plan assets and the assumed health care cost trend rate. PG&E Corporation and the Utility review these assumptions on an annual basis and adjust them as necessary. While PG&E Corporation and the Utility believe the assumptions used are appropriate, significant differences in actual experience, plan changes or significant changes in assumptions may materially affect the recorded pension and other postretirement benefit obligations and future plan expenses.

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 in accumulated other comprehensive income 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. PG&E Corporation's and the Utility's recorded pension expense totaled $185 million in 2006, $176 million in 2005 and $182 million in 2004 in accordance with the provisions of SFAS No. 87. PG&E Corporation's and the Utility's recorded expense for other postretirement benefits totaled $49 million in 2006, $55 million in 2005 and $78 million in 2004 in accordance with the provisions of SFAS No. 106.

As of December 31, 2006, PG&E Corporation and the Utility adopted SFAS No. 158 which requires the funded status of an entity's plans to be recognized on the balance sheet with an offsetting entry to accumulated other comprehensive income, resulting in no impact to the statement of income. In accordance with the provisions of SFAS No. 158, PG&E Corporation and the Utility recorded a net pension benefit liability equal to the underfunded status of certain pension plans at December 31, 2006 in the amounts of $70 million and $29 million, respectively. In addition, PG&E Corporation and the Utility recorded a net pension benefit asset equal to the overfunded status of certain pension plans in the amount of $34 million at December 31, 2006. PG&E Corporation and the Utility recorded a net benefit liability equal to the underfunded status of the other postretirement benefit plans at December 31, 2006 in the amount of $54 million.

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. Since 1993, the CPUC has authorized the Utility to recover the costs associated with its other benefits based on the lesser of the SFAS No. 106 expense or the annual tax-deductible contributions to the appropriate trusts.

PG&E Corporation's and the Utility's funding policy is to contribute tax deductible amounts, consistent with applicable regulatory decisions and federal minimum funding requirements. Based upon current assumptions and available information, PG&E Corporation and the Utility have not identified any minimum funding requirements related to its pension plans.

In July 2006, the CPUC approved the Utility's 2006 Pension Contribution Application to resume rate recovery for the Utility's contributions to the qualified defined benefit pension plan for the years 2006 through 2009, with the goal of a fully funded status by 2010. PG&E Corporation and the Utility made total contributions to the qualified defined benefit pension plan of approximately $295 million in 2006, of which $20 million related to 2005, and expect to make total contributions of approximately $176 million annually for the years 2007, 2008 and 2009. PG&E Corporation and the Utility made total contributions of approximately $25 million in 2006 related to their other postretirement benefit plans. Contribution estimates for the Utility's other postretirement benefit plans after 2006 will be driven by future GRC decisions and in line with the Utility's funding policy.

Pension and other postretirement benefit funds are held in external trusts. Trust assets, including accumulated earnings, must be used exclusively for pension and other postretirement benefit payments. Consistent with the trusts' investment policies, assets are invested in U.S. equities, non-U.S. equities and fixed income securities. Investment securities are exposed to various risks, including interest rate, credit and overall market volatility. As a result of these risks, it is reasonably possible that the market values of investment securities could increase or decrease in the near term. Increases or decreases in market values could materially affect the current value of the trusts and, as a result, the future level of pension and other postretirement benefit expense.

Expected rates of return on plan assets were developed by determining projected stock and bond returns and then applying these returns to the target asset allocations of the employee benefit trusts, resulting in a weighted average rate of return on plan assets.

Fixed income returns were projected based on real maturity and credit spreads added to a long-term inflation rate. Equity returns were estimated based on estimates of dividend yield and real earnings growth added to a long-term rate of inflation. For the Utility Retirement Plan, the assumed return of 8.0% compares to a ten-year actual return of 9.0%.

The rate used to discount pension and other postretirement benefit plan liabilities was based on a yield curve developed from market data of over 500 Aa-grade non-callable bonds at December 31, 2006. This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other postretirement obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

The following reflects the sensitivity of pension costs and projected benefit obligation to changes in certain actuarial assumptions:

(in millions)	Increase (decrease) in Assumption	Increase in 2006 Pension Cost	Increase in Projected Benefit Obligation at December 31, 2006
Discount rate	(0.5)%	$ 73	$ 643
Rate of return on plan assets	(0.5)%	40	-
Rate of increase in compensation	0.5%	30	139

The following reflects the sensitivity of other postretirement benefit costs and accumulated benefit obligation to changes in certain actuarial assumptions:

(in millions)	Increase (decrease) in Assumption	Increase in 2006 Other Postretirement Benefit Cost	Increase in Accumulated Benefit Obligation at December 31, 2006
Health care cost trend rate	0.5%	$ 5	$ 36
Discount rate	(0.5)%	5	81

ACCOUNTING PRONOUNCEMENTS ISSUED BUT NOT YET ADOPTED

Accounting for Uncertainty in Income Taxes

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

Fair Value Measurements

In September 2006, the FASB issued SFAS No. 157, “Fair Value Measurements,” or SFAS No. 157. SFAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. SFAS No. 157 also establishes a framework for measuring fair value and provides for expanded disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. PG&E Corporation and the Utility are currently evaluating the impact of SFAS No. 157.

Fair Value Option

In February 2007, the FASB issued SFAS No. 159, “The Fair Value Option for Financial Assets and Financial Liabilities,” or SFAS No. 159. SFAS No. 159 establishes a fair value option under which entities can elect to report certain financial asset and liabilities at fair value, with changes in fair value recognized in earnings. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. PG&E Corporation and the Utility are currently evaluating the impact of SFAS No. 159.

TAXATION MATTERS

See Note 11 of the Notes to the Consolidated Financial Statements for discussion on taxation matters.

ENVIRONMENTAL MATTERS

The Utility may be required to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party under the Comprehensive Environmental Response Compensation and Liability Act of 1980, as amended, and similar state environmental laws. These sites include former manufactured gas plant sites, power plant sites, and sites used by the Utility for the storage, recycling or disposal of potentially hazardous materials. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if the Utility did not deposit those substances on the site.

The cost of environmental remediation is difficult to estimate. The Utility records an environmental remediation liability when site assessments indicate 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. The Utility estimates the upper end of this cost range using reasonably possible outcomes that are least favorable to the Utility. It is reasonably possible that a change in these estimates may occur in the near term due to uncertainty concerning the Utility's responsibility, the complexity of environmental laws and regulations, and the selection of compliance alternatives.

The Utility had an undiscounted environmental remediation liability of approximately $511 million at December 31, 2006 and approximately $469 million at December 31, 2005. The increase in the undiscounted environmental remediation reflects an increase of $74 million for remediation at the Utility’s gas compressor stations located near Hinkley, California and Topock, Arizona. The portion of the increased liability of $39 million for remediation at the Hinkley facility is attributable to changes in the California Regional Water Quality Control Board’s imposed remediation levels. Costs incurred at this facility are not recoverable from customers and, as a result, the after-tax impact on income was a reduction of approximately $23 million for 2006. Ninety percent of the estimated remediation costs associated with the Utility’s gas compressor station located near Topock, Arizona will be recoverable in rates in accordance with the hazardous waste ratemaking mechanism which permits the Utility to recover 90% of hazardous waste remediation costs from customers without a reasonableness review.

The $511 million accrued at December 31, 2006 includes:

- approximately $238 million for remediation at the Hinkley and Topock natural gas compressor sites;
- approximately $98 million related to the pre-closing remediation liability associated with divested generation facilities; and
- approximately $175 million related to remediation costs for the Utility’s generation facilities and gas gathering sites, third-party disposal sites and manufactured gas plant sites owned by the Utility or third parties (including those sites that are the subject of remediation orders by environmental agencies or claims by the current owners of the former manufactured gas plant sites).

Of the approximately $511 million environmental remediation liability, approximately $138 million has been included in prior rate setting proceedings. The Utility expects that an additional amount of approximately $272 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 $782 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 $782 million does not include any estimate for any potential costs of remediation at former manufactured gas plant sites in the Utility's service territory that were previously owned by the Utility or a predecessor but that are now owned by others because the Utility either has not been able to determine if a liability exists with respect to these sites or the Utility has not been able to estimate the amount of any future potential remediation costs that may be incurred for these sites.

In July 2004, the U.S. Environmental Protection Agency, or EPA, published regulations under Section 316(b) of the Clean Water Act for cooling water intake structures. The regulations affect existing electricity generation facilities using over 50 million gallons per day, typically including some form of "once-through" cooling. The Utility’s Diablo Canyon power plant is among an estimated 539 generation facilities nationwide that are affected by this rulemaking. The Utility permanently closed its Hunters Point

power plant in May 2006 and the Humboldt Bay power plant will be re-powered without the use of once-through cooling. The EPA regulations establish a set of performance standards that vary with the type of water body and that are intended to reduce impacts to aquatic organisms. Significant capital investment may be required to achieve the standards. The regulations allow site-specific compliance determinations if a facility's cost of compliance is significantly greater than either the benefits achieved or the compliance costs considered by the EPA and also allow the use of environmental mitigation or restoration to meet compliance requirements in certain cases. Various parties challenged the EPA's regulations and the cases were consolidated in U.S. Court of Appeals for the Second Circuit, or Second Circuit.

On January 25, 2007, the Second Circuit issued its decision on the appeals of the EPA Section 316(b) regulations. The Second Circuit remanded significant provisions of the regulations to EPA for reconsideration and held that a cost benefit test cannot be used to establish performance standards or to grant variances from the standards. The Second Circuit also ruled that environmental restoration cannot be used to achieve compliance. The parties may seek either en banc review by the Second Circuit or review by the U.S. Supreme Court. Regardless of whether the decision is subject to further judicial review, the EPA will likely require significant time to review and revise the regulations. It is uncertain how the Second Circuit decision will affect development of the state's proposed implementation policy. The regulatory uncertainty is likely to continue and the Utility's cost of compliance, while likely to be significant, will remain uncertain as well.

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. See Note 17 of the Notes to the 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 position or results of operations.

RISK FACTORS

Risks Related to PG&E Corporation

PG&E Corporation could be required to contribute capital to the Utility or be denied distributions from the Utility to the extent required by the CPUC's determination of the Utility's financial condition.

In approving the original formation of a holding company for the Utility, the CPUC imposed certain conditions, including an obligation by PG&E Corporation's Board of Directors to give "first priority" to the capital requirements of the Utility, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner. The CPUC later issued decisions in which it adopted an expansive interpretation of PG&E Corporation's obligations under this condition, including the requirement that PG&E Corporation "infuse the [U]tility with all types of capital necessary for the [U]tility to fulfill its obligation to serve." The CPUC's expansive interpretation could require PG&E Corporation to infuse the Utility with significant capital in the future, or be denied distributions from the Utility, which could materially restrict PG&E Corporation's ability to meet other obligations.

Adverse resolution of pending litigation could have a material adverse effect on PG&E Corporation's financial condition and results of operation.

In 2002, the California Attorney General and the City and County of San Francisco filed complaints against PG&E Corporation alleging that certain conditions imposed by the CPUC in approving the holding company formation, including the so-called "first priority condition," were violated and that these alleged violations constituted unfair or fraudulent business acts or practices in violation of Section 17200 of the California Business and Professions Code. They allege that transfers of funds from the Utility to PG&E Corporation during the period 1997 through 2000 (primarily in the form of dividends and stock repurchases), and from PG&E Corporation to other affiliates of PG&E Corporation, violated these holding company conditions. They also allege that PG&E Corporation wrongfully failed to provide adequate financial support to the Utility in 2000 and 2001 during the California energy crisis. The plaintiffs seek restitution of amounts alleged to have been wrongly transferred estimated by plaintiffs to be approximately $5 billion, civil penalties of $2,500 against each defendant for each violation of Section 17200, a total penalty of not less than $500 million, and costs of suit, among other remedies.

An adverse outcome, particularly one imposing significant penalties, could have a material adverse affect on PG&E Corporation's financial condition, results of operations and cash flows.

Risks Related to the Utility

PG&E Corporation's and the Utility's financia l condition depends upon the Utility's ability to recover its costs in a timely manner from the Utility's customers through regulated rates and otherwise execute its business strategy.

The Utility is a regulated entity subject to CPUC and FERC jurisdiction in almost all aspects of its business, including the rates, terms and conditions of its services, procurement of electricity and natural gas for its customers, issuance of securities, dispositions of utility assets and facilities, and aspects of the siting and operation of its electricity and natural gas operating assets. Executing the Utility's business strategy depends on periodic regulatory approvals related to these and other matters.

The Utility's financial condition particularly depends on its ability to recover in rates in a timely manner the costs of electricity and natural gas purchased for its customers, as well as an adequate return on the capital invested in its utility assets, including the long-term debt and equity issued to finance their acquisition. There may be unanticipated changes in operating expenses or capital expenditures that cause material differences between forecasted costs used to determine rates and actual costs incurred which, in turn, affect the Utility's ability to earn its authorized rate of return. The CPUC also has approved various programs to support public policy goals through the use of customer incentives and subsidies for energy efficiency programs and the development and use of renewable and self-generation technologies. These and other similar incentives and subsidies increase the Utility's overall costs. As rate pressure increases, the risk increases that the CPUC or other state authority will disallow recovery of some of the Utility's costs based on a determination that the costs were not reasonably incurred or for some other reason, resulting in stranded investment capital.

Further, changes in laws and regulations or changes in the political and regulatory environment may have an adverse effect on the Utility's ability to timely recover its costs and earn its authorized rate of return. During the 2000-2001 energy crisis that followed the implementation of California's electric industry restructuring law, the Utility could not recover in rates the high prices it had to pay for wholesale electricity, which ultimately caused the Utility to file a petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code. Even though the Chapter 11 Settlement Agreement and current regulatory mechanisms contemplate that the CPUC will give the Utility the opportunity to recover its reasonable and prudent future costs of electricity and natural gas in its rates, there can be no assurance that the CPUC will find that all of the Utility's costs are reasonable and prudent or will not otherwise take or fail to take actions to the Utility's detriment.

In addition, there can be no assurance that the bankruptcy court or other courts will implement and enforce the terms of the Chapter 11 Settlement Agreement and the Utility's plan of reorganization in a manner that would produce the economic results that PG&E Corporation and the Utility intend or anticipate. Further, there can be no assurance that FERC-authorized tariffs will be adequate to cover the related costs. The Utility's failure to recover any material amount of its costs through its rates in a timely manner , would have a material adverse effect on PG&E Corporation's and the Utility's financial condition, results of operations and cash flows.

The Utility faces significant uncertainty in connection with the implementation of the CAISO's Market Redesign and Technology Upgrade program to restructure California's wholesale electricity market. In addition, the Utility must comply with new reliability standards being promulgated under the Energy Policy Act of 2005.

In response to the market manipulation that occurred during the 2000-2001 energy crisis, the CAISO has undertaken a Market Redesign and Technology Upgrade , or MRTU , initiative to implement a new day-ahead wholesale electricity market , and improve electricity grid management reliability, operational efficiencies and related technology infrastructure. MRTU, scheduled to become effective in January 2008, will add significant market complexity and will require major changes to the Utility's systems and software interfacing with the CAISO. Also, as part of the implementation of the Energy Policy Act of 2005, new mandatory standards are being developed relating to the operation and maintenance of the electric grid. The new standards are subject to the FERC's approval and new enforcement authority. The FERC can impose significant penalties ($1,000,000 per day per violation) for failure to comply with the reliability standards. If the Utility incurs significant costs to implement MRTU that are not timely recovered from customers or if the new market mechanisms created by MRTU fail to react promptly to price/market flaws or if the needed systems and software interfaces do not perform as intended, or if the Utility fails to comply with the new electric reliability standards, PG&E Corporation's and the Utility's financial condition, results of operations and cash flows could be materially adversely affected.

The Utility may be unable to achieve expected cost savings and efficiencies from its customer service improvement initiatives.

During 2006, the Utility began to implement various initiatives to change its business processes and systems so as to achieve operational excellence and to provide better, faster and more cost-effective service to its customers. Many of these initiatives require

substantial costs to implement with savings expected to be realized in later years. The proposed settlement of the Utility's 2007 GRC contemplates that customers would receive the benefit of cost savings attributable to implementation of these initiative s in 2008, 2009 and 2010. If the actual cost savings exceed the contemplated savings , such benefits would accrue to shareholders. Conversely, if any of these cost savings are not realized, earnings available for shareholders would be reduced.

There can be no assurance that the Utility will be able to recognize cost savings through implementation of these initiatives and its failure to do so could have a material adverse effect on PG&E Corporation's and the Utility's financial condition , results of operations and cash flows .

The Utility may fail to recognize the benefits of its advanced metering system or the advanced metering system may fail to perform as intended resulting in higher costs and/or reduced cost savings.

During 2006, the Utility began to implement its advanced metering infrastructure project for residential and small commercial customers involving the installation of approximately 10 million advanced electricity and gas meters throughout its service territory, by the end of 2011. Advanced meters will allow customer usage data to be transmitted through a communication network to a central collection point, where the data will be stored and used for billing and other commercial purposes. The Utility expects to complete the installation of the network infrastructure and advanced meters throughout its service territory by the end of 2011.

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

If the Utility fails to recognize the expected benefits of its advanced metering infrastructure, if the Utility incurs additional costs that the CPUC does not find reasonable, or if the Utility is unable to integrate the new advanced metering system with its billing and other computer information systems, PG&E Corporation's and the Utility's financial condition, results of operations and cash flows could be materially adversely affected.

The Utility faces significant uncertainties associated with the future level of bundled electric load for which it must procure electricity and secure generating capacity and, under certain circumstances, may not be able to recover all of its costs .

The Utility is responsible to procure electricity to meet customer demand, plus applicable reserve margins, not satisfied from the Utility's own generation facilities and existing electricity contracts. 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. W hen customer demand exceeds the amount of electricity that can be economically produced from the Utility's own generation facilities plus net energy purchase contracts (including DWR contracts allocated to the Utility's customers), the Utility will be in a "short" position. When the Utility's supply of electricity from its own generation resources plus net energy purchase contracts exceeds customer demand, the Utility is in a "long" position. When the Utility is in a long position, the Utility sells the excess supply in the hour- and day-ahead markets or in the forward markets.

The amount of electricity the Utility needs to meet the demands of customers that is not satisfied from the Utility's own generation facilities, existing purchase contracts or DWR contracts allocated to the Utility's customers, could increase or decrease due to a variety of factors, including, without limitation, a change in the number of the Utility's customers, periodic expirations of existing electricity purchase contracts, including DWR contracts, execution of new energy and capacity purchase contracts, fluctuation in the output of hydroelectric and other renewable power facilities owned or under contract by the Utility, implementation of new energy efficiency and demand response programs, the reallocation of the DWR power purchase contracts among California investor-owned electric utilities, and the acquisition, retirement or closure of generation facilities. The amount of electricity the Utility would need to purchase would immediately increase if there was an unexpected outage at Diablo Canyon or any of its other significant generation facilities, if the Utility had to shut down Diablo Canyon for any reason , or if any of the counterparties to the Utility's electricity purchase contracts or the DWR allocated contracts did not perform due to bankruptcy or for some other reason. In addition, as the electricity supplier of last resort, the amount of electricity the Utility would need to purchase also would immediately increase if a material number of direct access customers or customers of community choice aggregators decided to return to receiving bundled services from the Utility. (See discussion of direct access and community choice aggregators above under "Regulatory Matters- Electricity Generation Resources.")

If the Utility's short position unexpectedly increases, the Utility would need to purchase electricity in the wholesale market under contracts priced at the time of execution or, if made in the spot market, at the then-current market price of wholesale electricity. The inability of the Utility to purchase electricity in the wholesale market at prices or on terms the CPUC finds reasonable or in quantities sufficient to satisfy the Utility's short position could have a material adverse effect on the financial condition, results of operations or cash flow of the Utility and PG&E Corporation.

Alternatively, the Utility would be in a long position if the number of Utility customers declined. For example, a petition was filed in late December 2006 asking the CPUC to examine re-establishing the ability of the Utility's customers to become direct access customers by purchasing electricity from alternate energy providers by January 1, 2008. Separately, the CPUC has adopted rules to implement California Assembly Bill 117 that permits California cities and counties to purchase and sell electricity for all their residents who do not affirmatively elect to continue to receive electricity from the Utility, once the city or county has registered as a community choice aggregator while the Utility continues to provide distribution, metering and billing services to the community choice aggregators' customers and serves as the electricity provider of last resort for all customers. In addition, the Utility could lose customers because of increased self-generation. The risk of loss of customers through self-generation is increasing as the CPUC has approved various programs to provide self-generation incentives and subsidies to customers to encourage development and use of renewable and distributed generating technologies, such as solar technology. The number of the Utility's customers also could decline due to a general economic downturn or if higher energy prices in California due to stricter greenhouse gas regulations or other state regulations cause customers to leave the Utility's service territory.

If the Utility experiences a material loss of customers, the Utility's existing electricity purchase contracts could obligate it to purchase more electricity than its remaining customers require. This would result in a long position and require the Utility to sell the excess, possibly at a loss. In addition, excess electricity generated by the Utility's generation facilities may also have to be sold, possibly at a loss, and costs the Utility may have incurred to develop or acquire new generation resources may become stranded .

If the CPUC fails to adjust the Utility's rates to reflect the impact of changing loads, PG&E Corporation's and the Utility's financial condition , results of operations and cash flows could be materially adversely affected.

The Utility relies on access to the capital markets. There can be no assurance that the Utility will be able to successfully finance its planned capital expenditures on favorable terms or rates.

The Utility's ability to make scheduled principal and interest payments, refinance debt, and fund operations and planned capital expenditures depends on its operating cash flow and access to the capital markets. During 2006, the CPUC authorized the Utility to make substantial capital investments in new long-term generation resources. The Utility also expects to make capital investments in electric transmission to secure access to renewable generation resources and to accommodate system load growth, in natural gas transmission to improve reliability and expand capacity and to replace aging or obsolete infrastructure (e.g ., pipelines, storage facilities and compressor stations) to maintain system reliability, and in the electric and gas distribution system. In addition, the Utility expends capital to replace, refurbish or extend the life of its existing nuclear, hydroelectric and fossil facilities. The Utility's ability to access the capital markets and the costs and terms of available financing depend on many factors, including changes in the Utility's credit ratings, changes in the federal or state regulatory environment affecting energy companies, increased or natural volatility in electricity or natural gas prices and general economic and market conditions.

PG&E Corporation's and the Utility's financial condition and results of operations would be materially adversely affected if the Utility is unable to obtain financing with favorable terms and conditions, or at all.

The completion of the Utility's capital investment projects is subject to substantial risks and the rate at which the Utility invests capital will directly affect earnings.

The completion of the Utility's anticipated capital investment projects in existing and new generation facilities, electric and gas transmission, and electric and gas distribution systems is subject to many construction and development risks, including risks related to financing, obtaining and complying with the terms of permits, meeting construction budgets and schedules, and satisfying operating and environmental performance standards. The Utility also faces the risk that it may incur costs that it will not be permitted to recover from customers. In addition, the timing and amount of capital spending will directly affect the amount the Utility is able to earn on its authorized rate base, which in turn will affect the ability of PG&E Corporation and the Utility to grow its earnings over time.

If the Utility is unable to timely meet the applicable resource adequacy or renewable energy requirements, the Utility may be subject to penalties.

The Utility must achieve an electricity planning reserve margin of 15% to 17% in excess of peak capacity electricity requirements. The CPUC can impose a penalty if it fails to acquire sufficient capacity to meet resource adequacy requirements for a

particular year. The penalty for failure to procure sufficient system resource adequacy capacity (*i.e.* , resources that are deliverable anywhere in the CAISO-controlled electricity grid) is equal to three times the cost of the new capacity the Utility should have secured. The CPUC has set this penalty at $120 per kW-year. The CPUC also adopted “local” resource adequacy requirements to set local capacity requirements in specific regions that may be transmission-constrained. The CPUC set the penalty for failure to meet local resource adequacy requirements at $40 per kW-year. In addition to penalties, entities that fail to meet resource adequacy requirements may be assessed the cost of backstop procurement by the CAISO to fulfill their resource adequacy target levels.

In addition, the R PS established under state law requires the Utility to increase its purchases of renewable energy each year so that the amount of electricity purchased from eligible renewable resources equals at least 20% of its total retail sales by the end of 2010. The CPUC has established penalties of $50 per MWh, up to $25 million per year, for failure to comply with the RPS requirements.

The Utility faces the risk of unrecoverable costs if its customers obtain distribution and transportation services from other providers as a result of municipalization, technological change, or other forms of bypass.

The Utility's customers could bypass its distribution and transportation system by obtaining service from other sources. Forms of bypass of the Utility's electricity distribution system include construction of duplicate distribution facilities to serve specific existing or new customers and condemnation of the Utility's distribution facilities by local governments or municipal districts. The Utility's natural gas transportation facilities could also be at risk of being bypassed by interstate pipeline companies that construct facilities in the Utility's markets or by customers who build pipeline connections that bypass the Utility's natural gas transportation and distribution system, or by customers who use and transport liquefied natural gas, or LNG .

As customers and local public officials continue to explore their energy options, these bypass risks may be increasing and may increase further if the Utility's rates exceed the cost of other available alternatives, resulting in stranded investment capital, loss of customer growth and additional barriers to cost recovery. As examples, the Sacramento Municipal Utility District , or SMUD, sought to proceed with plans to exercise its power of eminent domain to acquire portions of the Utility's electric system within Yolo County which serves approximately 70,000 Utility customers and the South San Joaquin Irrigation District , or SSJID , has sought approval from the local agency formation commission to serve portions of the Utility's electric system within San Joaquin County. Although SMUD's plans were ultimately defeated by voters in Yolo and Sacramento Counties on November 7, 2006 and SSJIDs’ plans have been rejected by the local agency formation commission, there is no assurance that SSJID may not continue to pursue its efforts, or that others may not choose to follow a similar path.

If the number of the Utility's customers declines due to municipalization, or other forms of bypass, and the Utility's rates are not adjusted in a timely manner to allow it to fully recover its investment in electricity and natural gas facilities and electricity procurement costs, PG&E Corporation's and the Utility's financial condition , results of operations and cash flows could be materially adversely affected.

Electricity and natural gas markets are highly volatile and regulatory responsiveness to that volatility could be insufficient.

Commodity markets for electricity and natural gas are highly volatile and subject to substantial price fluctuations. A variety of factors that are largely outside of the Utility’s control may contribute to commodity price volatility, including:

- weather;
- supply and demand;
- the availability of competitively priced alternative energy sources;
- the level of production of natural gas;
- the availability of nuclear fuel;
- the availability of LNG supplies;
- the price of fuels that are used to produce electricity, including natural gas, crude oil, coal and nuclear materials;
- the transparency, efficiency, integrity and liquidity of regional energy markets affecting California;
- electricity transmission or natural gas transportation capacity constraints;

- federal, state and local energy and environmental regulation and legislation; and
- natural disasters, war, terrorism, and other catastrophic events.

Beginning in July 2006, the fixed price provisions of the Utility's power purchase agreements with QFs expired and QFs became able to pass on their cost of the natural gas they purchase as fuel for their generating facilities to the Utility, increasing the Utility's exposure to natural gas price volatility. The expiration of fixed price provisions in the DWR contracts allocated to the Utility at the end of 2009 will further increase the Utility's exposure to natural gas price risk. Although the Utility attempts to execute CPUC-approved hedging programs to reduce the natural gas price risk, there can be no assurance that these hedging programs will be successful or that the costs of the Utility's hedging programs will be fully recoverable.

Further, if wholesale electricity or natural gas prices increase significantly, public pressure or other regulatory or governmental influences or other factors could constrain the willingness or ability of the CPUC to authorize timely recovery of the Utility's costs from customers. If the Utility is unable to recover any material amount of its costs in its rates in a timely manner, PG&E Corporation's and the Utility's financial condition , results of operations and cash flows would be materially adversely affected.

The Utility's financial condition and results of operations could be materially adversely affected if it is unable to successfully manage the risks inherent in operating the Utility's facilities.

The Utility owns and operates extensive electricity and natural gas facilities that are interconnected to the U.S. western electricity grid and numerous interstate and continental natural gas pipelines. The operation of the Utility's facilities and the facilities of third parties on which it relies involves numerous risks, including:

- operating limitations that may be imposed by environmental laws or regulations, including those relating to greenhouse gases , or other regulatory requirements;
- imposition of operational performance standards by agencies with regulatory oversight of the Utility 's facilities;
- environmental accidents, including the release of hazardous or toxic substances into the air or water, urban wildfires and other events caused by operation of the Utility's facilities or equipment failure ;
- fuel supply interruptions;
- blackouts ;
- failure of the Utility's computer information systems, including those relating to operations or financial information such as customer billing ;
- labor disputes, workforce shortage, availability of qualified personnel;
- weather , storms, earthquakes, fires, floods or other natural disasters, war, pandemic and other catastrophic events;
- explosions , accidents, dam failure, mechanical breakdowns , terrorist activities ; and
- other events or hazards

that affect demand for electricity or natural gas, result in unplanned outages, reduce generating output, cause damage to the Utility's assets or operations or those of third parties on which it relies, or subject the Utility to third party claims or liability for damage or injury.

In addition, substantial uncertainty exists relating to the potential impacts of climate change on the Utility's electricity and natural gas operations as a result of increased frequency and severity of hot weather, decreased hydroelectric generation resulting from reduced runoff from snow pack and increased sea level along the Northern California coastal area. Climate change is likely to affect the operation of the Utility's hydroelectric system and to lead to more severe weather events which will increase the need for additional generation capacity without commensurate increases in average load.

The impact of these events could range from highly localized to worldwide, and in certain events could result in a full or partial disruption of the ability of the Utility or one or more entities on which it relies to generate, transmit, transport or distribute electricity or natural gas or cause environmental repercussions. Even the less extreme events could result in lower revenues or increased expenses, or both, that may not be fully recovered through rates or other means in a timely manner or at all . In addition, the Utility's insurance may not be sufficient or effective to provide recovery under all circumstances or against all hazards or liabilities to which the Utility is or may become subject. An uninsured loss could have a material adverse effect on PG&E Corporation's and the Utility's financial condition, results of operations and cash flows. Future insurance coverage may not be available at rates and on terms as favorable as the rates and terms of the Utility's current insurance coverage.

The Utility's operations are subject to extensive environmental laws, and changes in, or liabilities under, these laws could adversely affect its financial condition and results of operations.

The Utility's operations are subject to extensive federal, state and local environmental laws and permits. Complying with these environmental laws has in the past required significant expenditures for environmental compliance, monitoring and pollution control equipment, as well as for related fees and permits. Moreover, compliance in the future may require significant expenditures relating to reduction of greenhouse gases, regulation of water intake or discharge at certain facilities, and mitigation measures associated with electric and magnetic fields. New California legislation imposes a state-wide limit on the emission of greenhouse gases that must be achieved by 2020 and prohibits load-serving entities, including investor-owned utilities , from entering into long term financial commitments for generation resources unless the new generation resources conform to a greenhouse gas emission performance standard. Congress may also enact legislation to limit greenhouse gas emissions. Depending on how the baseline for greenhouse gas emissions level is set, complying with California regulation and potential federal legislation may subject the Utility to significant costs. The Utility has significant liabilities (currently known, unknown, actual and potential) related to environmental contamination at Utility facilities, including natural gas compressor stations and former manufactured gas plants, as well as at third-party owned sites. The Utility's environmental compliance and remediation costs could increase, and the timing of its capital expenditures in the future may accelerate, if standards become stricter, regulation increases, other potentially responsible parties cannot or do not contribute to cleanup costs, conditions change or additional contamination is discovered.

In the event the Utility must pay materially more than the amount that it currently has reserved on its Consolidated Balance Sheets to satisfy its environmental remediation obligations and cannot recover those or other costs of complying with environmental laws in its rates in a timely manner or at all , PG&E Corporation's and the Utility's financial condition , results of operations and cash flow would be materially adversely affected.

The operation and decommissioning of the Utility's nuclear power plants expose it to potentially significant liabilities and capital expenditures that it may not be able to recover from its insurance or other source, adversely affecting its financial condition, results of operations and cash flow .

The operation and decommissioning of the Utility's nuclear power plants expose it to potentially significant liabilities and capital expenditures, including not only the risk of death, injury and property damage from a nuclear accident, but matters arising from the storage, handling and disposal of radioactive materials including spent nuclear fuel; stringent safety and security requirements; public and political opposition to nuclear power operations; and uncertainties related to the regulatory, technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives. The Utility maintains external insurance coverage and decommissioning trusts to reduce the Utility's financial exposure to these risks. However, the costs or damages the Utility may incur in connection with the operation and decommissioning of nuclear power plants could exceed the amount of the Utility's insurance coverage and other amounts set aside for these potential liabilities. In addition, as an operator of two operating nuclear reactor units, the Utility may be required under federal law to pay up to $201.2 million of liabilities arising out of each nuclear incident occurring not only at Diablo Canyon but at any other nuclear power plant in the United States.

The NRC has broad authority under federal law to impose licensing and safety-related requirements upon owners and operators of nuclear power plants. In the event of non-compliance, the NRC has the authority to impose fines or to force a shutdown of the nuclear plant, or both, depending upon the NRC's assessment of the severity of the situation. NRC safety and security requirements have, in the past, necessitated substantial capital expenditures at Diablo Canyon an d additional significant capital expenditures could be required in the future. I f one or both units at Diablo Canyon were shut down pursuant to an NRC order or to comply with NRC licensing, safety or security requirements or due to other safety or operational issues , the Utility's operating and maintenance costs would increase. Further, such events may cause the Utility to be in a short position and the Utility would need to purchase electricity from more expensive sources.

In addition, the Utility's nuclear power operations are subject to the availability of adequate nuclear fuel supplies on terms that the CPUC will find reasonable. Although the Utility has entered several purchase agreements for nuclear fuel with terms ranging from two to five years, there is no assurance the Utility will be able to enter into similar agreements in the future with terms that the CPUC will find are reasonable.

Under the terms of the NRC operating licenses for Diablo Canyon, there must be sufficient storage capacity for the radioactive spent fuel produced by this plant. Under current operating procedures, the Utility believes that the existing spent fuel pools have sufficient capacity to enable the Utility to operate Diablo Canyon until approximately 2010 for Unit 1 and 2011 for Unit 2. After receiving a permit from the NRC in March 2004, the Utility began building an on-site dry cask storage facility to store spent fuel through at least 2024. T he Utility estimates it could complete the dry cask storage project by 2008. Following an appeal of the NRC's March 2004 decision to grant the permit, the Ninth Circuit issued a decision on June 2, 2006 that requires the NRC to consider the environmental consequences of a potential terrorist attack at Diablo Canyon as part of the NRC's supplemental assessment of the dry cask storage permit. On January 16, 2007, the U.S. Supreme Court denied the Utility's petition for review of the Ninth Circuit decision. The Utility may incur significant additional capital expenditures or experience schedule delays if the NRC decides that the Utility must change the design and construction of the dry cask storage facility. The NRC also may decide to deny the permit. There can be no assurance that the Utility can obtain the final necessary regulatory approvals to expand spent fuel capacity or that other alternatives will be available or implemented in time to avoid a disruption in production or shutdown of one or both units at this plant. If there is a disruption in production or shutdown of one or both units at this plant, the Utility will need to purchase electricity from more expensive sources.

Further, certain aspects of the Utility's nuclear operations are subject to other local and regulatory requirements that are overseen by other agencies, such as the California Coastal Commission and the Central Coast Regional Water Quality Control Board. Various parties, including local community, environmental, political, or other groups may participate, or seek to intervene, in regulatory proceedings. In addition, these groups may seek to challenge certain aspects of the Utility's nuclear operations through judicial proceedings.

If the CPUC prohibited the Utility from recovering a material amount of its capital expenditures, fuel costs, operating and maintenance costs, or additional procurement costs due to a determination that the costs were not reasonably or prudently incurred, PG&E Corporation's and the Utility's financial condition , results of operations and cash flow would be materially adversely affected.

Changes in the political and regulatory environment could cause federal and state statutes, CPUC and FERC regulations, rules and orders to become more stringent and difficult to comply with and required permits, authorizations and licenses may be more difficult to obtain increasing the Utility's expenses or making it more difficult for the Utility to execute its business strategy .

The Utility must comply in good faith with all applicable statutes, rules, tariffs and orders of the CPUC, the FERC, the NRC, and others relating to the aspects of its electricity and natural gas utility operations which fall within the jurisdictional authority of such regulatory agencies. These include customer billing, customer service, affiliate transactions, vegetation management and safety and inspection practices. There is a risk that the interpretation and application of these statutes, rules, tariffs and orders may change over time and that the Utility will be determined to have not complied with the new interpretation. If so, this could expose the Utility to increased costs to comply with the new interpretation and to potential liability for customer refunds , penalties, or other amounts. Moreover, such statutes, rules, tariffs and orders could become more stringent and difficult to comply with in the future.

If it is determined that the Utility did not comply with applicable statutes, rules, tariffs, or orders, and the Utility is ordered to pay a material amount in customer refunds, penalties, or other amounts, PG&E Corporation's and the Utility's financial condition , results of operations and cash flow would be materially adversely affected.

The Utility is also required to comply with the terms of various permits, authorizations and licenses. These permits, authorizations and licenses may be revoked or modified by the agencies that granted them if facts develop that differ significantly from the facts assumed when they were issued. In addition, discharge permits and other approvals and licenses are often granted for a term that is less than the expected life of the associated facility. Licenses and permits may require periodic renewal, which may result in additional requirements being imposed by the granting agency. In connection with a license renewal, the FERC may impose new license conditions that could, among other things, require increased expenditures or result in reduced electricity output and/or capacity at the facility.

Also, if the Utility is unable to obtain, renew or comply with these governmental permits, authorizations or licenses, or if the Utility is unable to recover any increased costs of complying with additional license requirements or any other associated costs in its rates in a timely manner, PG&E Corporation's and the Utility's financial condition and results of operations could be materially adversely affected.

The outcome of pending and future litigation and legal proceedings, the application of and changes in accounting standards or guidance, tax laws, rates or policies, also may adversely affect the Utility's financial condition, results of operations or cash flows.

In the normal course of business, the Utility in named as a party in a number of claims and lawsuits. The Utility may also be the subject of investigative or enforcement proceedings conducted by administrative or regulatory agencies. In accordance with

applicable accounting standards, the Utility makes provisions for liabilities when it is both probable that a liability has been incurred and the amount of the loss can be reasonably estimated. If the Utility incurs losses in connection with litigation or other legal, administrative or regulatory proceedings that materially exceeded the provision it made for liabilities, PG&E Corporation's and the Utility's financial condition, results of operations and cash flow would be materially adversely affected.

In addition, there is a risk that changes in accounting or tax rules, standards, guidance, policies, or interpretations, or that changes in management's estimates and assumptions underlying reported amounts of revenues, expenses, assets and liabilities, may result in write-offs, impairments or other charges that could have a material adverse affect on PG&E Corporation's and the Utility's financial condition, results of operations and cash flow.

PG&E Corporation
CONSOLIDATED STATEMENTS OF INCOME
(in millions, except per share amounts)

	Year ended December 31,		
	2006	**2005**	**2004**
Operating Revenues			
Electric	$ 8,752	$ 7,927	$ 7,867
Natural gas	3,787	3,776	3,213
Total operating revenues	12,539	11,703	11,080
Operating Expenses			
Cost of electricity	2,922	2,410	2,770
Cost of natural gas	2,097	2,191	1,724
Operating and maintenance	3,703	3,397	2,871
Recognition of regulatory assets	-	-	(4,900)
Depreciation, amortization, and decommissioning	1,709	1,735	1,497
Total operating expenses	10,431	9,733	3,962
Operating Income	2,108	1,970	7,118
Interest income	188	80	63
Interest expense	(738)	(583)	(797)
Other expense, net	(13)	(19)	(98)
Income Before Income Taxes	1,545	1,448	6,286
Income tax provision	554	544	2,466
Income From Continuing Operations	991	904	3,820
Discontinued Operations			
Gain on disposal of NEGT (net of income tax benefit of $13 million in 2005 and income tax expense of $374 million in 2004)	-	13	684
Net Income	$ 991	$ 917	$ 4,504
Weighted Average Common Shares Outstanding, Basic	346	372	398
Earnings Per Common Share from Continuing Operations, Basic	$ 2.78	$ 2.37	$ 9.16
Net Earnings Per Common Share, Basic	$ 2.78	$ 2.40	$ 10.80
Earnings Per Common Share from Continuing Operations, Diluted	$ 2.76	$ 2.34	$ 8.97
Net Earnings Per Common Share, Diluted	$ 2.76	$ 2.37	$ 10.57
Dividends Declared Per Common Share	$ 1.32	$ 1.23	$ -

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation
CONSOLIDATED BALANCE SHEETS
(in millions)

	Balance at December 31,	
	2006	**2005**
ASSETS		
Current Assets		
Cash and cash equivalents	$ 456	$ 713
Restricted cash	1,415	1,546
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $50 million in 2006 and $77 million in 2005)	2,343	2,422
Regulatory balancing accounts	607	727
Inventories:		
Gas stored underground and fuel oil	181	231
Materials and supplies	149	133
Income taxes receivable	-	21
Prepaid expenses and other	716	187
Total current assets	5,867	5,980
Property, Plant and Equipment		
Electric	24,036	22,482
Gas	9,115	8,794
Construction work in progress	1,047	738
Other	16	16
Total property, plant and equipment	34,214	32,030
Accumulated depreciation	(12,429)	(12,075)
Net property, plant and equipment	21,785	19,955
Other Noncurrent Assets		
Regulatory assets	4,902	5,578
Nuclear decommissioning funds	1,876	1,719
Other	373	842
Total other noncurrent assets	7,151	8,139
TOTAL ASSETS	$ 34,803	$ 34,074

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation
CONSOLIDATED BALANCE SHEETS
(in millions, except share amounts)

	Balance at December 31,	
	2006	**2005**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$ 759	$ 260
Long-term debt, classified as current	281	2
Rate reduction bonds, classified as current	290	290
Energy recovery bonds, classified as current	340	316
Accounts payable:		
Trade creditors	1,075	980
Disputed claims and customer refunds	1,709	1,733
Regulatory balancing accounts	1,030	840
Other	420	441
Interest payable	583	473
Income taxes payable	102	-
Deferred income taxes	148	181
Other	1,513	1,416
Total current liabilities	8,250	6,932
Noncurrent Liabilities		
Long-term debt	6,697	6,976
Rate reduction bonds	-	290
Energy recovery bonds	1,936	2,276
Regulatory liabilities	3,392	3,506
Asset retirement obligations	1,466	1,587
Deferred income taxes	2,840	3,092
Deferred tax credits	106	112
Other	2,053	1,833
Total noncurrent liabilities	18,490	19,672
Commitments and Contingencies (Notes 2, 4, 5, 6, 8, 9, 13, 15 and 17)		
Preferred Stock of Subsidiaries	252	252
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 372,803,521 common and 1,377,538 restricted shares in 2006 and issued 366,868,512 common and 1,399,990 restricted shares in 2005	5,877	5,827
Common stock held by subsidiary, at cost, 24,665,500 shares	(718)	(718)
Unearned compensation	-	(22)
Reinvested earnings	2,671	2,139
Accumulated other comprehensive loss	(19)	(8)
Total common shareholders' equity	7,811	7,218
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 34,803	$ 34,074

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year ended December 31,		
	2006	**2005**	**2004**
Cash Flows From Operating Activities			
Net income	$ 991	$ 917	$ 4,504
Gain on disposal of NEGT (net of income tax benefit of $13 million in 2005 and income tax expense of $374 million in 2004)	-	(13)	(684)
Net income from continuing operations	991	904	3,820
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, decommissioning and allowance for equity funds used during construction	1,756	1,698	1,497
Loss from retirement of long-term debt	-	-	65
Tax benefit from employee stock plans	-	50	41
Gain on sale of assets	(11)	-	(19)
Recognition of regulatory assets	-	-	(4,900)
Deferred income taxes and tax credits, net	(285)	(659)	2,607
Other deferred charges and noncurrent liabilities	151	33	(519)
Net effect of changes in operating assets and liabilities:			
Accounts receivable	130	(245)	(85)
Inventories	32	(60)	(12)
Accounts payable	17	257	273
Accrued taxes/income taxes receivable	124	(207)	(122)
Regulatory balancing accounts, net	329	254	(590)
Other current assets	(273)	29	760
Other current liabilities	(233)	273	(48)
Payments authorized by the Bankruptcy Court on amounts classified as liabilities subject to compromise	-	-	(1,022)
Other	(14)	82	110
Net cash provided by operating activities	2,714	2,409	1,856
Cash Flows From Investing Activities			
Capital expenditures	(2,402)	(1,804)	(1,559)
Net proceeds from sale of assets	17	39	35
Decrease (increase) in restricted cash	115	434	(1,216)
Proceeds from nuclear decommissioning trust sales	1,087	2,918	1,821
Purchases of nuclear decommissioning trust investments	(1,244)	(3,008)	(1,972)
Other	-	23	(27)
Net cash used in investing activities	(2,427)	(1,398)	(2,918)
Cash Flows From Financing Activities			
Borrowings under accounts receivable facility and working capital facility	350	260	300
Repayments under accounts receivable facility and working capital facility	(310)	(300)	-
Net issuance of commercial paper, net of discount of $2 million	458	-	-
Proceeds from issuance of long-term debt, net of issuance costs of $3 million in 2005 and $107 million in 2004	-	451	7,742
Proceeds from issuance of energy recovery bonds, net of issuance costs of $21 million in 2005	-	2,711	-
Long-term debt matured, redeemed or repurchased	-	(1,556)	(9,054)
Rate reduction bonds matured	(290)	(290)	(290)
Energy recovery bonds matured	(316)	(140)	-
Preferred stock with mandatory redemption provisions redeemed	-	(122)	(15)
Preferred stock without mandatory redemption provisions redeemed	-	(37)	-

Common stock issued	131	243	162
Common stock repurchased	(114)	(2,188)	(378)
Common stock dividends paid	(456)	(334)	-
Other	3	32	(91)
Net cash used in financing activities	(544)	(1,270)	(1,624)

Net change in cash and cash equivalents	(257)	(259)	(2,686)
Cash and cash equivalents at January 1	713	972	3,658
Cash and cash equivalents at December 31	$ 456	$ 713	$ 972
Supplemental disclosures of cash flow information			
Cash received for:			
Reorganization interest income	$ -	$ -	$ 16
Cash paid for:			
Interest (net of amounts capitalized)	503	403	646
Income taxes paid, net	736	1,392	128
Reorganization professional fees and expenses	-	-	61
Supplemental disclosures of noncash investing and financing activities			
Common stock dividends declared but not yet paid	$ 117	$ 115	$ -
Transfer of liabilities and other payables subject to compromise to operating assets and liabilities	-	-	(2,877)
Assumption of capital lease obligation	408	-	-
Transfer of Gateway Generating Station asset	69	-	-

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(in millions, except share amounts)

	Common Stock Shares	Common Stock Amount	Common Stock Held by Subsidiary	Unearned Compen-sation	Reinvested Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Total Common Share-holders' Equity	Comprehensive Income (Loss)
Balance at December 31, 2003	416,520,282	$ 6,468	$ (690)	$ (20)	$ (1,458)	$ (85)	$ 4,215	
Net income	-	-	-	-	4,504	-	4,504	$ 4,504
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133 (net of income tax expense of $2 million)	-	-	-	-	-	3	3	3
NEGT losses reclassified to earnings upon elimination of equity interest by PG&E Corporation (net of income tax expense of $43 million)	-	-	-	-	-	77	77	77
Other	-	-	-	-	-	1	1	1
Comprehensive income								$ 4,585
Common stock issued	8,410,058	162	-	-	-	-	162	
Common stock repurchased	(10,783,200)	(167)	-	-	(183)	-	(350)	
Common stock held by subsidiary	-	-	(28)	-	-	-	(28)	
Common stock warrants exercised	4,003,812	-	-	-	-	-	-	
Common restricted stock issued	498,910	16	-	(16)	-	-	-	
Common restricted stock cancelled	(33,721)	(1)	-	1	-	-	-	
Common restricted stock amortization	-	-	-	9	-	-	9	
Tax benefit from employee stock plans	-	41	-	-	-	-	41	
Other	-	(1)	-	-	-	-	(1)	
Balance at December 31, 2004	418,616,141	6,518	(718)	(26)	2,863	(4)	8,633	
Net income	-	-	-	-	917	-	917	917
Minimum pension liability adjustment (net of income tax benefit of $3 million)	-	-	-	-	-	(4)	(4)	(4)
Comprehensive income								$ 913
Common stock issued	10,264,535	247	-	-	-	-	247	
Common stock repurchased	(61,139,700)	(998)	-	-	(1,190)	-	(2,188)	

Common stock warrants exercised	295,919	-	-	-	-	-	-	
Common restricted stock issued	347,710	13	-	(13)	-	-	-	
Common restricted stock cancelled	(116,103)	(4)	-	4	-	-	-	
Common restricted stock amortization	-	-	-	13	-	-	13	
Common stock dividends declared and paid	-	-	-	-	(334)	-	(334)	
Common stock dividends declared but not yet paid	-	-	-	-	(115)	-	(115)	
Tax benefit from employee stock plans	-	50	-	-	-	-	50	
Other	-	1	-	-	(2)	-	(1)	
Balance at December 31, 2005	368,268,502	5,827	(718)	(22)	2,139	(8)	7,218	
Net income	-	-	-	-	991	-	991	$ 991
Comprehensive income								$ 991
Common stock issued	5,399,707	110	-	-	-	-	110	
ASR settlement of stock repurchased in 2005	-	(114)	-	-	-	-	(114)	
Common stock warrants exercised	51,890	-	-	-	-	-	-	
Common restricted stock, unearned compensation reversed in accordance with SFAS No. 123R	-	(22)	-	22	-	-	-	
Common restricted stock issued	566,255	21	-	-	-	-	21	
Common restricted stock cancelled	(105,295)	(1)	-	-	-	-	(1)	
Common restricted stock amortization	-	20	-	-	-	-	20	
Common stock dividends declared and paid	-	-	-	-	(342)	-	(342)	
Common stock dividends declared but not yet paid	-	-	-	-	(117)	-	(117)	
Tax benefit from employee stock plans	-	35	-	-	-	-	35	
Adoption of SFAS No. 158 (net of income tax benefit of $8 million)	-	-	-	-	-	(11)	(11)	
Other	-	1	-	-	-	-	1	
Balance at December 31, 2006	374,181,059	$ 5,877	$ (718)	$ -	$ 2,671	$ (19)	$ 7,811	

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company
CONSOLIDATED STATEMENTS OF INCOME
(in millions)

	Year ended December 31,		
	2006	**2005**	**2004**
Operating Revenues			
Electric	$ 8,752	$ 7,927	$ 7,867
Natural gas	3,787	3,777	3,213
Total operating revenues	12,539	11,704	11,080
Operating Expenses			
Cost of electricity	2,922	2,410	2,770
Cost of natural gas	2,097	2,191	1,724
Operating and maintenance	3,697	3,399	2,848
Recognition of regulatory assets	-	-	(4,900)
Depreciation, amortization and decommissioning	1,708	1,734	1,494
Total operating expenses	10,424	9,734	3,936
Operating Income	2,115	1,970	7,144
Interest income	175	76	50
Interest expense	(710)	(554)	(667)
Other income, net	7	16	16
Income Before Income Taxes	1,587	1,508	6,543
Income tax provision	602	574	2,561
Net Income	985	934	3,982
Preferred stock dividend requirement	14	16	21
Income Available for Common Stock	$ 971	$ 918	$ 3,961

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company
CONSOLIDATED BALANCE SHEETS
(in millions)

	Balance at December 31,	
	2006	**2005**
ASSETS		
Current Assets		
Cash and cash equivalents	$ 70	$ 463
Restricted cash	1,415	1,546
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $50 million in 2006 and $77 million in 2005)	2,343	2,422
Related parties	6	3
Regulatory balancing accounts	607	727
Inventories:		
Gas stored underground and fuel oil	181	231
Materials and supplies	149	133
Income taxes receivable	20	48
Prepaid expenses and other	714	183
Total current assets	5,505	5,756
Property, Plant and Equipment		
Electric	24,036	22,482
Gas	9,115	8,794
Construction work in progress	1,047	738
Total property, plant and equipment	34,198	32,014
Accumulated depreciation	(12,415)	(12,061)
Net property, plant and equipment	21,783	19,953
Other Noncurrent Assets		
Regulatory assets	4,902	5,578
Nuclear decommissioning funds	1,876	1,719
Related parties receivable	25	23
Other	280	754
Total other noncurrent assets	7,083	8,074
TOTAL ASSETS	$ 34,371	$ 33,783

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company
CONSOLIDATED BALANCE SHEETS
(in millions, except share amounts)

	Balance at December 31,	
	2006	**2005**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$ 759	$ 260
Long-term debt, classified as current	1	2
Rate reduction bonds, classified as current	290	290
Energy recovery bonds, classified as current	340	316
Accounts payable:		
Trade creditors	1,075	980
Disputed claims and customer refunds	1,709	1,733
Related parties	40	37
Regulatory balancing accounts	1,030	840
Other	402	423
Interest payable	570	460
Deferred income taxes	118	161
Other	1,346	1,255
Total current liabilities	7,680	6,757
Noncurrent Liabilities		
Long-term debt	6,697	6,696
Rate reduction bonds	-	290
Energy recovery bonds	1,936	2,276
Regulatory liabilities	3,392	3,506
Asset retirement obligations	1,466	1,587
Deferred income taxes	2,972	3,218
Deferred tax credits	106	112
Other	1,922	1,691
Total noncurrent liabilities	18,491	19,376
Commitments and Contingencies (Notes 2, 4, 5, 6, 8, 9, 13, 15 and 17)		
Shareholders' Equity		
Preferred stock without mandatory redemption provisions:		
Nonredeemable, 5.00% to 6.00%, outstanding 5,784,825 shares	145	145
Redeemable, 4.36% to 5.00%, outstanding 4,534,958 shares	113	113
Common stock, $5 par value, authorized 800,000,000 shares, issued 279,624,823 shares in 2006 and 2005	1,398	1,398
Common stock held by subsidiary, at cost, 19,481,213 shares	(475)	(475)
Additional paid-in capital	1,822	1,776
Reinvested earnings	5,213	4,702
Accumulated other comprehensive loss	(16)	(9)
Total shareholders' equity	8,200	7,650
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 34,371	$ 33,783

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year ended December 31,		
	2006	**2005**	**2004**
Cash Flows From Operating Activities			
Net income	$ 985	$ 934	$ 3,982
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, decommissioning and allowance for equity funds used during construction	1,755	1,697	1,494
Gain on sale of assets	(11)	-	-
Recognition of regulatory assets	-	-	(4,900)
Deferred income taxes and tax credits, net	(287)	(636)	2,580
Other deferred charges and noncurrent liabilities	116	21	(391)
Net effect of changes in operating assets and liabilities:			
Accounts receivable	128	(245)	(85)
Inventories	34	(60)	(12)
Accounts payable	21	257	273
Accrued taxes/income taxes receivable	28	(150)	52
Regulatory balancing accounts, net	329	254	(590)
Other current assets	(273)	2	55
Other current liabilities	(235)	273	395
Payments authorized by the Bankruptcy Court on amounts classified as liabilities subject to compromise	-	-	(1,022)
Other	(13)	19	7
Net cash provided by operating activities	2,577	2,366	1,838
Cash Flows From Investing Activities			
Capital expenditures	(2,402)	(1,803)	(1,559)
Net proceeds from sale of assets	17	39	35
Decrease (increase) in restricted cash	115	434	(1,577)
Proceeds from nuclear decommissioning trust sales	1,087	2,918	1,821
Purchases of nuclear decommissioning trust investments	(1,244)	(3,008)	(1,972)
Other	1	61	(27)
Net cash used in investing activities	(2,426)	(1,359)	(3,279)
Cash Flows From Financing Activities			
Borrowings under accounts receivable facility and working capital facility	350	260	300
Repayments under accounts receivable facility and working capital facility	(310)	(300)	-
Net issuance of commercial paper, net of discount of $2 million	458	-	-
Proceeds from issuance of long-term debt, net of issuance costs of $3 million in 2005 and $107 million in 2004	-	451	7,742
Proceeds from issuance of energy recovery bonds, net of issuance costs of $21 million in 2005	-	2,711	-
Long-term debt matured, redeemed or repurchased	-	(1,554)	(8,402)
Rate reduction bonds matured	(290)	(290)	(290)
Energy recovery bonds matured	(316)	(140)	-
Preferred stock dividends paid	(14)	(16)	(90)
Common stock dividends paid	(460)	(445)	-
Preferred stock with mandatory redemption provisions redeemed	-	(122)	(15)
Preferred stock without mandatory redemption provisions redeemed	-	(37)	-
Common stock repurchased	-	(1,910)	-
Other	38	65	-
Net cash used in financing activities	(544)	(1,327)	(755)

Net change in cash and cash equivalents	(393)	(320)	(2,196)
Cash and cash equivalents at January 1	463	783	2,979
Cash and cash equivalents at December 31	$ 70	$ 463	$ 783

Supplemental disclosures of cash flow information			
Cash received for:			
Reorganization interest income	$ -	$ -	$ 16
Cash paid for:			
Interest (net of amounts capitalized)	476	390	512
Income taxes paid, net	897	1,397	109
Reorganization professional fees and expenses	-	-	61
Supplemental disclosures of noncash investing and financing activities			
Transfer of liabilities and other payables subject to compromise to operating assets and liabilities	$ -	$ -	$ (2,877)
Equity contribution for settlement of plan of reorganization, or POR, payable	-	-	(129)
Assumption of capital lease obligation	408	-	-
Transfer of Gateway Generating Station asset	69	-	-

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(in millions)

	Preferred Stock Without Mandatory Redemption Provisions	Common Stock	Additional Paid-in Capital	Common Stock Held by Subsidiary	Reinvested Earnings	Accumu-lated Other Compre-hensive Income (Loss)	Total Share-holders' Equity	Comprehensive Income (Loss)
Balance at December 31, 2003	$ 294	$ 1,606	$ 1,964	$ (475)	$ 1,706	$ (6)	$ 5,089	
Net income	-	-	-	-	3,982	-	3,982	$ 3,982
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133 (net of income tax expense of $2 million)	-	-	-	-	-	3	3	3
Comprehensive income								$ 3,985
Equity contribution for settlement of POR payable (net of income taxes of $52 million)	-	-	77	-	-	-	77	
Preferred stock dividend	-	-	-	-	(21)	-	(21)	
Balance at December 31, 2004	294	1,606	2,041	(475)	5,667	(3)	9,130	
Net income	-	-	-	-	934	-	934	$ 934
Minimum pension liability adjustment (net of income tax benefit of $4 million)	-	-	-	-	-	(6)	(6)	(6)
Comprehensive income								$ 928
Common stock repurchased	-	(208)	(266)	-	(1,436)	-	(1,910)	
Common stock dividend	-	-	-	-	(445)	-	(445)	
Preferred stock redeemed	(36)	-	1	-	(2)	-	(37)	
Preferred stock dividend	-	-	-	-	(16)	-	(16)	
Balance at December 31, 2005	258	1,398	1,776	(475)	4,702	(9)	7,650	
Net income	-	-	-	-	985	-	985	$ 985
Minimum pension liability adjustment (net of income tax expense of $2 million)	-	-	-	-	-	3	3	3
Comprehensive income								$ 988

Tax benefit from employee stock plans	-	-	46	-	-	-	46
Common stock dividend	-	-	-	-	(460)	-	(460)
Preferred stock dividend	-	-	-	-	(14)	-	(14)
Adoption of SFAS No. 158 (net of income tax benefit of $7 million)	-	-	-	-	-	(10)	(10)
Balance at December 31, 2006	$ 258	$ 1,398	$ 1,822	$ (475)	$ 5,213	$ (16)	$ 8,200

See accompanying Notes to the Consolidated Financial Statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1: ORGANIZATION AND BASIS OF PRESENTATION

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

As discussed further in Note 15, on April 12, 2004, the Utility's plan of reorganization under the provisions of Chapter 11 of the U.S. Bankruptcy Code, or Chapter 11, became effective, and the Utility emerged from Chapter 11. The U.S. Bankruptcy Court for the Northern District of California, or Bankruptcy Court, which oversaw the Utility's Chapter 11 proceeding, retains jurisdiction, among other things, to resolve the remaining disputed Chapter 11 claims.

This is a combined annual report of PG&E Corporation and the Utility. Therefore, the Notes to the Consolidated Financial Statements apply to both PG&E Corporation and the Utility. PG&E Corporation's Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries. The Utility's 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 Consolidated Financial Statements.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America, or GAAP, requires management to make estimates and assumptions. These estimates and assumptions affect the reported amounts of revenues, expenses, assets and liabilities and the disclosure of contingencies and include, but are not limited to, estimates and assumptions used in determining the Utility's regulatory asset and liability balances based on probability assessments of regulatory recovery, revenues earned but not yet billed (including delayed billings), disputed claims, asset retirement obligations, allowance for doubtful accounts receivable, provisions for losses that are deemed probable from environmental remediation liabilities, pension liabilities, severance costs, 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, the fair value of financial instruments, and the Utility's assessment of 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 involving a wide range of factors, including future regulatory decisions and economic conditions that are difficult to predict, actual results could differ from these estimates. PG&E Corporation's and the Utility's Consolidated Financial Statements reflect all adjustments that management believes are necessary for the fair presentation of their financial position and results of operations for the periods presented.

NOTE 2: 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 CPUC and the FERC.

Cash and Cash Equivalents

Invested cash and other short-term investments with original maturities of three months or less are considered cash equivalents. Cash equivalents are stated at cost, which approximates fair value. 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.

PG&E Corporation had four account balances with institutional money market funds that were each greater than 10% of PG&E Corporation's and the Utility's total cash and cash equivalents balance at December 31, 2006.

Restricted Cash

Restricted cash includes Utility amounts held in escrow pending the resolution of remaining disputed Chapter 11 claims and collateral required by the California Independent System Operator, or CAISO, the State of California and other counterparties. The Utility also provides deposits to counterparties in the normal course of operations and under certain third party agreements.

Allowance for Doubtful Accounts Receivable

PG&E Corporation and the Utility recognize an allowance for doubtful accounts to record accounts receivable at estimated

net realizable value. The allowance is determined based upon a variety of factors, including historical write-off experience, delinquency rates, current economic conditions and assessment of customer collectibility. If circumstances require changes in the Utility's assumptions, allowance estimates are adjusted accordingly. The customer accounts receivable write-offs are recovered in rates, but limited to amounts approved by the CPUC, with any excess being borne by shareholders. In 2006 there was no significant impact to the shareholders.

Inventories

Inventories are valued at average cost and include materials, supplies and gas stored underground. Materials and supplies are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, when installed. Materials reserves are made for obsolete inventory. Gas stored underground is charged to inventory at current costs when purchased and then expensed at average costs when distributed to customers.

Property, Plant and Equipment

Property, plant and equipment are reported at their original cost. Original cost includes:

- Labor and materials;
- Construction overhead; and
- Allowance for funds used during construction, or AFUDC.

AFUDC

AFUDC is the estimated cost of debt and equity used to finance regulated plant additions that can be recorded as part of the cost of construction projects. AFUDC is recoverable from customers through rates over the life of the related property once the property is placed in service. The Utility recorded AFUDC of approximately $47 million and $20 million related to equity and debt, respectively, during 2006, $37 million and $14 million related to equity and debt, respectively, during 2005, and $20 million and $12 million related to equity and debt, respectively, during 2004. PG&E Corporation on a stand-alone basis did not have any capitalized interest or AFUDC in 2006, 2005 and 2004.

Depreciation

The Utility's composite depreciation rate was 3.09% in 2006, 3.28% in 2005 and 3.42% in 2004.

(in millions)	Gross Plant As of December 31, 2006	Estimated Useful Lives
Electricity generating facilities	$ 2,068	15 to 44 years
Electricity distribution facilities	15,305	16 to 58 years
Electricity transmission	4,397	40 to 70 years
Natural gas distribution facilities	5,028	23 to 54 years
Natural gas transportation	3,016	25 to 45 years
Natural gas storage	48	25 to 48 years
Other	3,289	5 to 40 years
Total	$ 33,151	

The useful lives of the Utility's property, plant and equipment are authorized by the CPUC and the FERC and depreciation expense is included within the recoverable costs of service included in rates charged to customers. Depreciation expense includes a component for the original cost of assets and a component for estimated future removal and remediation costs, net of any salvage value at retirement. The Utility has a separate rate it collects from customers for the accrual of its recorded obligation for nuclear decommissioning that is included in depreciation, amortization and decommissioning expense in the accompanying Consolidated Statements of Income.

PG&E Corporation and the Utility charge the original cost of retired plant less salvage value to accumulated depreciation upon retirement of plant in service in accordance with SFAS No. 71 “Accounting for the Effects of Certain Types of Regulation” as amended, or SFAS No. 71. PG&E Corporation and the Utility expense repair and maintenance costs as incurred.

Nuclear Fuel

Property, plant and equipment also includes nuclear fuel inventories. Stored nuclear fuel inventory is stated at weighted average cost. Nuclear fuel in the reactor is expensed as used based on the amount of energy output.

Capitalized Software Costs

PG&E Corporation and the Utility account for internal software in accordance with Statement of Position, “Accounting for the Costs of Computer Software Developed or Obtained for Internal Use”, or SOP 98-1.

Under SOP 98-1, PG&E Corporation and the Utility capitalize costs incurred during the application development stage of internal use software projects to property, plant and equipment. Capitalized software costs totaled $237 million at December 31, 2006 and $201 million at December 31, 2005, net of accumulated amortization of approximately $197 million at December 31, 2006 and $168 million at December 31, 2005. PG&E Corporation and the Utility expense capitalized software costs ratably over the expected lives of the software ranging from 3 to 15 years, commencing upon operational use.

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. SFAS No. 71 applies to regulated entities whose rates are designed to recover the costs of providing service. SFAS No. 71 applies to all of the Utility's operations.

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

To the extent that portions of the Utility's operations cease to be subject to SFAS No. 71 or recovery is no longer probable as a result of changes in regulation or other reasons, the related regulatory assets and liabilities are written off. No such write-offs took place in 2006, 2005, and 2004.

Other Intangible Assets

Other intangible assets consist of hydroelectric facility licenses and other agreements, with lives ranging from 19 to 40 years. The gross carrying amount of the hydroelectric facility licenses and other agreements was approximately $73 million at December 31, 2006 and December 31, 2005. The accumulated amortization was approximately $28 million at December 31, 2006 and $25 million at December 31, 2005.

The Utility's amortization expense related to intangible assets was approximately $3 million in 2006, $3 million in 2005 and $4 million in 2004. The estimated annual amortization expense based on the December 31, 2006 intangible asset balance for the Utility's intangible assets for 2007 through 2011 is approximately $3 million each year. Intangible assets are recorded to Other Noncurrent Assets on the Consolidated Balance Sheets.

Investments in Affiliates

The Utility has investments in unconsolidated affiliates, which are mainly limited partnerships engaged in the purchase of low-income residential real estate property. The equity method of accounting is applied to the Utility's investment in these partnerships. Under the equity method, the Utility's share of equity income or losses of these partnerships is reflected as other operating income or expense in its Consolidated Statements of Income. As of December 31, 2006, the Utility's recorded investment in these entities totaled approximately $4 million. As a limited partner, the Utility's exposure to potential loss is limited to its investment in each partnership.

Consolidation of Variable Interest Entities

The Financial Accounting Standards Board, or FASB, Interpretation No. 46 (revised December 2003), "Consolidation of Variable Interest Entities," or FIN 46R, provides that 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. FIN 46R requires that the holder subject to a majority of the risk of loss from a VIE's activities must consolidate the VIE. However, if

no holder has a majority of the risk of loss, then a holder entitled to receive a majority of the entity's residual returns would consolidate the entity. In accordance with FIN 46R, the Utility consolidated the assets, liabilities and non-controlling interests of a low-income housing partnership that was determined to be a VIE under FIN 46R. The impact of the VIE was immaterial to the Consolidated Financial Statements and operations of PG&E Corporation and the Utility.

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 or more plants that sell substantially all of their output to the Utility, and the contract price for power is correlated with the plant's variable costs of production. As of December 31, 2006, the Utility did not have any power purchase agreements meeting these criteria.

Impairment of Long-Lived Assets

The carrying values of long-lived assets are evaluated in accordance with the provisions of SFAS No. 144, “Accounting for the Impairment of Long Lived Assets,” or SFAS No. 144. In accordance with SFAS No. 144, PG&E Corporation and the Utility evaluate the carrying amounts of long-lived assets for impairment whenever events occur or circumstances change that may affect the recoverability or the estimated life of long-lived assets.

Asset Retirement Obligations

PG&E Corporation and the Utility account for asset retirement obligations in accordance with SFAS No. 143, "Accounting for Asset Retirement Obligations," or SFAS No. 143, and FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations - an Interpretation of FASB Statement No. 143" or FIN 47. 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. In each subsequent period, the liability is accreted to its present value; and the capitalized cost is depreciated over the useful life of the 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. FIN 47 clarifies that if a legal obligation to perform an asset retirement obligation exists but performance is conditional upon a future event, and the obligation can be reasonably estimated, then a liability should be recognized in accordance with SFAS No. 143.

The Utility has also identified its nuclear generation and certain fossil fuel generation facilities as having asset retirement obligations under SFAS No. 143. In accordance with FIN 47, the Utility recognized asset retirement obligations related to asbestos contamination in buildings, potential site restoration at certain hydroelectric facilities, fuel storage tanks and contractual obligations to restore leased property to pre-lease condition. Additionally, the Utility recognized asset retirement obligations related to the California Gas Transmission pipeline, Gas Distribution, Electric Distribution and Electric Transmission system assets.

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

(in millions)	
ARO liability at December 31, 2004	$ 1,301
Recognition of FIN 47 obligation	203
Accretion expense	85
Liabilities settled	(2)
ARO liability at December 31, 2005	1,587
Revision in estimated cash flows	(204)
Accretion expense	98
Liabilities settled	(15)
ARO liability at December 31, 2006	$ 1,466

The Utility has identified additional asset retirement obligations for which a reasonable estimate of fair value could not be made. The Utility has not recognized a liability related to these additional obligations which include: obligations to restore land to its pre-use condition under the terms of certain land rights agreements, removal and proper disposal of lead-based paint contained in some PG&E facilities, removal of certain communications equipment from leased property and retirement activities associated with substation and certain hydroelectric facilities. The Utility was not able to reasonably estimate the asset retirement obligation associated with these assets because the settlement date of the obligation was indeterminate and information sufficient to reasonably estimate the settlement date or range of settlement dates does not exist. Land rights, communication equipment leases and substation facilities will be maintained for the foreseeable future, and the Utility cannot reasonably estimate the settlement date or range of settlement dates for the obligations associated with these assets. The Utility does not have

information available that specifies which facilities contain lead-based paint and therefore cannot reasonably estimate the settlement date(s) associated with the obligation. The

Utility will maintain and continue to operate its hydroelectric facilities until operation of a facility therefore becomes uneconomic. The operation of the majority of the Utility's hydroelectric facilities is currently and for the foreseeable future economic, and the settlement date cannot be determined at this time.

Fair Value of Financial Instruments

The fair value of a financial instrument represents the amount at which the instrument could be exchanged in a current transaction between willing parties, other than in a forced sale or liquidation. The fair value may be significantly different than the carrying amount of financial instruments that are recorded at historical amounts.

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

- The fair values of cash and cash equivalents, restricted cash and deposits, net accounts receivable, price risk management assets and liabilities, short-term borrowings, accounts payable, customer deposits and the Utility's variable rate pollution control bond loan agreements approximate their carrying values as of December 31, 2006 and 2005; and

- The fair values of the Utility's fixed rate senior notes and fixed rate pollution control bond loan agreements, PG&E Funding, LLC's rate reduction bonds, PG&E Energy Recovery Funding, LLC's energy recovery bonds, or ERBs, and PG&E Corporation's 9.50% Convertible Subordinated Notes, were based on quoted market prices obtained from the Bloomberg financial information system at December 31, 2006.

The carrying amount and fair value of PG&E Corporation's and the Utility's financial instruments are as follows (the table below excludes financial instruments with fair values that approximate their carrying values, as these instruments are presented at their carrying value in the Consolidated Balance Sheets):

	At December 31,			
	2006		2005	
(in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Debt (Note 4):				
PG&E Corporation	$ 280	$ 937	$ 280	$ 783
Utility	5,629	5,616	5,628	5,720
Rate reduction bonds (Note 5)	290	292	580	591
Energy recovery bonds (Note 6)	2,276	2,239	2,592	2,558

Gains and Losses on Debt Extinguishments

Gains and losses on debt extinguishments associated with regulated operations that are subject to the provisions of SFAS No. 71 are deferred and amortized over the remaining original amortization period of the debt reacquired, consistent with recovery of costs through regulated rates. Gains and losses on debt extinguishments associated with unregulated operations are fully recognized at the time such debt is reacquired and are reported as a component of interest expense.

Accumulated Other Comprehensive Income (Loss)

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

	Hedging Transactions in Accordance with SFAS No. 133	Foreign Currency Translation Adjustment	Minimum Pension Liability Adjustment	Adoption of SFAS No. 158	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
NEGT losses reclassified to earnings upon elimination of equity interest by PG&E Corporation	77	-	-	-	-	77
Other	-	-	-	-	1	1
Balance at December 31, 2004	(1)	-	(4)	-	1	(4)
Period change in:						
Minimum pension liability adjustment	-	-	(4)	-	-	(4)
Other	1	-	-	-	(1)	-
Balance at December 31, 2005	-	-	(8)	-	-	(8)
Period change in:						
Adoption of SFAS No. 158	-	-	8	(19)	-	(11)
Balance at December 31, 2006	$ -	$ -	$ -	$ (19)	$ -	$ (19)

Accumulated other comprehensive income (loss) included losses related to discontinued operations recognized in connection with PG&E Corporation's cancellation of its equity interest in National Energy & Gas Transmission, Inc., or NEGT, of approximately $77 million at December 31, 2004. Excluding the activity related to NEGT, there was no material difference between PG&E Corporation’s and the Utility’s accumulated other comprehensive income (loss) for the periods presented above.

Revenue Recognition

Electricity revenues, which are comprised of revenue from generation, transmission and distribution services, are billed to the Utility's customers at the CPUC-approved "bundled" electricity rate. The “bundled” electricity rate also includes the rate component set by the FERC for electric transmission services. Natural gas revenues, which are comprised of transmission and distribution services, are also billed at CPUC-approved rates. The Utility's revenues are recognized as electricity and natural gas are delivered, and include amounts for services rendered but not yet billed at the end of each year.

As further discussed in Note 17, in January 2001, the California Department of Water Resources, or DWR, began purchasing electricity to meet the portion of demand of the California investor-owned electric utilities that was not being satisfied from their own generation facilities and existing electricity contracts. Under California law, the DWR is deemed to sell the electricity directly to the Utility's retail customers, not to the Utility. The Utility acts as a pass-through entity for electricity purchased by the DWR on behalf of its customers. Although charges for electricity provided by the DWR are included in the amounts the Utility bills its customers, the Utility deducts the amounts passed through to the DWR from its electricity revenues. The pass-through amounts are based on the quantities of electricity provided by the DWR that are consumed by customers at the CPUC-approved remittance rate. These pass-through amounts are excluded from the Utility's electricity revenues in its Consolidated Statements of Income.

Earnings Per Share

PG&E Corporation applies the treasury stock method of reflecting the dilutive effect of outstanding stock-based compensation in the calculation of diluted earnings per common share, or EPS, in accordance with SFAS No. 128, "Earnings Per Share," or SFAS No. 128. Under SFAS No. 128, PG&E Corporation is required to assume that shares underlying stock options, other stock-based compensation and warrants are issued and that the proceeds received by PG&E Corporation from the exercise of these options and warrants are assumed to be used to purchase common shares at the average market price during the reported period. The incremental shares, the difference between the number of shares assumed to have been issued upon exercise and the number of shares assumed to have been purchased, is included in weighted average common shares outstanding for the purpose of calculating diluted EPS.

Income Taxes

PG&E Corporation and the Utility use the liability method of accounting for income taxes. Income tax expense (benefit) includes current and deferred income taxes resulting from operations during the year. Investment tax credits are amortized over the life of the related property. Other tax credits, mainly synthetic fuel tax credits, are recognized in income as earned.

PG&E Corporation files a consolidated U.S. federal income tax return that includes domestic subsidiaries in which its ownership is 80% or more. In addition, PG&E Corporation files combined state income tax returns where applicable. PG&E Corporation and the Utility are parties to a tax-sharing arrangement under which the Utility determines its income tax provision (benefit) on a stand-alone basis.

Prior to July 8, 2003, the date that PG&E Corporation's former subsidiary, NEGT, filed a Chapter 11 petition, PG&E Corporation applied the liability method to recognize federal income tax benefits related to the losses of NEGT and its subsidiaries for financial statement purposes. After July 7, 2003, PG&E Corporation applied the cost method of accounting with respect to the losses of NEGT and its subsidiaries and has not recognized additional income tax benefits in its financial statements. PG&E Corporation was required to continue to include NEGT and its subsidiaries in its consolidated income tax returns covering all periods through October 29, 2004, the effective date of NEGT's plan of reorganization and the cancellation of PG&E Corporation's equity ownership in NEGT. See Note 11 of the Notes to the Consolidated Financial Statements for further discussion.

Accounting for Derivatives and Hedging Activities

The Utility engages in price risk management activities to manage its exposure to fluctuations in commodity prices and interest rates in its non-trading portfolio. Price risk management activities involve entering into contracts to procure electricity, natural gas, nuclear fuel and firm transmission rights for electricity.

The Utility uses a variety of derivative instruments, such as physical forwards and options, exchange traded futures and options, commodity swaps, firm transmission rights for electricity and other contracts. Derivative instruments are recorded on PG&E Corporation's and the Utility's Consolidated Balance Sheets at fair value. Changes in the fair value of derivative instruments are recorded in earnings, or to the extent they are recoverable through regulated rates, are deferred and recorded in regulatory accounts. Derivative instruments may be designated as cash flow hedges when they are entered into to hedge variable price risk associated with the purchase of commodities. For cash flow hedges, fair value changes are deferred in accumulated other comprehensive income and recognized in earnings as the hedged transactions occur, unless they are recovered in rates, in which case, they are recorded in a regulatory balancing account. Derivative instruments are presented in other current and noncurrent assets or other current and noncurrent liabilities unless they meet certain exemptions.

In order for a derivative instrument to be designated as a cash flow hedge, the relationship between the derivative instrument and the hedged item or transaction must be highly effective. The effectiveness test is performed at the inception of the hedge and each reporting period thereafter, throughout the period that the hedge is designated as such. Unrealized gains and losses related to the effective and ineffective portions of the change in the fair value of the derivative instrument, to the extent they are recoverable through rates, are deferred and recorded in regulatory accounts.

Cash flow hedge accounting is discontinued prospectively if it is determined that the derivative instrument no longer qualifies as an effective hedge, or when the forecasted transaction is no longer probable of occurring. If cash flow hedge accounting is discontinued, the derivative instrument continues to be reflected at fair value, with any subsequent changes in fair value recognized immediately in earnings. Gains and losses previously recorded in accumulated other comprehensive income (loss) will remain there until the hedged item is recognized in earnings, unless the forecasted transaction is probable of not occurring, in which case the gains and losses from the derivative instrument will be immediately recognized in earnings. A hedged item is recognized in earnings when it matures or is exercised. Any gains and losses that would have been recognized in earnings or deferred in accumulated other comprehensive income (loss), to the extent they are recoverable through rates, are deferred and recorded in regulatory accounts.

Net realized and unrealized gains or losses on derivative instruments are included in various items on PG&E Corporation's and the Utility's Consolidated Statements of Income, including cost of electricity and cost of natural gas. Cash inflows and outflows associated with the settlement of price risk management activities are recognized in operating cash flows on PG&E Corporation's and the Utility's Consolidated Statements of Cash Flows.

The fair value of contracts is estimated using the mid-point of quoted bid and ask forward prices, including quotes from counterparties, brokers, electronic exchanges and published indices, supplemented by online price information from news services. When market data is not available, proprietary models are used to estimate fair value.

The Utility has derivative instruments for the physical delivery of commodities transacted in the normal course of business as well as non-financial assets that are not exchange-traded. These derivative instruments are eligible for the normal purchase and sales and non-exchange traded contract exceptions under SFAS No. 133, and are not reflected on the balance sheet at fair value. They are

recorded and recognized in income using accrual accounting. Therefore, expenses are recognized as incurred.

The Utility has certain commodity contracts for the purchase of nuclear fuel and core gas transportation and storage contracts that are not derivative instruments and are not reflected on the balance sheet at fair value. Expenses are recognized as incurred.

See Note 12 of the Notes to the Consolidated Financial Statements.

Adoption of New Accounting Pronouncements

Variable Interest Entities

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

Share-Based Payment

On January 1, 2006, PG&E Corporation and the Utility adopted the provisions of SFAS No. 123R, “Share-Based Payment,” or SFAS No. 123R, using the modified prospective application method which requires that compensation cost be recognized for all share-based payment awards, including unvested stock options, based on the grant-date fair value. SFAS No. 123R requires that an estimate of future forfeitures be made and that compensation cost be recognized only for share-based payment awards that are expected to vest. Prior to January 1, 2006, PG&E Corporation and the Utility accounted for share-based payment awards, such as stock options, restricted stock and other share-based incentive awards, under the recognition and measurement provisions of Accounting Principles Board, or APB, Opinion No. 25, “Accounting for Stock Issued to Employees,” or Opinion 25, as permitted by SFAS No. 123, “Accounting for Stock-Based Compensation,” or SFAS No. 123. Under the provisions of Opinion 25, PG&E Corporation and the Utility did not recognize compensation cost for stock options for periods prior to January 1, 2006, because the exercise prices of all stock options were equal to the market value of the underlying common stock on the date of grant of the options.

For 2006, PG&E Corporation’s and the Utility’s operating income, income before income taxes, net income, and basic and diluted EPS were lower under SFAS No. 123R than if they had continued to account for share-based payments under Opinion 25. The following table shows the reduction in these items as a result of the adoption of SFAS No. 123R:

(in millions except per share amounts)	PG&E Corporation Year Ended December 31, 2006	Utility Year Ended December 31, 2006
Operating Income	$ (18)	$ (13)
Income Before Income Taxes	(18)	(13)
Net Income	(11)	(8)
Earnings Per Common Share, Basic	$ (0.04)	
Earnings Per Common Share, Diluted	$ (0.04)	

The impact on net income for 2006 is primarily attributed to the prospective application of accounting for share-based payment awards with terms that accelerate vesting on retirement and expense recognition of previously unvested stock options.

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

Prior to the adoption of SFAS No. 123R, PG&E Corporation and the Utility presented all tax benefits from share-based payment awards as operating cash flows in the Consolidated Statements of Cash Flows. SFAS No. 123R requires that cash flows from the tax benefits resulting from tax deductions in excess of the compensation cost recognized for those awards (excess tax benefits) be classified as financing cash flows. PG&E Corporation's and the Utility's excess tax benefit of $35 million and $46

million, respectively, would have been classified as an operating cash inflow if PG&E Corporation and the Utility had not adopted SFAS No. 123R (see Note 14 for further discussion of share-based compensation).

The tables below show the effect on PG&E Corporation's net income and EPS if PG&E Corporation and the Utility had elected to account for stock-based compensation using the fair-value method under SFAS No. 123 based on the valuation assumptions disclosed in Note 14, for the years ended December 31, 2005 and 2004:

	Year ended December 31,	
	2005	2004
(in millions, except per share amounts)		
Net earnings:		
As reported	$ 917	$ 4,504
Deduct: Incremental stock-based employee compensation expense determined under the fair value based method for all awards, net of related tax effects	(12)	(14)
Pro forma	$ 905	$ 4,490
Basic earnings per share:		
As reported	$ 2.40	$ 10.80
Pro forma	2.37	10.77
Diluted earnings per share:		
As reported	2.37	10.57
Pro forma	2.33	10.59

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:

	Year ended December 31,	
	2005	2004
(in millions)		
Net earnings:		
As reported	$ 918	$ 3,961
Deduct: Incremental stock-based employee compensation expense determined under the fair value based method for all awards, net of related tax effects	(7)	(8)
Pro forma	$ 911	$ 3,953

Accounting Changes and Error Corrections

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

Changes in Accounting for Certain Derivative Contracts

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

Accounting for Defined Benefit Pensions and Other Postretirement Plans

On December 31, 2006, PG&E Corporation and the Utility adopted SFAS No. 158, "Employers' Accounting for Defined

Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)," or SFAS No. 158. SFAS No. 158 requires the funded status of an entity's plans to be recognized on the balance sheet, eliminates the additional minimum liability, and enhances related disclosure requirements. The funded status of a plan, as measured under SFAS No. 158, is the difference between the fair value of plan assets and the projected benefit obligation for a pension plan and the accumulated postretirement benefit obligation for other postretirement benefit plans. SFAS No. 158 also requires an entity to measure the funded status of a plan as of the date of its year-end balance sheet; PG&E Corporation and the Utility use a December 31 measurement date and therefore no adjustments are needed to comply with this requirement of SFAS No. 158. SFAS No. 158 does not change the method of recording expense on the statement of income; therefore, the effects of adopting SFAS No. 158 did not have an impact on earnings or on cash flows.

Upon adoption of SFAS No. 158, PG&E Corporation and the Utility recorded a net benefit liability equal to the underfunded status of certain pension and other postretirement benefit plans at December 31, 2006 in the amounts of $124 million and $83 million, respectively. In addition, PG&E Corporation and the Utility recorded a net pension benefit asset equal to the overfunded status of certain pension plans in the amount of $34 million at December 31, 2006. On December 31, 2006, the unrecognized prior service costs, unrecognized gains and losses, and unrecognized net transition obligations were recognized as components of accumulated other comprehensive income, net of tax (see Note 14 for further discussion). At December 31, 2006, PG&E Corporation's and the Utility's accumulated other comprehensive income included losses of approximately $19 million and $16 million, respectively, related to pensions and other postretirement benefits.

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. 87 and costs recovered through the ratemaking process. As a result of the adoption of SFAS No. 158, the Utility reduced the existing pension regulatory liability by approximately $574 million related to the defined benefit pension plan for amounts that would otherwise be charged to accumulated other comprehensive income under SFAS No. 158. At December 31, 2006 the Utility has a net regulatory liability of approximately $23 million. The Utility has not recorded a regulatory asset for the SFAS No. 158 charge related to the other postretirement plans as a result of its funding approach and rate recovery method. The expenses associated with these plans are accounted for under SFAS No. 106, and rate recovery is based on the lesser of the SFAS No. 106 expense or the annual tax-deductible contributions to the appropriate trusts.

Accounting Pronouncements Issued But Not Yet Adopted

Accounting for Uncertainty in Income Taxes

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

Fair Value Measurements

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements," or SFAS No. 157. SFAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. SFAS No. 157 also establishes a framework for measuring fair value and provides for expanded disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. PG&E Corporation and the Utility are currently evaluating the impact of SFAS No. 157.

Fair Value Option

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities," or SFAS No. 159. SFAS No. 159 establishes a fair value option under which entities can elect to report certain financial asset and liabilities at fair value, with changes in fair value recognized in earnings. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. PG&E Corporation and the Utility are currently evaluating the impact of SFAS No. 159.

NOTE 3: REGULATORY ASSETS, LIABILITIES AND BALANCING ACCOUNTS

Regulatory Assets

As discussed in Note 2, PG&E Corporation and the Utility account for the financial effects of regulation in accordance with

SFAS No. 71. Long term regulatory assets are comprised of the following:

	Balance at December 31,	
	2006	2005
(in millions)		
Energy recovery bond regulatory asset	$ 2,170	$ 2,509
Utility retained generation regulatory assets	1,018	1,099
Regulatory assets for deferred income tax	599	536
Environmental compliance costs	303	310
Unamortized loss, net of gain, on reacquired debt	295	321
Regulatory assets associated with plan of reorganization	147	163
Post-transition period contract termination costs	120	131
Scheduling coordinator costs	111	-
Rate reduction bond regulatory asset	-	456
Other	139	53
Total regulatory assets	$ 4,902	$ 5,578

The ERB represents refinancing of the settlement regulatory asset established under the December 19, 2003 settlement agreement among PG&E Corporation, the Utility and the CPUC to resolve the Utility's Chapter 11 proceeding, or the Chapter 11 Settlement Agreement. During 2006, the Utility recorded amortization of the ERB regulatory asset of approximately $339 million and expects to fully recover this asset by the end of 2012.

As a result of the Chapter 11 Settlement Agreement, the Utility recognized a one-time non-cash gain of $1.2 billion, pre-tax ($0.7 billion, after-tax), for the Utility's retained generation regulatory assets in the first quarter of 2004. The individual components of these regulatory assets will be amortized over their respective lives, with a weighted average life of approximately 16 years. During 2006, the Utility recorded amortization of the Utility's retained generation regulatory assets of approximately $81 million.

The regulatory assets for deferred income tax represent deferred income tax benefits passed through to customers and are offset by deferred income tax liabilities. Tax benefits to customers have been passed through as the CPUC requires utilities under its jurisdiction to follow the "flow through" method of passing certain tax benefits to customers. The "flow through" method ignores the effect of deferred taxes on rates. Based on current regulatory ratemaking and income tax laws, the Utility expects to recover deferred income tax related to regulatory assets over periods ranging from 1 to 40 years.

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

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

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 Utility expects to recover these costs over periods ranging from 5 to 30 years .

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

The regulatory asset related to scheduling coordinator, or SC, costs represents costs that the Utility incurred beginning in 1998 in its capacity as a scheduling coordinator for its existing wholesale transmission customers. The Utility expects to fully recover the SC costs by 2009.

Rate reduction bond, or RRB, regulatory assets represent electric industry restructuring costs that the Utility expects to collect over the term of the RRBs. During the year ended December 31, 2006, the Utility recorded amortization of the RRB regulatory asset of approximately $266 million. The remaining balance is included in current regulatory assets as the RRBs are scheduled to mature December 26, 2007. The Utility expects to fully recover the RRB regulatory asset by the end of 2007.

Finally, as of December 31, 2006, “Other,” is primarily related to price risk management contracts entered into by the Utility to procure electricity and natural gas to reduce commodity price risks, which are accounted for as derivatives under SFAS No. 133. The costs and proceeds of these derivative instruments are recovered or refunded in regulated rates charged to customers. At December 31, 2005, the balance of “Other” consisted primarily of asset retirement obligation costs (see further discussion below) and vegetation management costs.

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

Current Regulatory Assets

As of December 31, 2006, the Utility had current regulatory assets of approximately $434 million, consisting primarily of the current portion of the RRB regulatory asset and price risk management contracts. These amounts are included in Prepaid Expenses and Other on the Consolidated Balance Sheets. At December 31, 2005, the amount of current regulatory assets was immaterial.

Regulatory Liabilities

Long term regulatory liabilities are comprised of the following:

	Balance at December 31,	
	2006	**2005**
(in millions)		
Cost of removal obligation	$ 2,340	$ 2,141
Asset retirement costs	608	538
Public purpose programs	169	154
Price risk management	37	213
Employee benefit plans	23	195
Rate reduction bond regulatory liability	-	157
Other	215	108
Total regulatory liabilities	$ 3,392	$ 3,506

Cost of removal represents revenues collected for asset removal costs that the Utility expects to incur in the future. Asset retirement costs represent timing differences between the recognition of asset retirement obligations and the amounts recognized for ratemaking purposes in accordance with GAAP under SFAS No. 143 and FIN 47, as applied to rate-regulated entities. Public purpose programs represents revenues designated for public purpose program costs that are expected to be incurred in the future. Price risk management represents contracts entered into by the Utility to procure electricity and natural gas that are accounted for as derivative instruments under SFAS No. 133. Additionally, the Utility hedges natural gas in the electric and natural gas portfolios on behalf of its customers to reduce commodity price risk. The costs and proceeds of these derivatives are recovered in regulated rates charged to customers. 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. Rate reduction bonds, or RRBs, represent the deferral of over-collected revenue associated with the RRBs that the Utility expects to return to customers in the future. Finally, as of December 31, 2006, “Other” regulatory liabilities are primarily related to hazardous substance insurance recoveries and the Gateway Generating Station, or Gateway, which was acquired as part of a settlement with Mirant Corporation. The liability related to Gateway will be amortized over 30 years beginning March 2009.

Current Regulatory Liabilities

As of December 31, 2006, the Utility had current regulatory liabilities of approximately $309 million, consisting primarily of electric transmission wheeling revenue refunds and the RRB regulatory liability. These amounts are included in Other Current Liabilities on the Consolidated Balance Sheets. The Utility had current regulatory liabilities of $157 million, primarily comprised of price risk management activities, at December 31, 2005.

Regulatory Balancing Accounts

The Utility’s regulatory balancing accounts are used as a mechanism for the Utility to recover amounts incurred for certain costs, primarily commodity costs. Sales balancing accounts accumulate differences between revenues and the Utility's authorized revenue

requirements. Cost balancing accounts accumulate differences between incurred costs and authorized revenue requirements. The Utility also obtained CPUC approval for balancing account treatment of variances between forecasted and actual commodity costs

and volumes. This approval results in eliminating the earnings impact from any throughput and revenue variances from adopted forecast levels. Under-collections that are probable of recovery through regulated rates are recorded as regulatory balancing account assets. Over-collections that are probable of being credited to customers are recorded as regulatory balancing account liabilities.

The Utility's current regulatory balancing accounts accumulate balances until they are refunded to or received from the Utility's customers through authorized rate adjustments 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 noncurrent regulatory assets and liabilities. The CPUC does not allow the Utility to offset regulatory balancing account assets against balancing account liabilities.

Regulatory Balancing Account Assets

	Balance at December 31,	
	2006	**2005**
(in millions)		
Electricity revenue and cost balancing accounts	$ 501	$ 568
Natural gas revenue and cost balancing accounts	106	159
Total	$ 607	$ 727

Regulatory Balancing Account Liabilities

	Balance at December 31,	
	2006	**2005**
(in millions)		
Electricity revenue and cost balancing accounts	$ 951	$ 827
Natural gas revenue and cost balancing accounts	79	13
Total	$ 1,030	$ 840

During 2006, the under-collection in the Utility’s electricity revenue and cost balancing account assets decreased from 2005 mainly due to regulatory decisions allowing the Utility to recover certain costs through customer rates. These amounts did not have authorized rate components in 2005, thus resulting in an under-collection. The increase in the over-collected position of the Utility’s electricity revenue and cost balancing account liabilities between 2005 and 2006 was attributable to lower procurement costs as compared to forecasted procurement costs.

During 2006, the under-collection in the Utility’s natural gas revenue and cost balancing account assets decreased and the over-collection in balancing account liabilities increased from 2005 due mainly to decreasing gas costs as compared to the approved revenue requirements.

NOTE 4: DEBT

Long-Term Debt

The following table summarizes PG&E Corporation's and the Utility's long-term debt:

	December 31,	
	2006	**2005**
(in millions)		
PG&E Corporation		
Convertible subordinated notes, 9.50%, due 2010	$ 280	$ 280
Less: current portion	(280)	-
	-	280
Utility		
Senior notes/first mortgage bonds [(1)]:		
3.60% to 6.05% bonds, due 2009-2034	5,100	5,100

Unamortized discount, net of premium	(16)	(17)
Total senior notes/first mortgage bonds	5,084	5,083
Pollution control bond loan agreements, variable rates [2] , due 2026 [3]	614	614
Pollution control bond loan agreement, 5.35%, due 2016	200	200
Pollution control bond loan agreements, 3.50%, due 2023 [4]	345	345

Pollution control bond loan agreements, variable rates [5], due 2016-2026	454	454
Other	1	2
Less: current portion	(1)	(2)
Long-term debt, net of current portion	6,697	6,696
Total consolidated long-term debt, net of current portion	$ 6,697	$ 6,976

[1] When originally issued, these debt instruments were denominated as first mortgage bonds and were secured by a lien, subject to permitted exceptions, on substantially all of the Utility's real property and certain tangible personal property related to its facilities. The indenture under which the first mortgage bonds were issued provided for release of the lien in certain circumstances subject to certain conditions. The release occurred in April 2005 and the remaining bonds were redesignated as senior notes.

[2] At December 31, 2006, interest rates on these loans ranged from 3.80% to 3.92%.

[3] These bonds are supported by $620 million of letters of credit which expire on April 22, 2010. Although the stated maturity date is 2026, the bonds will remain outstanding only if the Utility extends or replaces the letters of credit.

[4] These bonds are subject to a mandatory tender for purchase on June 1, 2007 and the interest rates for these bonds are set until that date.

[5] At December 31, 2006, interest rates on these loans ranged from 3.25% to 3.70%.

PG&E Corporation

Convertible Subordinated Notes

At December 31, 2006, PG&E Corporation had outstanding $280 million of 9.5% Convertible Subordinated Notes that are scheduled to mature on June 30, 2010, or Convertible Subordinated Notes. 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 shares of common stock outstanding. In addition, holders of the Convertible Subordinated Notes are entitled to receive "pass-through dividends" determined by multiplying the cash dividend paid by PG&E Corporation per share of common stock by a number equal to the principal amount of the Convertible Subordinated Notes divided by the conversion price. In connection with common stock dividends paid to holders of PG&E Corporation common stock in 2006, PG&E Corporation paid approximately $24 million of "pass through dividends" to the holders of Convertible Subordinated Notes. The holders have a one-time right to require PG&E Corporation to repurchase the Convertible Subordinated Notes on June 30, 2007, at a purchase price equal to the principal amount plus accrued and unpaid interest (including liquidated damages and unpaid "pass-through dividends," if any). Accordingly, PG&E Corporation has classified the Convertible Subordinated Notes in Current Liabilities - Long-term debt, in the accompanying Consolidated Balance Sheet as of December 31, 2006.

In accordance with SFAS No. 133, the dividend participation rights component of the Convertible Subordinated Notes is considered to be an embedded derivative instrument and, therefore, must be bifurcated from the Convertible Subordinated Notes and recorded at fair value in PG&E Corporation's Consolidated Financial Statements. Changes in the fair value are recognized in PG&E Corporation's Consolidated Statements of Income as a non-operating expense or income (included in Other income (expense), net). At December 31, 2006 and 2005, the total estimated fair value of the dividend participation rights component, on a pre-tax basis, was approximately $79 million and $92 million, respectively, of which $23 million and $22 million, respectively, was classified as a current liability (in Current liabilities-Other) and $56 million and $70 million, respectively, was classified as a noncurrent liability (in Noncurrent liabilities-Other).

Utility

Senior Notes

The Senior Notes are unsecured general obligation ranking equal with the Utility's other senior unsecured debt. Under the indenture of 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 provided that the Senior Notes will be equally and ratably secured with the new secured debt.

At December 31, 2006, there were $5.1 billion of Senior Notes outstanding.

Pollution Control Bonds

The California Pollution Control Financing Authority and the California Infrastructure and Economic Development Bank, or CIEDB, issued various series of tax-exempt pollution control bonds for the benefit of the Utility. At December 31, 2006, pollution control bonds in the aggregate principal amount of $1.6 billion were outstanding. Under the pollution control bond loan agreements, the Utility is obligated to pay on the due dates an amount equal to the principal, premium, if any, and interest on these bonds to the trustees for these bonds.

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

In order to enhance the credit ratings of these pollution control bonds, the Utility has obtained credit support from banks and insurance companies such that, in the event that the Utility does not pay debt servicing costs, the banks or insurance companies will pay the debt servicing costs. The following table summarizes these credit supports:

(in millions)

Utility Facility [1]	**Series**	**Termination Date**	**At December 31, 2006 Commitment**
Pollution control bond bank reimbursement agreements	96 C, E, F, 97 B	April 2010	$ 620
Pollution control bond - bond insurance reimbursement agreements	96A	December 2016 [2]	200
Pollution control bond - bond insurance reimbursement agreements	2004 A - D	December 2023 [2]	345
Pollution control bond - bond insurance reimbursement agreements	2005 A - G	2016 - 2026 [2]	454
Total credit support			$ 1,619

(1) Off-balance sheet commitments.
(2) Principal and debt service insured by the bond insurance company.

On April 20, 2005, the Utility repaid $454 million under pollution control bond loan agreements that the Utility had entered into in April 2004. The repayment of these reimbursement agreements was made through $454 million of borrowings under the Utility's working capital facility (see further discussion of the working capital facility below). Subsequently, on May 24, 2005, the Utility entered into seven loan agreements with the CIEDB 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 where interest rates are set among investors who submit bids to buy, sell, or hold securities at desired rates. Four series of the bonds (Series A-D) have auctions every 35 days and three series (Series E-G) have auctions every seven days. Maturities on the bonds range from 2016 to 2026. The Utility repaid borrowings under the working capital facility using the proceeds from the tax-exempt PC Bonds Series A -G.

In April and November 2005, the Utility amended the four bank reimbursement agreements totaling $620 million, and relating to letters of credit issued to provide the credit support for the PC Bonds referred to above, to reduce pricing and generally conforming the covenants and events of default to those in the Utility’s working capital facility (described below), as well as extend their terms to April 22, 2010.

Repayment Schedule

At December 31, 2006, PG&E Corporation's and the Utility's combined aggregate principal repayment amounts of long-term debt are reflected in the table below:

(in millions, except interest rates)	**2007**	**2008**	**2009**	**2010**	**2011**	**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	-	-	3.60%	-	4.20%	5.55%	5.22%
Fixed rate obligations	$ -	$ -	$ 600	$ -	$ 500	$ 4,529	$ 5,629
Variable interest rate as of December 31, 2006	-	-	-	3.88%	-	3.59%	3.76%
Variable rate obligations	$ -	$ -	$ -	$ 614 [1]	$ -	$ 454	$ 1,068
Other	$ 1	$ -	$ -	$ -	$ -	$ -	$ 1
Less: current portion	(281)	-	-	-	-	-	(281)
Total consolidated long-term debt	$ -	$ -	$ 600	$ 614	$ 500	$ 4,983	$ 6,697

[1] The $614 million pollution control bonds, due in 2026, are backed by letters of credit which expire on April 22, 2010. The bonds will be subject to a mandatory redemption unless the letters of credit are extended or replaced. Accordingly, the bonds have been classified for repayment purposes in 2010.

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 December 31, 2006:

(in millions)

			At December 31, 2006				
Authorized Borrower	**Facility**	**Termination Date**	**Facility Limit**	**Letters of Credit Out-standing**	**Cash Borrowings**	**Commercial Paper Backup**	**Availability**
PG&E Corporation	Senior credit facility	December 2009	$ 200 [1]	$ -	$ -	$ -	$ 200
Utility	Accounts receivable financing	March 2007	650	-	300	-	350
Utility	Working capital facility	April 2010	1,350 [2]	144	-	460	746
Total credit facilities			$ 2,200	$ 144	$ 300	$ 460	$ 1,296

[1] Includes $50 million sublimit for letters of credit and $100 million sublimit for swingline loans, which are made available on a same-day basis and repayable in full within 30 days.

[2] Includes a $950 million sublimit for letters of credit and $100 million sublimit for swingline loans, which are made available on a same-day basis and repayable in full within 30 days.

PG&E Corporation

Senior Credit Facility

PG&E Corporation has a $200 million revolving senior unsecured credit facility, or senior credit facility, with a syndicate of lenders that, as amended, extends to December 10, 2009. Borrowings under the senior credit facility and letters of credit may be used for working capital and other corporate purposes. PG&E Corporation can, at any time, repay amounts outstanding in whole or in part. At PG&E Corporation's request and at the sole discretion of each lender, the senior credit facility may be extended for additional periods. PG&E Corporation has the right to increase, in one or more requests given no more than once a year, the aggregate facility by up to $100 million provided certain conditions are met. At December 31, 2006, PG&E Corporation had not undertaken 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 Standard & Poor's Ratings Service, or S&P, and Moody's Investors Service, or Moody's. Interest is payable quarterly in arrears,

or earlier for loans with shorter interest periods. In addition, a facility fee based on the aggregate facility and a utilization fee based on the average daily amount outstanding under the senior credit facility are payable quarterly in arrears by PG&E Corporation.

In addition, PG&E Corporation pays a fee for each letter of credit outstanding under the senior credit facility and a fronting fee to the issuer of a letter of credit. Interest, fronting fees, normal lender costs of issuing and negotiating letter of credit arrangements are payable quarterly in arrears.

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. In general, the covenants, representations and events of default mirror those in the Utility's working capital facility, discussed below. In addition, the senior credit facility also requires that PG&E Corporation maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% and that PG&E Corporation own, directly or indirectly, at least 80% of the common stock and at least 70% of the voting securities of the Utility.

Utility

Accounts Receivable Financing

On March 5, 2004, the Utility entered into certain agreements providing for the continuous sale of a portion of the Utility's accounts receivable to PG&E Accounts Receivable Company, LLC, or PG&E ARC, a limited liability company wholly owned by the Utility. In turn, PG&E ARC sells interests in its accounts receivable to commercial paper conduits or banks. PG&E ARC may obtain up to $650 million of financing under such agreements. The borrowings under this facility bear interest at commercial paper rates and a fixed margin based on the Utility's credit ratings. Interest on the facility is payable monthly. At December 31, 2006, the average interest rate on borrowings on the accounts receivable facility was 5.36%. The maximum amount available for borrowing under this facility changes based upon the amount of eligible receivables, concentration of eligible receivables and other factors. The accounts receivable facility will terminate on March 5, 2007. The Utility is seeking an increase to its bank credit facilities in light of the impending expiration of the accounts receivable facility. There were $300 million of borrowings outstanding under the accounts receivable facility at December 31, 2006 and $260 million of borrowings outstanding at December 31, 2005.

Although PG&E ARC is a wholly owned consolidated subsidiary of the Utility, PG&E ARC is legally separate from the Utility. The assets of PG&E ARC (including the accounts receivable) are not available to creditors of the Utility or PG&E Corporation, and the accounts receivable are not legally assets of the Utility or PG&E Corporation. For the purposes of financial reporting, the credit facility is accounted for as a secured financing.

The accounts receivable facility includes a covenant from the Utility requiring it to maintain, as of the end of each fiscal quarter ending after the effective date of the Utility's plan of reorganization, a debt to capitalization ratio of at most 65%.

Working Capital Facility

The Utility has a $1.35 billion credit facility, or the working capital facility. Loans under the working capital facility are used primarily to cover operating expenses and seasonal fluctuations in cash flows and were used for bridge financing in connection with the repayment of the pollution control bond loan agreements discussed above. Letters of credit under the working capital facility are used primarily to provide credit enhancements to counterparties for natural gas and energy 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 calendar 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 terminates or expires, by up to $850 million, in the aggregate for all such increases.

The working capital facility expires 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 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. The Utility is also required to pay a facility fee based on the total amount of working capital facility (regardless of the usage) and a utilization fee based on the average daily amount outstanding under the working capital facility. Interest is payable quarterly in arrears, or earlier for loans with shorter interest periods.

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.

At December 31, 2006, there were no loans outstanding and approximately $144 million of letters of credit outstanding under

the $1.35 billion working capital facility. Additionally, the working capital facility supports the $460 million of outstanding commercial paper discussed below.

Commercial Paper Program

On January 10, 2006, the Utility entered into various agreements to establish the terms and procedures for the issuance of up to $1 billion of unsecured commercial paper by the Utility for general corporate purposes. The commercial paper is not registered under the Securities Act of 1933 or applicable state securities laws and may not be offered or sold in the United States absent registration under the Securities Act of 1933 or applicable state exemption from registration requirements. The commercial paper may have maturities up to 365 days and ranks equally with the Utility's unsubordinated and unsecured indebtedness. At December 31, 2006, the Utility had $460 million, including amortization of a $2 million discount, of commercial paper outstanding at an average yield of approximately 5.44%. Commercial paper notes are sold at an interest rate dictated by the market at the time of issuance.

NOTE 5: RATE REDUCTION BONDS

In December 1997, PG&E Funding LLC, a limited liability corporation wholly owned by and consolidated by the Utility, issued $2.9 billion of RRBs. The proceeds of the RRBs were used by PG&E Funding LLC to purchase from the Utility the right, known as "transition property," to be paid a specified amount from a non-bypassable charge levied on residential and small commercial customers (Fixed Transition Amount, or FTA, charges). FTA charges are authorized by the CPUC under state legislation and will be paid by residential and small commercial customers until the RRBs are fully retired. Under the terms of a transition property servicing agreement, FTA charges are collected by the Utility and remitted to PG&E Funding LLC for the payment of the bond principal, interest and miscellaneous expenses associated with the bonds.

The total amount of RRB principal outstanding was $290 million at December 31, 2006 and $580 million at December 31, 2005. The scheduled quarterly principal payments on the RRBs for 2007 total $290 million at a 6.48% interest rate. The RRBs are scheduled to mature on December 26, 2007.

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

NOTE 6: ENERGY RECOVERY BONDS

In furtherance of the Chapter 11 Settlement Agreement, PG&E Energy Recovery Funding LLC, or PERF, a wholly owned consolidated subsidiary of the Utility, issued two separate series of ERBs in the aggregate amount of $2.7 billion in 2005 supported by a dedicated rate component, or DRC. 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 for payment of the bond principal, interest and miscellaneous expenses associated with the bonds.

The first series of ERBs issued on February 10, 2005 included five classes aggregating approximately $1.9 billion principal amount with scheduled maturities ranging from September 25, 2006 to December 25, 2012. Interest rates on the five classes range from 3.32% for the earliest maturing class, which matured on September 25, 2006, 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 second series of ERBs, issued on November 9, 2005, included three classes aggregating approximately $844 million principal amount, with scheduled maturities ranging from June 25, 2009 to December 25, 2012. Interest rates on the three classes range from 4.85% for the earliest maturing class to 5.12% for the latest maturing class. The proceeds of the second series of ERBs were paid by PERF to the Utility to pre-fund the Utility's tax liability that will be due as the Utility collects the DRC related to the first series of ERBs.

The total amount of ERB principal outstanding was $2.3 billion at December 31, 2006 and $2.6 billion at December 31, 2005. The scheduled repayments for ERBs are reflected in the table below:

(in millions)	**2007**	**2008**	**2009**	**2010**	**2011**	**Thereafter**	**Total**
Utility							
Average fixed interest rate	4.19%	4.19%	4.36%	4.49%	4.61%	4.64%	4.43%
Energy recovery bonds	$ 340	$ 354	$ 369	$ 386	$ 424	$ 403	$ 2,276

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

NOTE 7: DISCONTINUED OPERATIONS

NEGT, formerly known as PG&E National Energy Group, Inc., was incorporated on December 18, 1998, as a wholly owned subsidiary of PG&E Corporation. NEGT filed a voluntary petition for relief under Chapter 11 on July 8, 2003, and as a result, PG&E Corporation no longer consolidated NEGT and its subsidiaries in its Consolidated Financial Statements. Consolidation is generally required under GAAP for entities owning more than 50% of the outstanding voting stock of an investee, unless control is not held by the majority owner. Legal reorganization and bankruptcy can preclude consolidation in instances where control rests with an entity other than the majority owner. Because PG&E Corporation's representatives on the NEGT Board of Directors resigned on July 7, 2003, and were replaced with Board members who were not affiliated with PG&E Corporation, PG&E Corporation no longer retained significant influence over the ongoing operations of NEGT at the filing of the petition.

Accordingly, PG&E Corporation's net negative investment in NEGT of approximately $1.2 billion was reflected as a single amount, under the cost method, within the December 31, 2003 Consolidated Balance Sheet of PG&E Corporation. This negative investment represents the losses of NEGT recognized by PG&E Corporation in excess of its investment in and advances to NEGT.

PG&E Corporation’s equity ownership in NEGT was cancelled on October 29, 2004, the date when NEGT's plan of reorganization became effective. At that date, PG&E Corporation reversed its negative investment in NEGT and also reversed net deferred income tax assets of approximately $428 million and a charge of approximately $120 million ($77 million, after tax) in accumulated other comprehensive loss, related to NEGT. The resulting net gain has been offset by the $30 million payment made by PG&E Corporation to NEGT pursuant to the parties' settlement of certain tax-related litigation and other adjustments to NEGT-related liabilities. A summary of the effect on the year ended December 31, 2004 earnings from discontinued operations is as follows:

(in millions)		
Negative investment in NEGT	$	1,208
Accumulated other comprehensive loss		(120)
Cash paid pursuant to settlement of tax related litigation		(30)
Tax effect		(374)
Gain on disposal of NEGT, net of tax	$	684

During the third quarter of 2005, PG&E Corporation received additional information from NEGT regarding income to be included in PG&E Corporation's 2004 federal income tax return. This information was incorporated in the 2004 tax return, which was filed with the Internal Revenue Service, or IRS, in September 2005. As a result, the 2004 federal income tax liability was reduced by approximately $19 million. In addition, NEGT provided additional information with respect to amounts previously included in PG&E Corporation's 2003 federal income tax return. This change resulted in PG&E Corporation's 2003 federal income tax liability increasing by approximately $6 million. These two adjustments, netting to $13 million, were recognized in income from discontinued operations in 2005.

At December 31, 2005, PG&E Corporation’s Consolidated Balance Sheet included approximately $89 million of current income taxes payable and approximately $27 million of other net liabilities related to NEGT. At December 31, 2006, PG&E Corporation’s Consolidated Balance Sheet included approximately $89 million of current income taxes payable and approximately $26 million of other net liabilities related to NEGT. Until PG&E Corporation reaches final settlement of these obligations, it will continue to disclose fluctuations in these estimated liabilities in discontinued operations. PG&E Corporation ceased including NEGT and its subsidiaries in its consolidated income tax returns beginning October 29, 2004.

NOTE 8: COMMON STOCK

PG&E Corporation

PG&E Corporation has authorized 800 million shares of no-par common stock of which 374,181,059 shares were issued and outstanding at December 31, 2006 and 368,268,502 were issued and outstanding at December 31, 2005. A wholly owned subsidiary of PG&E Corporation, Elm Power Corporation, holds 24,665,500 of the outstanding shares.

Of the 374,181,059 shares issued and outstanding at December 31, 2006, 1,377,538 shares have been granted as restricted stock as share-based compensation awarded under the PG&E Corporation Long-Term Incentive Plan, or 2006 LTIP (see Note 14 for further discussion).

In 2002, PG&E Corporation issued warrants to purchase 5,066,931 shares of its common stock at an exercise price of $0.01 per share. During 2006, 51,890 shares of PG&E Corporation common stock were issued upon exercise of the warrants. As of December 31, 2006, all warrants issued had been exercised.

Stock Repurchases

During 2004, 1,863,600 shares of PG&E Corporation common stock were repurchased for an aggregate purchase price of approximately $60 million. Of this amount, 850,000 shares were purchased at a cost of approximately $28 million and are held by Elm Power Corporation.

On December 15, 2004, PG&E Corporation entered into an accelerated share repurchase agreement, or ASR, with Goldman Sachs & Co., Inc., or GS&Co., under which PG&E Corporation repurchased 9,769,600 shares of its outstanding common stock for an aggregate purchase price of approximately $332 million, including a $14 million price adjustment paid on February 22, 2005. This adjustment was based on the daily volume weighted average market price, or VWAP, of PG&E Corporation common stock over the term of the arrangement.

In 2005, PG&E Corporation repurchased a total of 61,139,700 shares of its outstanding common stock through two ASRs with GS&Co. for an aggregate purchase price of $2.2 billion, including price adjustments based on the VWAP and other amounts. In 2006, PG&E Corporation paid GS&Co. $114 million in additional payments (net of amounts payable by GS&Co. to PG&E Corporation) to satisfy obligations under the last of these ASRs entered into in November 2005. PG&E Corporation's payments reduced common shareholders' equity. PG&E Corporation has no remaining obligation under the November 2005 ASR.

To reflect the potential dilution that existed while the obligations related to the ASRs were outstanding, PG&E Corporation treated approximately 1 million additional shares of PG&E Corporation common stock as outstanding for purposes of calculating diluted EPS for 2006 (see Note 10 below).

Utility

The Utility is authorized to issue 800 million shares of its $5 par value common stock, of which 279,624,823 shares were issued and outstanding as of December 31, 2006 and 2005. PG&E Holdings, LLC, a wholly owned subsidiary of the Utility, holds 19,481,213 of the outstanding shares. PG&E Corporation and PG&E Holdings, LLC hold all of the Utility's outstanding common stock.

The Utility may pay common stock dividends and repurchase its common stock, provided cumulative preferred dividends on its preferred stock are paid. As further discussed in Note 9, on the effective date of the Utility's plan of reorganization, the Utility paid cumulative preferred dividends and preferred sinking fund payments related to 2004, 2003 and 2002.

Dividends

PG&E Corporation and the Utility did not declare or pay a dividend during the Utility's Chapter 11 proceeding as the Utility was prohibited from paying any common or preferred stock dividends without Bankruptcy Court approval and certain covenants in the indenture related to senior secured notes of PG&E Corporation during that period restricted the circumstances in which such a dividend could be declared or paid. With the Utility's emergence from Chapter 11 on April 12, 2004, the Utility resumed the payment of preferred stock dividends. The Utility reinstated the payment of a regular quarterly common stock dividend to PG&E Corporation in January 2005, upon the achievement of the 52% equity ratio targeted in the Chapter 11 Settlement Agreement.

During 2005, the Utility paid cash dividends of $476 million on the Utility's common stock. Approximately $445 million in dividends was paid to PG&E Corporation and the remainder was paid to PG&E Holdings, LLC, a wholly owned subsidiary of the Utility. On April 15, July 15 and October 15, 2005, PG&E Corporation paid a quarterly common stock dividend of $0.30 per share, totaling approximately $356 million, including approximately $22 million of common stock dividends paid to Elm Corporation, a wholly owned subsidiary of PG&E Corporation.

During 2006, the Utility paid cash dividends of $494 million on the Utility's common stock. Approximately $460 million in common stock dividends were paid to PG&E Corporation and the remaining amount was paid to PG&E Holdings LLC. PG&E Holdings, LLC held approximately 7% of the Utility's common stock as of February 20, 2007.

On January 16, April 15, July 15, and October 15, 2006, PG&E Corporation paid common stock dividends of $0.33 per share, totaling approximately $489 million, including approximately $33 million of common stock dividends paid to Elm Power Corporation, a wholly owned subsidiary of PG&E Corporation that held approximately 7% of PG&E Corporation's common stock as of February 20, 2007.

On December 20, 2006, the Board of Directors of PG&E Corporation declared a dividend of $0.33 per share, totaling approximately $123 million that was payable to shareholders of record on December 29, 2006 on January 15, 2007. PG&E Corporation and the Utility record common stock dividends declared to Reinvested Earnings.

NOTE 9: PREFERRED STOCK

PG&E Corporation has authorized 85 million shares of preferred stock, which may be issued as redeemable or nonredeemable preferred stock. No preferred stock of PG&E Corporation has been issued.

Utility

The Utility has authorized 75 million shares of $25 par value preferred stock and 10 million shares of $100 par value preferred stock. The Utility specifies that 5,784,825 shares of the $25 par value preferred stock authorized are designated as nonredeemable preferred stock without mandatory redemption provisions. The remainder of the 75 million shares of $25 par value preferred stock and the 10 million shares of $100 par value preferred stock may be issued as redeemable or nonredeemable preferred stock.

At December 31, 2006 and 2005, the Utility had issued and outstanding 5,784,825 shares of nonredeemable $25 par value preferred stock without mandatory redemption provisions. Holders of the Utility's 5.0%, 5.5% and 6.0% series of nonredeemable $25 par value preferred stock have rights to annual dividends ranging from $1.25 to $1.50 per share.

At December 31, 2006 and 2005, the Utility had issued and outstanding 4,534,958 shares of redeemable $25 par value preferred stock without mandatory redemption provisions. The Utility's redeemable $25 par value preferred stock is subject to redemption at the Utility's option, in whole or in part, if the Utility pays the specified redemption price plus accumulated and unpaid dividends through the redemption date. At December 31, 2006, annual dividends ranged from $1.09 to $1.25 per share and redemption prices ranged from $25.75 to $27.25 per share.

The last of the Utility’s redeemable $25 par value preferred stock with mandatory redemption provisions was redeemed on May 31, 2005. Currently the Utility does not have any shares of the $100 par value preferred stock with or without mandatory redemption provisions outstanding.

Dividends on all Utility preferred stock are cumulative. All shares of preferred stock have voting rights and an equal preference in dividend and liquidation rights. Because it could not pay dividends during its Chapter 11 proceeding, the Utility paid approximately $82 million in dividends on Utility preferred stock and preferred sinking fund payments on the effective date of the Utility’s plan of reorganization. Throughout the remainder of 2004, the Utility paid dividends of approximately $19 million. During the year ended December 31, 2005, the Utility paid approximately $16 million of dividends on preferred stock without mandatory redemption provisions and approximately $5 million of dividends on preferred stock with mandatory redemption provisions. During the year ended December 31, 2006, the Utility paid approximately $14 million of dividends on preferred stock without mandatory redemption provisions. On February 21, 2007 the Board of Directors of the Utility declared a cash dividend on various series of its preferred stock, payable on May 5, 2007, to shareholders of record on April 30, 2007. Upon liquidation or dissolution of the Utility, holders of preferred stock would be entitled to the par value of such shares plus all accumulated and unpaid dividends, as specified for the class and series.

On June 15, 2005, the Utility's Board of Directors authorized the redemption of all of the outstanding shares of the Utility's 7.04% Redeemable First Preferred Stock totaling approximately $36 million aggregate par value plus approximately $1 million related to a $0.70 per share redemption premium. This issue was fully redeemed on August 31, 2005. In addition to the $25 per share redemption price, holders of the 7.04% Redeemable First Preferred Stock received an amount equal to all accumulated and unpaid dividends through August 31, 2005 on such shares totaling approximately $211,000.

NOTE 10: EARNINGS PER SHARE

EPS is calculated, utilizing the "two-class" method, by dividing the sum of distributed earnings to common shareholders and undistributed earnings allocated to common shareholders by the weighted average number of common shares outstanding during the period. In applying the "two-class" method, undistributed earnings are allocated to both common shares and participating securities. Holders of PG&E Corporation's Convertible Subordinated Notes are entitled to receive (non-cumulative) dividend payments prior to exercising the conversion option. As a result of this feature, the Convertible Subordinated Notes meet the criteria of a participating security. 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 net income per share:

(in millions, except per share amounts)	Year ended December 31, 2006	2005	2004
Net Income	$ 991	$ 917	$ 4,504
Less: distributed earnings to common shareholders	460	449	-
Undistributed earnings	531	468	4,504
Less: undistributed earnings from discontinued operations	-	13	684
Undistributed earnings from continuing operations	$ 531	$ 455	$ 3,820
Common shareholders earnings			
Basic			
Distributed earnings to common shareholders	$ 460	$ 449	$ -
Undistributed earnings allocated to common shareholders - continuing operations	503	433	3,646
Undistributed earnings allocated to common shareholders - discontinued operations	-	12	653
Total common shareholders earnings, basic	$ 963	$ 894	$ 4,299
Diluted			
Distributed earnings to common shareholders	$ 460	$ 449	$ -
Undistributed earnings allocated to common shareholders - continuing operations	504	433	3,650
Undistributed earnings allocated to common shareholders - discontinued operations	-	12	653
Total common shareholders earnings, diluted	$ 964	$ 894	$ 4,303
Weighted average common shares outstanding, basic	346	372	398
9.50% Convertible Subordinated Notes	19	19	19
Weighted average common shares outstanding and participating securities, basic	365	391	417
Weighted average common shares outstanding, basic	346	372	398
Employee share-based compensation and accelerated share repurchases [1]	3	6	7
PG&E Corporation warrants	-	-	2
Weighted average common shares outstanding, diluted	349	378	407
9.50% Convertible Subordinated Notes	19	19	19
Weighted average common shares outstanding and participating securities, diluted	368	397	426
Net earnings per common share, basic			
Distributed earnings, basic [2]	$ 1.33	$ 1.21	$ -
Undistributed earnings - continuing operations, basic	1.45	1.16	9.16
Undistributed earnings - discontinued operations, basic	-	0.03	1.64
Total	$ 2.78	$ 2.40	$ 10.80
Net earnings per common share, diluted			
Distributed earnings, diluted	$ 1.32	$ 1.19	$ -
Undistributed earnings - continuing operations, diluted	1.44	1.15	8.97
Undistributed earnings - discontinued operations, diluted	-	0.03	1.60
Total	$ 2.76	$ 2.37	$ 10.57

[1] Includes approximately 1 million, 2 million and 222,000 shares of PG&E Corporation common stock treated as outstanding in connection with accelerated share repurchases for the year ended December 31, 2006, December 31, 2005 and December 31, 2004, respectively. The remaining shares of approximately 2 million at December 31, 2006, 4 million at December 31, 2005 and 6.8 million at December 31, 2004, relate to share-based compensation and are deemed to be outstanding under SFAS No. 128 for the purpose of calculating EPS. See section of

Note 2 entitled “Earnings Per Share.”

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

PG&E Corporation stock options to purchase 28,500 and 7,046,710 shares were excluded from the computation of diluted EPS for 2005 and 2004, respectively, because the exercise prices of these options were greater than the average market price of PG&E Corporation common stock during these years. All PG&E Corporation stock options were included in the computation of diluted EPS for 2006 because the exercise price of these stock options was lower than the average market price of PG&E Corporation common stock during the year.

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

NOTE 11: INCOME TAXES

The significant components of income tax (benefit) expense for continuing operations were:

	PG&E Corporation			Utility		
	Year Ended December 31,					
(in millions)	**2006**	**2005**	**2004**	**2006**	**2005**	**2004**
Current:						
Federal	$ 743	$ 1,027	$ 121	$ 771	$ 1,048	$ 73
State	201	189	91	210	196	85
Deferred:						
Federal	(286)	(574)	1,877	(276)	(572)	2,000
State	(98)	(89)	384	(97)	(89)	410
Tax credits, net	(6)	(9)	(7)	(6)	(9)	(7)
Income tax expense	$ 554	$ 544	$ 2,466	$ 602	$ 574	$ 2,561

The following describes net deferred income tax liabilities:

	PG&E Corporation		Utility	
	Year ended December 31,			
(in millions)	**2006**	**2005**	**2006**	**2005**
Deferred income tax assets:				
Customer advances for construction	$ 806	$ 607	$ 806	$ 607
Reserve for damages	165	276	165	276
Environmental reserve	177	188	177	188
Compensation	131	90	95	66
Other	206	382	166	300
Total deferred income tax assets	$ 1,485	$ 1,543	$ 1,409	$ 1,437
Deferred income tax liabilities:				
Regulatory balancing accounts	$ 1,305	$ 1,719	$ 1,305	$ 1,719
Property related basis differences	2,778	2,694	2,778	2,694
Income tax regulatory asset	243	218	243	218
Unamortized loss on reacquired debt	120	128	120	128
Other	27	57	53	57
Total deferred income tax liabilities	$ 4,473	$ 4,816	$ 4,499	$ 4,816
Total net deferred income tax liabilities	$ 2,988	$ 3,273	$ 3,090	$ 3,379
Classification of net deferred income tax liabilities:				
Included in current liabilities	$ 148	$ 181	$ 118	$ 161
Included in noncurrent liabilities	2,840	3,092	2,972	3,218

Total net deferred income tax liabilities	$ 2,988	$ 3,273	$ 3,090	$ 3,379

The differences between income taxes and amounts calculated by applying the federal legal rate to income before income tax expense for continuing operations were:

	PG&E Corporation			Utility		
	Year Ended December 31,					
	2006	2005	2004	2006	2005	2004
Federal statutory income tax rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) in income tax rate resulting from:						
State income tax (net of federal benefit)	4.3	4.5	4.6	4.6	4.7	4.7
Effect of regulatory treatment of depreciation differences	0.6	0.9	(0.5)	0.6	0.9	(0.4)
Tax credits, net	(0.6)	(1.0)	(0.2)	(0.6)	(1.0)	(0.2)
Other, net	(3.4)	(1.8)	0.3	(1.6)	(1.6)	0.2
Effective tax rate	35.9%	37.6%	39.2%	38.0%	38.0%	39.3%

The IRS has completed its audit of PG&E Corporation's 1997 and 1998 consolidated federal income tax returns and has assessed additional federal income taxes of approximately $87 million (including interest). PG&E Corporation filed protests contesting certain adjustments made by the IRS in that audit. In April 2006, PG&E Corporation and the IRS Appeals Office tentatively resolved the contested adjustments. However, another claim for refund, which PG&E Corporation filed with the IRS in December 2000, was transferred to the IRS Appeals Office in late 2006, and incorporated as part of the IRS's audit of PG&E Corporation's 1997 and 1998 consolidated federal income tax returns. This transfer will delay the final resolution of this audit. PG&E Corporation has not accrued a tax benefit regarding this claim.

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

The IRS is also currently auditing PG&E Corporation's 2003 and 2004 consolidated federal income tax returns.

As of December 31, 2006, PG&E Corporation had accrued approximately $138 million for potential non-Utility tax obligations and interest related to outstanding audits, including the $89 million related to the proposed disallowance of deduction for abandoned or worthless assets owned by NEGT discussed above, and $49 million to cover potential tax obligations related to non-NEGT issues. The Utility had accrued approximately $52 million as of December 31, 2006, to cover potential tax obligations for outstanding audits. There have been no changes in the reserve balance since December 31, 2005.

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

PG&E Corporation recorded tax benefits of $19 million from capital losses carried forward and used in its 2005 federal and California income tax returns. PG&E Corporation has $229 million of remaining capital loss carry forwards from the disposition of its NEGT ownership interest in 2004, which, if not used by December 2009, will expire.

NOTE 12: DERIVATIVES AND HEDGING ACTIVITIES

The Utility enters into contracts to procure electricity, natural gas, nuclear fuel and firm electricity transmission rights. Except for contracts that meet the definition of normal purchases and sales, all derivative instruments including instruments designated as cash flow hedges of natural gas in the natural gas portfolios, are recorded at fair value and presented as price risk management assets and liabilities on the balance sheet. On PG&E Corporation's and the Utility's Consolidated Balance Sheets, price risk management activities appear as summarized below:

	December 31, 2006	December 31, 2005

(in millions)		
Current Assets - Prepaid expenses and other	$ 16	$ 140

Other Noncurrent Assets - Other	$	37	$	212
Current Liabilities - Other	$	192	$	2
Noncurrent Liabilities - Other	$	50	$	-

Since these contracts are used within the regulatory framework, regulatory accounts are recorded to offset the costs and proceeds of these derivatives recognized in earnings and subsequently recovered in regulated rates charged to customers.

For cash flow hedges, the Utility recorded $8 million as Noncurrent Liabilities-Regulatory liabilities, $3 million as current regulatory liabilities (included in Current Liabilities-Other), and $25 million as current regulatory assets (included in Current Assets-Prepaid expenses and other) at December 31, 2006, compared to $59 million as Noncurrent Liabilities-Regulatory liabilities, $2 million as current regulatory liabilities (included in Current Liabilities-Other), and less than $1 million as Other Noncurrent Assets-Regulatory assets at December 31, 2005.

NOTE 13: NUCLEAR DECOMMISSIONING

The Utility's nuclear power facilities consist of two units at Diablo Canyon and the retired facility at Humboldt Bay Unit 3, or Humboldt Bay Unit 3. Nuclear decommissioning requires the safe removal of nuclear facilities from service and the reduction of residual radioactivity to a level that permits termination of the Nuclear Regulatory Commission, or NRC, license and release of the property for unrestricted use. For ratemaking purposes, the eventual decommissioning of Diablo Canyon Unit 1 is scheduled to begin in 2024 and to be completed in 2044. Decommissioning of Diablo Canyon Unit 2 is scheduled to begin in 2025 and to be completed in 2041, and decommissioning of Humboldt Bay Unit 3 is scheduled to begin in 2009 and to be completed in 2015.

As presented in the Utility’s Nuclear Decommissioning Costs Triennial Proceeding, the estimated nuclear decommissioning cost for the Diablo Canyon Units 1 and 2 and Humboldt Bay Unit 3 is approximately $2.11 billion in 2006 dollars (or approximately $5.42 billion in future dollars). These estimates are based on the 2006 decommissioning cost studies, prepared in accordance with CPUC requirements. The Utility's revenue requirements for nuclear decommissioning costs are recovered from customers through a non-bypassable charge that will continue until those costs are fully recovered. The decommissioning cost estimates are based on the plant location and cost characteristics for the Utility's nuclear power plants. Actual decommissioning costs may vary from these estimates as a result of changes in assumptions such as decommissioning dates, regulatory requirements, technology, and costs of labor, materials and equipment.

The estimated nuclear decommissioning cost described above is used for regulatory purposes. Decommissioning costs recovered in rates are placed in nuclear decommissioning trusts. However, under GAAP requirements, the decommissioning cost estimate is calculated using a different method. In accordance with SFAS No. 143, the Utility adjusts its nuclear decommissioning obligation to reflect the fair value of decommissioning its nuclear power facilities. The Utility records the Utility's total nuclear decommissioning obligation as an asset retirement obligation on the Utility's Consolidated Balance Sheet. Decommissioning costs are recorded as a component of depreciation expense, with a corresponding credit to the asset retirement costs regulatory liability. The total nuclear decommissioning obligation accrued in accordance with GAAP was approximately $1.2 billion at December 31, 2006 and $1.3 billion at December 31, 2005. The primary difference between the Utility's estimated nuclear decommissioning obligation as recorded in accordance with GAAP and the estimate prepared in accordance with the CPUC requirements is that GAAP incorporates various potential settlement dates for the obligation and includes an estimated amount for third-party labor costs into the fair value calculation.

The Utility has three decommissioning trusts for its Diablo Canyon and Humboldt Bay Unit 3 nuclear facilities. The Utility has elected that two of these trusts be treated under the Internal Revenue Code as qualified trusts. If certain conditions are met, the Utility is allowed a deduction for the payments made to the qualified trusts. The qualified trusts are subject to a lower tax rate on income and capital gains, thereby increasing the trusts' after-tax returns. Among other requirements, to maintain the qualified trust status the IRS must approve the amount to be contributed to the qualified trusts for any taxable year. The remaining non-qualified trust is exclusively for decommissioning Humboldt Bay Unit 3. The Utility cannot deduct amounts contributed to the non-qualified trust until such decommissioning costs are actually incurred.

The funds in the decommissioning trusts, along with accumulated earnings, will be used exclusively for decommissioning and dismantling the Utility's nuclear facilities. The trusts maintain substantially all of their investments in debt and equity securities. The CPUC has authorized the qualified trust to invest a maximum of 50% of its funds in publicly-traded equity securities, of which up to 20% may be invested in publicly-traded non-US equity securities. For the non-qualified trust, no more than 60% may be invested in publicly-traded equities, of which up to 20% may be invested in publicly-traded non-US equity securities. The allocation of the trust funds is monitored monthly. To the extent that market movements cause the asset allocation to move outside these ranges, the investments are rebalanced toward the target allocation.

The Utility estimates after-tax annual earnings, including realized gains and losses, in the qualified trusts to be 5.9% and in the non-qualified trusts to be 4.8%. Trust earnings are included in the nuclear decommissioning trust assets and corresponding SFAS No. 143 regulatory liability. There is no impact on the Utility's earnings. Annual returns decrease in later years as higher portions of the trusts are dedicated to fixed income investments leading up to and during the entire course of decommissioning activities.

All earnings on the assets held in the trusts, net of authorized disbursements from the trusts and investment management and administrative fees, are reinvested. Amounts may not be released from the decommissioning trusts until authorized by the CPUC. At December 31, 2006, the Utility had accumulated nuclear decommissioning trust funds with an estimated fair value of approximately $1.9 billion, based on quoted market prices and net of deferred taxes on unrealized gains.

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

The Utility records unrealized gains and losses on investments held in the trusts in other comprehensive income in accordance with SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities." Realized gains and losses are recognized as additions or reductions to trust asset balances. The Utility, however, accounts for its nuclear decommissioning obligations in accordance with SFAS No. 71; therefore, both realized and unrealized gains and losses are ultimately recorded as regulatory assets or liabilities.

In 2006, total unrealized losses on the investments held in the trusts were $2 million. FASB Staff Position Nos. 115-1 and 124-1,"The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments" state that an investment is impaired if the fair value of the investment is less than its cost and if the impairment is concluded to be other-than-temporary, an impairment loss is recognized. Since the day-to-day investing activities of the trusts are managed by external investment managers, the Utility is unable to conclude that the $2 million impairment is not other-than-temporary. As a result, an impairment loss was recognized and the Utility recorded a $2 million reduction to the nuclear decommissioning trusts assets and regulatory liability.

The following table provides a summary of the fair value, based on quoted market prices, of the investments held in the Utility's nuclear decommissioning trusts:

(in millions)	Maturity Date	Total Unrealized Gains	Total Unrealized Losses	Estimated Fair Value
Year ended December 31, 2006				
U.S. government and agency issues	2007-2036	$ 34	$ (1)	$ 814
Municipal bonds and other	2007-2049	7	(1)	258
Equity securities		644	-	991
Total		$ 685	$ (2)	$ 2,063
Year ended December 31, 2005				
U.S. government and agency issues	2006-2035	$ 42	$ (2)	$ 763
Municipal bonds and other	2006-2036	10	(1)	192
Equity securities		534	-	871
Total		$ 586	$ (3)	$ 1,826

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

	Year Ended December 31,		
(in millions)	2006	2005	2004
Proceeds received from sales of securities	$ 1,087	$ 2,918	$ 1,821
Gross realized gains on sales of securities held as available-for-sale	55	56	28

Gross realized losses on sales of securities held as available-for-sale	(29)	(14)	(22)

Spent Nuclear Fuel Storage Proceedings

Under the Nuclear Waste Policy Act of 1982, the Department of Energy, or the DOE, is responsible for the transportation and

permanent storage and disposal of spent nuclear fuel and high-level radioactive waste. The Utility has contracted with the DOE to provide for the disposal of these materials from Diablo Canyon. Under the contract, if the DOE completes a storage facility by 2010, the earliest that Diablo Canyon's spent fuel would be accepted for storage or disposal is thought to be 2018. Under current operating procedures, the Utility believes that the existing spent fuel pools (which include newly constructed temporary storage racks) have sufficient capacity to enable the Utility to operate Diablo Canyon until approximately 2010 for Unit 1 and 2011 for Unit 2. After receiving a permit from the NRC in March 2004, the Utility began building an on-site dry cask storage facility to store spent fuel through at least 2024. The Utility estimates it could complete the dry cask storage project in 2008. The NRC's March 2004 decision, however, was appealed by various parties, and the U.S. Court of Appeals for the Ninth Circuit issued a decision in 2006 that requires the NRC to consider the environmental consequences of a potential terrorist attack at Diablo Canyon as part of the NRC's supplemental assessment of the dry cask storage permit. The Utility may incur significant additional expenditures if the NRC decides that the Utility must change the design and construction of the dry cask storage facility. If the Utility is unable to complete the dry cask storage facility, or if construction is delayed beyond 2010, and if the Utility is otherwise unable to increase its on-site storage capacity, it is possible that the operation of Diablo Canyon may have to be curtailed or halted as early as 2010 with respect to Unit 1 and 2011 with respect to Unit 2 and until such time as additional spent fuel can be safely stored.

As a result of the DOE's failure to develop a permanent storage facility, the Utility has been required to incur substantial costs for planning and developing on-site storage options for spent nuclear fuel as described above at Diablo Canyon as well as at Humboldt Bay Unit 3. The Utility is seeking to recover these costs from the DOE on the basis that the DOE has breached its contractual obligation to move used nuclear fuel from Diablo Canyon and Humboldt Bay Unit 3 to a national repository beginning in 1998. Any amounts recovered from the DOE will be credited to customers. In October 2006, the U.S. Court of Federal Claims issued a decision awarding approximately $42.8 million of the $92 million incurred by the Utility through 2004. The Utility will seek recovery of costs incurred after 2004 in future lawsuits against the DOE. In January 2007, the Utility filed a notice of appeal of the U.S. Court of Federal Claims' decision in the U.S. Court of Appeals for the Federal Circuit seeking to increase the amount of the award and challenging the court's finding the Utility would have had to incur some of the costs for the onsite storage facilities even if the DOE had complied with the contract. If the court's decision is not overturned or modified on appeal, it is likely that the Utility will be unable to recover all of its future costs for onsite storage facilities from the DOE. However, reasonably incurred costs related to the onsite storage facilities are, in the case of Diablo Canyon, recoverable through rates and, in the case of Humboldt Bay Unit 3, recoverable through its decommissioning trust fund.

PG&E Corporation and the Utility are unable to predict the outcome of this appeal or the amount of any additional awards the Utility may receive.

NOTE 14: EMPLOYEE COMPENSATION PLANS

PG&E Corporation and its subsidiaries provide non-contributory defined benefit pension plans for certain employees and retirees, referred to collectively as pension benefits. PG&E Corporation and the Utility have elected that certain of the trusts underlying these plans be treated under the Internal Revenue Code as qualified trusts. If certain conditions are met, PG&E Corporation and the Utility can deduct payments made to the qualified trusts, subject to certain Internal Revenue Code limitations. PG&E Corporation and its subsidiaries also provide contributory defined benefit medical plans for certain retired employees and their eligible dependents, and non-contributory defined benefit life insurance plans for certain retired employees (referred to collectively as other benefits). The following schedules aggregate all PG&E Corporation's and the Utility's plans and are presented based on the sponsor of each plan. PG&E Corporation and its subsidiaries use a December 31 measurement date for all of their plans.

On December 31, 2006, PG&E Corporation and the Utility adopted SFAS No. 158. SFAS No. 158 requires the funded status of an entity's plans to be recognized on the balance sheet, eliminates the additional minimum liability, and enhances related disclosure requirements. The funded status of a plan, as measured under SFAS No. 158, is the difference between the fair value of plan assets and the projected benefit obligation for a pension plan and the accumulated postretirement benefit obligation for other postretirement benefit plans. SFAS No. 158 does not change the method of recording expense on the statement of income; therefore, the effects of adopting SFAS No. 158 did not have an impact on earnings or on cash flows.

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. For 2006, only the portion of the pension contribution allocated to the gas transmission and storage business is not recoverable in rates. For 2006, the reduction in net income as a result of the Utility not being able to recover this portion in rates was approximately $5 million, net of tax. A regulatory adjustment is also recorded for the amounts that would otherwise be charged to accumulated other comprehensive income under SFAS No. 158 for the pension benefits. Since 1993, the CPUC has authorized the Utility to recover the costs associated with its other benefits based on the lesser of the SFAS No. 106 expense or the annual tax deductible contributions to the appropriate trusts. This recovery mechanism does not allow the Utility to record a regulatory adjustment for the SFAS No. 158 charge to accumulated other comprehensive income related to other benefits.

Benefit Obligations

The following tables reconcile changes in aggregate projected benefit obligations for pension benefits and changes in the benefit obligation of other benefits during 2006 and 2005:

Pension Benefits

	PG&E Corporation		Utility	
	2006	2005	2006	2005
(in millions)				
Projected benefit obligation at January 1	$ 9,249	$ 8,557	$ 9,211	$ 8,551
Service cost for benefits earned	236	214	233	211
Interest cost	511	500	509	498
Plan amendments	1	(7)	3	(3)
Actuarial loss/(gain)	(592)	331	(594)	326
Benefits and expenses paid	(341)	(348)	(339)	(347)
Other [1]	-	2	-	(25)
Projected benefit obligation at December 31	$ 9,064	$ 9,249	$ 9,023	$ 9,211
Accumulated benefit obligation	$ 8,178	$ 8,276	$ 8,145	$ 8,246

[1] In 2005 a Supplemental Executive Retirement Plan was split into two plans. The Utility remained sponsor of the first plan and PG&E Corporation became the sponsor of the second plan.

Other Benefits

	PG&E Corporation		Utility	
	2006	2005	2006	2005
(in millions)				
Benefit obligation at January 1	$ 1,339	$ 1,399	$ 1,339	$ 1,399
Service cost for benefits earned	28	30	28	30
Interest cost	74	74	74	74
Actuarial gain	(105)	(103)	(105)	(103)
Participants paid benefits	31	30	31	30
Plan amendments	31	-	31	-
Gross benefits paid	(92)	(91)	(92)	(91)
Federal subsidy on benefits paid	4	-	4	-
Benefit obligation at December 31	$ 1,310	$ 1,339	$ 1,310	$ 1,339

During 2006, PG&E Corporation and the Utility began including the effects of the federal subsidy under the Medicare Prescription Drug, Improvement and Modernization Act of 2003 in measuring the benefit obligation and the net period benefit cost for the contributory defined benefit medical plans . The net subsidy that will be received by PG&E Corporation and the Utility is used to lower participant premium contributions. The result is a plan amendment increasing the benefit obligation by approximately $31 million and an offsetting actuarial gain of approximately $31 million during 2006, resulting in a zero net effect to the benefit obligation. The federal subsidy had an immaterial effect on the net periodic benefit cost in 2006.

Change in Plan Assets

To determine the fair value of the plan assets, PG&E Corporation and the Utility use publicly quoted market values and independent pricing services depending on the nature of the assets, as reported by the trustee.

The following tables reconcile aggregate changes in plan assets during 2006 and 2005:

Pension Benefits

	PG&E Corporation		Utility	
	2006	2005	2006	2005
(in millions)				
Fair value of plan assets at January 1	$ 8,049	$ 7,614	$ 8,049	$ 7,614

Actual return on plan assets	1,050	758	1,050	758
Company contributions	300	25	298	24
Benefits and expenses paid	(371)	(348)	(369)	(347)
Fair value of plan assets at December 31	$ 9,028	$ 8,049	$ 9,028	$ 8,049

Other Benefits

	PG&E Corporation		Utility	
	2006	**2005**	**2006**	**2005**
(in millions)				
Fair value of plan assets at January 1	$ 1,146	$ 1,069	$ 1,146	$ 1,069
Actual return on plan assets	154	86	154	86
Company contributions	25	59	25	59
Plan participant contribution	31	30	31	30
Benefits and expenses paid	(100)	(98)	(100)	(98)
Fair value of plan assets at December 31	$ 1,256	$ 1,146	$ 1,256	$ 1,146

Funded Status

The following schedule reconciles the plans' aggregate funded status to the prepaid or accrued benefit cost on a plan sponsor basis. The funded status is the difference between the fair value of plan assets and projected benefit obligations.

Pension Benefits

	PG&E Corporation		Utility	
	December 31,		December 31,	
	2006	**2005**	**2006**	**2005**
(in millions)				
Fair value of plan assets at December 31	$ 9,028	$ 8,049	$ 9,028	$ 8,049
Projected benefit obligation at December 31	(9,064)	(9,249)	(9,023)	(9,211)
Funded status plan assets less than projected benefit obligation	(36)	(1,200)	5	(1,162)
Unrecognized prior service cost	268	321	275	327
Unrecognized net loss	318	1,314	306	1,302
Unrecognized net transition obligation	1	1	1	-
Less: transfer to accumulated other comprehensive income [(2)]	(587)	-	(582)	-
Prepaid/(accrued) benefit cost	$ (36)	$ 436	$ 5	$ 467
Noncurrent Asset	$ 34	$ -	$ 34	$ -
Current Liability	(5)	-	(3)	-
Noncurrent liability	(65)	-	(26)	-
Prepaid benefit cost	-	491	-	491
Accrued benefit liability	-	(55)	-	(24)
Additional minimum liability	-	(671)	-	(668)
Intangible asset	-	332	-	332
Excess additional minimum liability [(1)]	-	339	-	336
Prepaid/(accrued) benefit cost	$ (36)	$ 436	$ 5	$ 467

[(1)] Of this amount, approximately $325 million has been recorded as a reduction to a pension regulatory liability in accordance with the

provisions of SFAS No. 71 and the remainder is recorded to other comprehensive income, net of the related income tax benefit, for 2005.
(2) Under SFAS No. 158 this amount is recorded to accumulated other comprehensive income, net of the related income tax benefit, for 2006.

Other Benefits

	PG&E Corporation	Utility

	December 31,		December 31,	
	2006	2005	2006	2005
(in millions)				
Fair value of plan assets at December 31	$ 1,256	$ 1,146	$ 1,256	$ 1,146
Benefit obligation at December 31	(1,310)	(1,339)	(1,310)	(1,339)
Funded status plan assets less than benefit obligation	(54)	(193)	(54)	(193)
Unrecognized prior service cost	114	132	114	132
Unrecognized net gain	(250)	(129)	(250)	(129)
Unrecognized net transition obligation	154	179	154	179
Less: transfer to accumulated other comprehensive income [1]	(18)	-	(18)	-
Accrued benefit cost	$ (54)	$ (11)	$ (54)	$ (11)
Noncurrent liability	$ (54)	$ -	$ (54)	$ -
Accrued benefit liability	-	(11)	-	(11)
Accrued benefit cost	$ (54)	$ (11)	$ (54)	$ (11)

[1] Under SFAS No. 158 this amount is recorded to accumulated other comprehensive income, net of the related income tax benefit, for 2006.

Other Information

The aggregate projected benefit obligation, accumulated benefit obligation and fair value of plan asset for plans in which the fair value of plan assets is less than the accumulated benefit obligation and the projected benefit obligation as of December 31, 2006 and 2005 were as follows:

	Pension Benefits		Other Benefits	
	2006	2005	2006	2005
(in millions)				
PG&E Corporation:				
Projected benefit obligation	$ (70)	$ (9,249)	$ (1,310)	$ (1,339)
Accumulated benefit obligation	(62)	(8,276)	-	-
Fair value of plan assets	-	8,049	1,256	1,146
Utility:				
Projected benefit obligation	$ (29)	$ (9,211)	$ (1,310)	$ (1,339)
Accumulated benefit obligation	(28)	(8,246)	-	-
Fair value of plan assets	-	8,049	1,256	1,146

Components of Net Periodic Benefit Cost

Net periodic benefit cost as reflected in PG&E Corporation's Consolidated Statements of Income for 2006, 2005 and 2004 is as follows:

Pension Benefits

	December 31,		
	2006	2005	2004
(in millions)			
Service cost for benefits earned	$ 236	$ 214	$ 194
Interest cost	511	500	482
Expected return on plan assets	(640)	(623)	(563)
Amortized prior service cost	56	56	63
Amortization of unrecognized loss	22	29	6
Net periodic benefit cost	$ 185	$ 176	$ 182

Other Benefits

	December 31,

(in millions)	2006	2005	2004
Service cost for benefits earned	$ 28	$ 30	$ 32
Interest cost	74	74	84
Expected return on plan assets	(90)	(85)	(76)
Amortized prior service cost	14	11	12
Amortization of unrecognized loss (gain)	(3)	(1)	-
Amortization of transition obligation	26	26	26
Net periodic benefit cost	$ 49	$ 55	$ 78

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

Components of Accumulated Other Comprehensive Income

On December 31, 2006, upon adoption of SFAS No. 158, PG&E Corporation and the Utility recorded unrecognized prior service costs, unrecognized gains and losses, and unrecognized net transition obligations as components of accumulated other comprehensive income, net of tax. In subsequent years PG&E Corporation and the Utility will recognize these amounts as components of net periodic benefit cost in accordance with SFAS No. 87 and 106.

Amounts recognized in accumulated other comprehensive income consist of:

	PG&E Corporation		Utility	
(in millions)	2006	2005	2006	2005
Pension Benefits:				
Unrecognized prior service cost	$ 268	$ -	$ 275	$ -
Unrecognized net loss	318	-	306	-
Unrecognized net transition obligation	1	-	1	-
Less: transfer to regulatory account [1]	(574)	-	(574)	-
Total	$ 13	$ -	$ 8	$ -
Other Benefits:				
Unrecognized prior service cost	$ 114	$ -	$ 114	$ -
Unrecognized net gain	(250)	-	(250)	-
Unrecognized net transition obligation	154	-	154	-
Total	$ 18	$ -	$ 18	$ -

[1] The Utility recorded approximately $574 million as a reduction to the existing pension regulatory liability in accordance with the provisions of SFAS No. 71.

The estimated amounts that will be amortized into net periodic benefit cost in 2007 are as follows:

(in millions)	PG&E Corporation	Utility
Pension benefits *:*		
Unrecognized prior service cost	$ 49	$ 50
Unrecognized net loss	1	-
Unrecognized net transition obligation	1	1
Total	$ 51	$ 51
Other benefits:		
Unrecognized prior service cost	$ 14	$ 14

Unrecognized net gain	(12)	(12)
Unrecognized net transition obligation	26	26
Total	$ 28	$ 28

Incremental effect of applying SFAS No. 158

The following table shows the incremental effect of applying SFAS No. 158 on individual line items in the December 31, 2006 balance sheet:

	PG&E Corporation			Utility		
(in millions)	Before Application	Effect of Adopting SFAS No. 158	As Reported at December 31, 2006	Before Application	Effect of Adopting SFAS No. 158	As Reported at December 31, 2006
Other Noncurrent Assets						
Other	$ 339	$ 34	$ 373	$ 246	$ 34	$ 280
Total other noncurrent assets	7,117	34	7,151	7,049	34	7,083
TOTAL ASSETS	$ 34,769	$ 34	$ 34,803	$ 34,337	$ 34	$ 34,371
Current Liabilities						
Accounts payable:						
Other	$ 454	$ (34)	$ 420	$ 436	$ (34)	$ 402
Deferred income taxes	134	14	148	104	14	118
Total current liabilities	8,270	(20)	8,250	7,700	(20)	7,680
Noncurrent Liabilities						
Regulatory liabilities	3,966	(574)	3,392	3,966	(574)	3,392
Deferred income taxes	2,862	(22)	2,840	2,993	(21)	2,972
Other	1,392	661	2,053	1,263	659	1,922
Total noncurrent liabilities	18,425	65	18,490	18,427	64	18,491
Accumulated other comprehensive income	(8)	(11)	(19)	(6)	(10)	(16)
Total shareholders' equity	7,822	(11)	7,811	8,210	(10)	8,200
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 34,769	$ 34	$ 34,803	$ 34,337	$ 34	$ 34,371

Valuation Assumptions

The following actuarial assumptions were used in determining the projected benefit obligations and the net periodic cost. Weighted average, year-end assumptions were used in determining the plans' projected benefit obligations, while prior year-end assumptions are used to compute net benefit cost.

	Pension Benefits			Other Benefits		
	December 31,			December 31,		
	2006	2005	2004	2006	2005	2004
Discount rate	5.90%	5.60%	5.80%	5.50 - 6.00%	5.20 - 5.65%	5.80%
Average rate of future compensation increases	5.00%	5.00%	5.00%	-	-	-
Expected return on plan assets						
Pension benefits	8.00%	8.00%	8.10%	-	-	-
Other benefits:						
Defined benefit—medical plan bargaining	-	-	-	8.20%	8.40%	8.50%
Defined benefit—medical plan non-bargaining	-	-	-	7.30%	7.60%	7.60%
Defined benefit—life insurance plan	-	-	-	8.20%	8.40%	8.50%

The assumed health care cost trend rate for 2006 is approximately 9%, decreasing gradually to an ultimate trend rate in 2011 and beyond of approximately 5%. A one-percentage point change in assumed health care cost trend rate would have the following effects:

(in millions)	One-Percentage Point Increase	One-Percentage Point Decrease
Effect on postretirement benefit obligation	$ 71	$ (58)

Effect on service and interest cost	8	(6)	

Expected rates of return on plan assets were developed by determining projected stock and bond returns and then applying these returns to the target asset allocations of the employee benefit trusts, resulting in a weighted average rate of return on plan assets. Fixed income returns were projected based on real maturity and credit spreads added to a long-term inflation rate. Equity returns were estimated based on estimates of dividend yield and real earnings growth added to a long-term rate of inflation. For the Utility Retirement Plan, the assumed return of 8.0% compares to a ten-year actual return of 9.0%. The rate used to discount pension and other post-retirement benefit plan liabilities was based on a yield curve developed from market data of over 500 Aa-grade non-callable bonds at December 31, 2006. This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other benefit obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

The difference between actual and expected return on plan assets is included in net amortization and deferral, and is considered in the determination of future net benefit income (cost). The actual return on plan assets was above the expected return in 2006, 2005 and 2004.

Asset Allocations

The asset allocation of PG&E Corporation's and the Utility's pension and other benefit plans at December 31, 2006 and 2005, and target 2007 allocation, were as follows:

	Pension Benefits			Other Benefits		
	2007	2006	2005	2007	2006	2005
Equity securities						
U.S. equity	37.5%	38%	41%	49%	49%	51%
Non-U.S. equity	17.5%	18%	24%	18%	20%	20%
Global equity	5%	5%	0%	4%	4%	0%
Fixed income securities	40%	39%	35%	29%	27%	29%
Total	100%	100%	100%	100%	100%	100%

Equity securities include a small amount (less than 0.1% of total plan assets) of PG&E Corporation common stock.

The maturity of fixed income securities at December 31, 2006 ranged from zero to 60 years and the average duration of the bond portfolio was approximately 4.6 years. The maturity of fixed income securities at December 31, 2005 ranged from zero to 55 years and the average duration of the bond portfolio was approximately 4.1 years.

PG&E Corporation's and the Utility's investment strategy for all plans is to maintain actual asset weightings within 0.5% - 5.5% of target asset allocations varying by asset class. A rebalancing review is triggered whenever the actual weighting exceeds the range of acceptable weighting.

A benchmark portfolio for each asset class is set based on market capitalization and valuations of equities and the durations and credit quality of fixed income securities. Investment managers for each asset class are retained to periodically adjust, or actively manage, the combined portfolio against the benchmark. Active management covers approximately 80% of the U.S. equity, 55% of the non-U.S. equity, and virtually 100% of the fixed income and global security portfolios.

Cash Flow Information

Employer Contributions

PG&E Corporation and the Utility contributed approximately $300 million to the pension benefits, including $295 million to the qualified defined benefit pension plan, of which $20 million related to 2005, and approximately $25 million to the other benefits in 2006. These 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 federal minimum funding requirements. None of these pension or other benefits were subject to a minimum funding requirement in 2006. The Utility's pension benefits met all the funding requirements under the Employee Retirement Income Security Act of 1974, as amended. PG&E Corporation and the Utility expect to make total contributions of approximately $176 million during 2007 to the qualified defined benefit pension plan. Contribution estimates for the Utility's other benefit plans after 2006 will be driven by future GRC decisions and in line with the Utility’s funding policy.

Benefits Payments

The estimated benefits expected to be paid in each of the next five fiscal years and in aggregate for the five fiscal years thereafter, are as follows:

(in millions)	PG&E Corporation	Utility
Pension		
2007	$ 392	$ 390
2008	417	415
2009	441	439
2010	465	462
2011	511	508
2012-2016	2,771	2,757
Other benefits		
2007	$ 80	$ 80
2008	84	84
2009	86	86
2010	89	89
2011	91	91
2012-2016	484	484

Defined Contribution Pension Plan

PG&E Corporation and its subsidiaries also sponsor defined contribution benefit plans. These plans are qualified under applicable sections of the Internal Revenue Code. These plans provide for tax-deferred salary deductions and after-tax employee contributions as well as employer contributions. Employees designate the funds in which their contributions and any employer contributions are invested. Employer contributions include matching of up to 5% of an employee's base compensation and/or basic contributions of up to 5% of an employee's base compensation. Matching employer contributions are automatically invested in PG&E Corporation common stock. Employees may reallocate matching employer contributions and accumulated earnings thereon to another investment fund or funds available to the plan at any time after they have been credited to the employee’s account. Employer contribution expense reflected in PG&E Corporation's Consolidated Statements of Income amounted to:

(in millions)	PG&E Corporation	Utility
Year ended December 31,		
2006	$ 45	$ 43
2005	43	42
2004 [(1)]	40	39

[(1)] Includes NEGT-related amounts within PG&E Corporation.

LONG-TERM INCENTIVE PLAN

On January 1, 2006, the PG&E Corporation 2006 LTIP became effective. The 2006 LTIP permits the award of various forms of incentive awards, including stock options, stock appreciation rights, restricted stock awards, restricted stock units, performance shares, performance units, deferred compensation awards, and other stock-based awards, to eligible employees of PG&E Corporation and its subsidiaries. Non-employee directors of PG&E Corporation are also eligible to receive restricted stock and either stock options or restricted stock units under the formula grant provisions of the 2006 LTIP. A maximum of 12 million shares of PG&E Corporation common stock (subject to adjustment for changes in capital structure, stock dividends, or other similar events) have been reserved for issuance under the 2006 LTIP, of which 11,421,085 shares were available for award at December 31, 2006. The 2006 LTIP was amended on February 15, 2006 to address the vesting of outstanding awards in connection with a change in control of PG&E Corporation.

The 2006 LTIP replaced the PG&E Corporation Long-Term Incentive Program, which expired on December 31, 2005. Awards made under the PG&E Corporation Long-Term Incentive Program before December 31, 2005 and still outstanding continue to be governed by the terms and conditions of the PG&E Corporation Long-Term Incentive Program.

PG&E Corporation and the Utility use an estimated annual forfeiture rate of 2%, based on historic forfeiture rates, for purposes of determining compensation expense for share-based incentive awards. The following table provides a summary of total compensation expense for PG&E Corporation (consolidated) and the Utility (stand-alone) for share-based incentive awards for the year ended December 31, 2006:

(in millions)	PG&E Corporation	Utility
Stock Options	$ 12	$ 8
Restricted Stock	20	14
Performance Shares	33	24
Total Compensation Expense (pre-tax)	$ 65	$ 46
Total Compensation Expense (after-tax)	$ 39	$ 27

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

Stock Options

Other than the grant of options to purchase 12,457 shares of PG&E Corporation common stock to non-employee directors of PG&E Corporation in accordance with the formula and nondiscretionary provisions of the 2006 LTIP, no other stock options were granted during 2006. The exercise price of stock options granted under the 2006 LTIP and all other outstanding stock options is equal to the market price of PG&E Corporation’s common stock on the date of grant. Stock options generally have a ten-year term and vest over four years of continuous service, subject to accelerated vesting in certain circumstances.

The fair value of each stock option on the date of grant is estimated using the Black-Scholes valuation method. The weighted average grant date fair value of options granted using the Black-Scholes valuation method was $6.98, $10.08, and $8.70 per share in 2006, 2005, and 2004, respectively. The significant assumptions used for shares granted in 2006, 2005, and 2004 were:

	2006	2005	2004
Expected stock price volatility	22.1%	40.6%	45.0%
Expected annual dividend payment	$ 1.32	$ 1.20	$ 1.20
Risk-free interest rate	4.46%	3.74%	3.66%
Expected life	5.6 years	5.9 years	6.5 years

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

The following table summarizes total intrinsic value (fair market value of PG&E Corporation’s stock less stock option strike price) of options exercised for PG&E Corporation (consolidated) and the Utility (stand-alone) in 2006, 2005, and 2004:

(in millions)	PG&E Corporation	Utility
2006:		
Intrinsic value of options exercised	$ 97	$ 51
2005:		
Intrinsic value of options exercised	$ 125	$ 57
2004:		
Intrinsic value of options exercised	$ 83	$ 44

The tax benefit from stock options exercised totaled $31 million for the year ended December 31, 2006, of which approximately $44 million was recorded by the Utility.

The following table summarizes stock option activity for PG&E Corporation and the Utility for 2006:

Options	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1	11,899,059	$ 23.26		
Granted [1]	12,457	37.47		
Exercised	(5,369,818)	22.05		
Forfeited or expired	(142,728)	25.50		
Outstanding at December 31	6,398,970	23.52	5.5	$ 148,248,308
Expected to vest at December 31	2,226,843	25.29	6.9	$ 46,872,341
Exercisable at December 31	4,115,402	17.50	3.8	$ 101,375,967

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

The following table summarizes stock option activity for the Utility for 2006:

Options	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1 [1]	7,344,455	$ 23.15		
Granted	-	-		
Exercised	(2,836,769)	22.21		
Forfeited or expired	(105,180)	25.48		
Outstanding at December 31	4,402,506	23.66	5.8	$ 104,083,574
Expected to vest at December 31	1,571,779	25.28	6.9	$ 33,113,132
Exercisable at December 31	2,799,712	17.99	4.1	$ 70,970,442

[1] Includes net employee transfers between PG&E Corporation and the Utility during 2006.

As of December 31, 2006, there was approximately $16 million of total unrecognized compensation cost related to outstanding stock options, of which $11 million was allocated to the Utility. That cost is expected to be recognized over a weighted average period of 2.4 years for PG&E Corporation and the Utility.

Restricted Stock

During 2006, PG&E Corporation awarded 559,855 shares of PG&E Corporation restricted common stock to eligible participants of PG&E Corporation and its subsidiaries, of which 387,735 shares were awarded to the Utility's eligible participants.

The restricted shares are held in an escrow account. The shares become available to the employees as the restrictions lapse. For the restricted stock awarded in 2003, the restrictions on 80% of the shares lapse automatically over a period of four years at the rate of 20% per year. Restrictions on the remaining 20% of the shares will lapse at a rate of 5% per year if PG&E Corporation's annual total shareholder return, or TSR, is in the top quartile of its comparator group as measured at the end of the immediately preceding year. For restricted stock awarded in 2004 and 2005, there are no performance criteria and the restrictions will lapse ratably over four years. For restricted stock awarded in 2006, the restrictions on 60% of the shares will lapse automatically over a period of three years at the rate of 20% per year. If PG&E Corporation's annual TSR is in the top quartile of its comparator group, as measured for the three immediately preceding calendar years, the restrictions on the remaining 40% of the shares will lapse on the first business day of 2009. If PG&E Corporation's TSR is not in the top quartile for such period,

then the restrictions on the remaining 40% of the shares will lapse on the first business day of 2011. Compensation expense related to the portion of the 2006 restricted stock award that is subject to conditions based on TSR is recognized over the shorter of the requisite service period and three years.

The tax benefit from restricted stock which vested during 2006 totaled $4 million for 2006, of which approximately $2 million was recorded by the Utility.

The following table summarizes restricted stock activity for PG&E Corporation and the Utility for 2006:

	Number of Shares of Restricted Stock	Weighted Average Grant-Date Fair Value
Nonvested at January 1	1,399,990	$ 22.31
Granted	559,855	37.47
Vested	(493,874)	20.97
Forfeited	(88,433)	19.41
Nonvested at December 31	1,377,538	$ 29.24

The following table summarizes restricted stock activity for the Utility for 2006:

	Number of Shares of Restricted Stock	Weighted Average Grant-Date Fair Value
Nonvested at January 1	958,997	$ 22.48
Granted	387,735	37.47
Vested	(339,362)	21.08
Forfeited	(74,642)	20.74
Nonvested at December 31	932,728	$ 29.36

As of December 31, 2006, there was approximately $17 million of total unrecognized compensation cost relating to restricted stock, of which $12 million related to the Utility. PG&E Corporation and the Utility expect to recognize this cost over a weighted average period of 1.3 years.

Performance Shares and Performance Units

During 2006, PG&E Corporation awarded 559,855 performance shares to eligible participants of PG&E Corporation and its subsidiaries, of which 387,735 shares were awarded to the Utility's eligible participants. Performance shares are hypothetical shares of PG&E Corporation common stock that vest at the end of a three-year period and are settled in cash. Upon vesting, the amount of cash that recipients are entitled to receive is based on the average closing price of PG&E Corporation stock for the last 30 calendar days of the year preceding the vesting date and a payout percentage, ranging from 0% to 200%, as measured by PG&E Corporation's TSR relative to its comparator group for the applicable three-year period.

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

The following table summarizes performance share activity for PG&E Corporation and the Utility for 2006:

	Number of Performance Shares
Nonvested at January 1	803,975
Granted	559,855

Vested	(469,023)
Forfeited	(62,201)
Nonvested at December 31	832,606

The following table summarizes performance shares activity for the Utility for 2006:

	Number of Performance Shares

Nonvested at January 1	566,086
Granted	387,735
Vested	(319,119)
Forfeited	(51,105)
Nonvested at December 31	583,597

PG&E Corporation Supplemental Retirement Savings Plan

The supplemental retirement savings plan provides supplemental retirement alternatives to eligible officers and key employees of PG&E Corporation and its subsidiaries by allowing participants to defer portions of their compensation, including salaries and amounts awarded under various incentive awards and to receive supplemental employer-provided retirement benefits. Under the employee-elected deferral component of the plan, eligible employees may defer all or part of their incentive awards and 5% to 50% of their salary. Under the supplemental employer-provided retirement benefits component of the plan, eligible employees may receive full credit for employer matching and basic contributions, under the respective defined contribution plan, in excess of limitations set by the Internal Revenue Code. A separate non-qualified account is maintained for each eligible employee to track deferred amounts. The account's value is adjusted in accordance with the performance of the investment options selected by the employee. Each employee's account is adjusted on a quarterly basis, and the change in value is recorded as additional compensation expense or income in the Consolidated Financial Statements. Total compensation expense recognized by PG&E Corporation and the Utility in connection with the plan amounted to:

(in millions)	PG&E Corporation	Utility
2006:	$ 4	$ 2
2005:	3	1
2004:	3	1

NOTE 15: 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.

The Utility emerged from Chapter 11 when its plan of reorganization became effective on April 12, 2004, or the Effective Date. The plan of reorganization incorporated the terms of the Chapter 11 Settlement Agreement. Although the Utility's operations are no longer subject to the oversight of the bankruptcy court, the bankruptcy court retains jurisdiction to hear and determine disputes arising in connection with the interpretation, implementation or enforcement of (1) the Chapter 11 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.

At December 31, 2004, the Utility had accrued approximately $2.1 billion for remaining disputed claims. Since December 31, 2004, the Utility has made payments to creditors of approximately $29 million in settlement of disputed claims and, as a result of settlements reached with creditors, has reduced the disputed claims balance by approximately $404 million. The Utility held $1.2 billion in escrow for the payment of the remaining disputed claims as of December 31, 2006. Upon resolution of these claims and under the terms of the Chapter 11 Settlement Agreement, any net refunds, claim 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 CAISO and Power Exchange, or PX, sellers. As of December 31, 2006, the amount of the accrual was approximately $1.2 billion for remaining net disputed claims, consisting of approximately $1.7 billion of accounts payable-disputed claims primarily payable to the CAISO and the PX, offset by an accounts receivable from the CAISO and the PX of approximately $0.5 billion.

NOTE 16: RELATED PARTY AGREEMENTS AND TRANSACTIONS

In accordance with various agreements, the Utility and other subsidiaries provide and receive various services to and from their parent, PG&E Corporation, and among themselves. The Utility and PG&E Corporation exchange administrative and professional services in support of operations. Services provided directly to PG&E Corporation by the Utility are priced at the higher of fully loaded cost (i.e., direct costs and allocations of overhead costs) or fair market value, depending on the nature of the services.

Services provided directly to the Utility by PG&E Corporation are priced at the lower of fully loaded cost or fair market value, depending on the nature of the services. PG&E Corporation also allocates certain other corporate administrative and general costs, at cost, to the Utility and other subsidiaries using agreed upon allocation factors, including the number of employees, operating expenses excluding fuel purchases, total assets and other cost allocation methodologies. The Utility's significant related party transactions and related receivable (payable) balances were as follows:

	Year Ended December 31,			Receivable (Payable) Balance Outstanding at Year Ended December 31,	
	2006	2005	2004	2006	2005
(in millions)					
Utility revenues from:					
Administrative services provided to PG&E Corporation	$ 5	$ 5	$ 8	$ 2	$ 2
Utility employee benefit assets due from PG&E Corporation	-	-	-	25	23
Interest from PG&E Corporation on employee benefit assets	1	-	-	-	-
Utility expenses from:					
Administrative services received from PG&E Corporation	$ 108	$ 111	$ 81	$ (40)	$ (37)
Utility employee benefit payments due to PG&E Corporation	3	-	-	-	-
Interest accrued on pre-petition liabilities due to PG&E Corporation	-	-	2	-	-
Natural gas transportation services received from GTNW	-	-	43	-	-

NOTE 17: COMMITMENTS AND CONTINGENCIES

PG&E Corporation and the Utility have substantial financial commitments in connection with agreements entered into to support the Utility's operating activities. PG&E Corporation has no ongoing financial commitments relating to NEGT's current operating activities. PG&E Corporation and the Utility also have significant contingencies arising from their operations, including contingencies related to guarantees, power purchases made during the 2001-2001 energy crisis, regulatory proceedings, nuclear operations, employee matters, environmental compliance and remediation and legal matters.

Commitments

PG&E Corporation

PG&E Corporation agreed to accept the assignment of certain Canadian natural gas pipeline firm transportation contracts effective November 1, 2007, through October 31, 2023, the remaining term of the contracts' duration. The firm quantity under the contracts is approximately 50 million cubic feet per day and PG&E Corporation has estimated annual reservation charges will range between approximately $8 million and $12 million. During the term of the contracts, the applicable reservation charges will equal the full tariff rates set by regulatory authorities in Canada and the United States, as applicable. PG&E Corporation is unable to predict the utilization of these contracts, which will depend on market prices, customer demand and approval of cost recovery by the CPUC among other factors.

PG&E Corporation also has operating lease obligations related to office space. Contracts have expiration terms that range from November 2008 to February 2012. PG&E’s commitment under these contracts is approximately $13 million.

Utility

Third Party Power Purchase Agreements

Qualifying Facility Power Purchase Agreements - Under the Public Utility Regulatory Policies Act of 1978, or PURPA, electric utilities were required to purchase energy and capacity from independent power producers that are qualifying co-generation facilities, or QFs. To implement the purchase requirements of PURPA, the CPUC required California investor-owned electric utilities to enter into long-term power purchase agreements with QFs and approved the applicable terms, conditions, prices and eligibility requirements. These agreements require the Utility to pay for energy and capacity. Energy payments are based on the QF's actual electrical output and CPUC-approved energy prices, while

capacity payments are based on the QF's total available capacity and

contractual capacity commitment. Capacity payments may be adjusted if the QF fails to meet or exceeds performance requirements specified in the applicable power purchase agreement.

The Energy Policy Act of 2005 significantly amended the purchase requirements of PURPA. As amended, Section 210(m) of PURPA authorizes the FERC to waive the obligation of an electric utility under Section 210 of PURPA to purchase the electricity offered to it by a QF (under a new contract or obligation) if the FERC finds that the QF has nondiscriminatory access to one of three defined categories of competitive wholesale electricity markets. The statute permits such waivers as to a particular QF or on a "service territory-wide basis." The Utility plans to wait until after the new day-ahead market structure provided for in the CAISO's Market Redesign and Technology Update, or MRTU, initiative to restructure the California electricity market becomes effective to assess whether it will file a request with the FERC to terminate its obligations under PURPA to enter into new QF purchase obligations.

As of December 31, 2006, the Utility had agreements with 268 QFs for approximately 4,150 megawatts, or MW, that are in operation. Agreements for approximately 3,800 MW expire at various dates between 2007 and 2028. QF power purchase agreements for approximately 350 MW have no specific expiration dates and will terminate only when the owner of the QF exercises its termination option. The Utility also has power purchase agreements with approximately 68 inoperative QFs. The total of approximately 4,150 MW consists of approximately 2,550 MW from cogeneration projects, 600 MW from wind projects and 1,000 MW from projects with other fuel sources, including biomass, waste-to-energy, geothermal, solar and hydroelectric.

QF power purchase agreements accounted for approximately 20% of the Utility's 2006 electricity sources, 22% of the Utility's 2005 electricity sources and approximately 23% of the Utility's 2004 electricity sources. No single QF accounted for more than 5% of the Utility's 2006, 2005 or 2004 electricity sources.

There are proceedings pending at the CPUC that may impact the amount of payments to QFs, the number of QFs holding power purchase agreements with the Utility, as well as the outcome of the Utility's request for refunds for overpayments from June 2000 through March 2001 that were made to QFs pursuant to CPUC orders at approved rates. The CPUC will address whether certain payments for short-term power deliveries required by the power purchase agreements comply with the pricing requirements of PURPA. The CPUC is also considering whether to require the California investor-owned electric utilities to enter into new power purchase agreements with existing QFs that have expiring power purchase agreements and with newly-constructed QFs and if so, specify the appropriate level of compensation for power purchased under such new agreements. PG&E Corporation and the Utility are unable to predict the outcome of these proceedings.

The CPUC is considering various policy and pricing issues related to power purchased from QFs in several rulemaking proceedings. It is expected that a proposed decision addressing those issues will be issued soon. In April 2006, the Utility and the Independent Energy Producers, or IEP, on behalf of certain QFs, entered into a settlement agreement to resolve these issues irrespective of how the CPUC ultimately resolves these issues. These issues, however, remain unresolved for the QFs that did not accept the terms of the settlement agreement. In July 2006, the CPUC approved the IEP settlement agreement and the QF amendments which implement the agreement with the settling QFs. As of December 31, 2006, 122 QFs were subject to such amendments of their existing contracts with the Utility which reduce the Utility's energy payments and establish a new five-year fixed pricing option for QFs that do not use natural gas as their fuel source. The IEP settlement agreement also resolves certain energy crisis claims among the Utility and the settling QFs that are pending in another CPUC proceeding. When a final decision addressing these issues is issued by the CPUC, the Utility will re-evaluate the accounting treatment for QF contracts that are affected by the decision.

As a result of the amendments, several of the QF contracts became subject to lease accounting under SFAS No. 13, "Accounting for Leases," or SFAS No. 13, due to the nature of the fixed capacity payments. SFAS No. 13 requires the Utility to recognize capital lease obligations and assets equal to the present value of the fixed capacity payments under the QF agreements that are treated as capital leases. Accordingly, the Utility's Consolidated Balance Sheet has included in Current Liabilities - Other and Noncurrent Liabilities - Other of approximately $27 million and $372 million, respectively, as of December 31, 2006, representing the present value of the fixed capacity payments due under these contracts. The corresponding assets of $399 million, including amortization of $9 million, are included in plant, property and equipment on the Utility's Consolidated Balance Sheet at December 31, 2006.

In accordance with the settlement between the Utility and Mirant Corporation and certain of its subsidiaries, or Mirant, related to claims outstanding in Mirant's Chapter 11 proceeding, the Utility entered into contracts with several of Mirant's units in the Utility's service territory. In July 2006, the Utility and Mirant entered into two new contracts, which both supplemented and partially superseded the contracts from the settlement, resulting in further savings for the Utility's customers. The new contracts, one for 2007 and one for a multi-year period beginning in January 2008, give the Utility the right to dispatch power from 1,985 MW of units owned by Mirant subsidiaries to meet local reliability and peak period energy needs. In August 2006, the Utility filed an advice letter seeking CPUC approval for the multi-year contract and expects possible action during the first quarter of 2007.

Irrigation Districts and Water Agencies - The Utility has contracts with various irrigation districts and water agencies to purchase hydroelectric power. Under these contracts, the Utility must make specified semi-annual minimum payments based on the irrigation districts' and water agencies' debt service requirements, whether or not any hydroelectric power is supplied, and variable payments for operation and maintenance costs incurred by the suppliers. These contracts expire on various dates from 2007 to 2031. The Utility's irrigation district and water agency contracts accounted for approximately 6% of the Utility's 2006 electricity sources, approximately 5% of the Utility's 2005 and 2004 electricity sources.

Renewable Energy Contracts - California law requires that each California retail seller of electricity, except for municipal utilities, increase its purchases of renewable energy (such as biomass, wind, solar and geothermal energy) by at least 1% of its retail sales per year, so that the amount of electricity purchased from renewable resources equals at least 20% of its total retail sales by the end of 2010. During 2006, the Utility entered into several new renewable power purchase contracts that will help the Utility meet its goals.

Long Term Power Purchase Agreements - After competitive solicitations, bilateral negotiations and request for offers or proposals were conducted, the Utility entered into several agreements with third party power providers d uring 2006 to meet the Utility's intermediate and long-term generation resource needs. Under these agreements, the Utility will purchase power from facilities as late as 2010. These combined agreements cover an aggregate of 7,129 MW of contractual capacity that expire between December 31, 2010 and August 31, 2029. P ayments are not required under these agreements until the underlying generation facilities are operational.

Annual Receipts and Payments - The payments made under QFs, irrigation district and water agency, renewable energy and other power purchase agreements during 2004 through 2006 were as follows:

(in millions)	**2006**	**2005**	**2004**
Qualifying facility energy payments	$ 661	$ 663	$ 701
Qualifying facility capacity payments	366	372	382
Irrigation district and water agency payments	64	54	61
Renewable energy and capacity payments	429	405	406
Other power purchase agreement payments	670	774	834

Because the Utility acts as only an agent for the DWR the amounts described above do not include payments related to DWR power purchases.

At December 31, 2006, the undiscounted future expected power purchase agreement payments were as follows:

	Qualifying Facility		**Irrigation District & Water Agency**		**Renewable**		**Other**	
(in millions)	**Energy**	**Capacity**	**Operations & Maintenance**	**Debt Service**	**Energy**	**Capacity**	**Energy**	**Capacity**
2007	$ 1,195	$ 477	$ 54	$ 26	$ 148	$ 18	$ 50	$ 201
2008	1,276	468	34	4	205	21	41	169
2009	1,159	428	32	-	254	18	40	171
2010	995	391	31	-	294	14	11	158
2011	930	377	30	-	315	14	5	44
Thereafter	5,941	2,601	114	-	2,979	76	11	18
Total	$ 11,496	$ 4,742	$ 295	$ 30	$ 4,195	$ 161	$ 158	$ 761

The following table shows the future fixed capacity payments due under the QF contracts that are treated as capital leases. These amounts are also included in the table above. The fixed capacity payments are discounted to the present value shown in the table below using the Utility's incremental borrowing rate at the inception of the leases. The amount of this discount is shown in the table below as the amount representing interest.

(in millions)	
2007	$ 50
2008	50

2009	50
2010	50

2011	50
Thereafter	303
Total fixed capacity payments	553
Less: Amount representing interest	154
Present value of fixed capacity payments	$ 399

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

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

Natural Gas Supply and Transportation Commitments

The Utility purchases natural gas directly from producers and marketers in both 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 December 31, 2006, the Utility's undiscounted obligations for natural gas purchases and gas transportation services were as follows:

(in millions)	
2007	$ 954
2008	151
2009	25
2010	8
2011	-
Thereafter	-
Total	$ 1,138

Payments for natural gas purchases and gas transportation services amounted to approximately $2.2 billion in 2006, $2.5 billion in 2005 and $1.8 billion in 2004.

Nuclear Fuel Agreements

The Utility has entered several purchase agreements for nuclear fuel. These agreements have terms ranging from two to five years and are intended to ensure long-term fuel supply. A total of five new contracts were executed in 2006 for deliveries in 2006 to 2010. One existing services contract was extended for five additional years. In most cases, the Utility's nuclear fuel contracts are requirements-based. The Utility relies on established international producers of nuclear fuel in order to diversify its sources and provide security of supply. Pricing terms also are diversified, ranging from fixed prices to market-based prices to base prices that are escalated using published indices.

At December 31, 2006, the undiscounted obligations under nuclear fuel agreements were as follows:

(in millions)	
2007	$ 135
2008	86
2009	66
2010	64
2011	37
Thereafter	151
Total	$ 539

Payments for nuclear fuel amounted to approximately $106 million in 2006, $65 million in 2005 and $119 million in 2004.

The CAISO has entered into reliability must run, or RMR, agreements with various power plant owners, including the Utility, that require designated units in certain power plants, known as RMR units, to remain available to generate electricity upon the CAISO's demand when needed for local transmission system reliability. As a participating transmission owner under the Transmission Control Agreement, the Utility is responsible for the CAISO's costs paid under RMR agreements to power plant owners within or adjacent to the Utility's service territory. RMR agreements are established or extended on an annual basis. During 2006, the CPUC adopted rules to implement state law requirements for California investor-owned utilities to meet resource adequacy requirements, including rules to address local transmission system reliability issues. As the utilities fulfill their responsibility to meet these requirements, the number of RMR agreements with the CAISO and the associated costs will decline. At December 31, 2006, the Utility estimated that it could be obligated to pay the CAISO approximately $75 million for costs to be incurred under these RMR agreements during 2007. The Utility recovers these costs from customers.

In October 2006, the Utility, the California Electricity Oversight Board, and certain other owners of RMR plants, entered into a settlement agreement to resolve complaints that these RMR plant owners charged excessive rates. The settlement agreement has been approved by the CPUC, the FERC, and the bankruptcy court adjudicating the Chapter 11 proceedings of some of the RMR plant owners. The Utility expects that it will receive refunds of approximately $61 million for amounts paid under RMR contracts in 2006 in the first quarter of 2007. Any refunds would be credited to the Utility’s electricity customers.

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, energy efficiency programs and telecommunication contracts. At December 31, 2006, the future minimum payments related to other commitments were as follows:

(in millions)	
2007	$ 160
2008	33
2009	18
2010	12
2011	11
Thereafter	34
Total	$ 268

Payments for other commitments amounted to approximately $100 million in 2006, $146 million in 2005 and $111 million in 2004.

Underground Electric Facilities

At December 31, 2006, the Utility was committed to spending approximately $211 million for the conversion of existing overhead electric facilities to underground electric facilities. These funds are conditionally committed depending on the timing of the work, including the schedules of the respective cities, counties and telephone utilities involved. The Utility expects to spend approximately $50 million to $60 million each year in connection with these projects. Consistent with past practice, the Utility expects that these capital expenditures will be included in rate base as each individual project is completed and recoverable in rates charged to customers.

Contingencies

PG&E Corporation

PG&E Corporation retains a guarantee related to certain NEGT indemnity obligations that were issued to the purchaser of an NEGT subsidiary company. PG&E Corporation's sole remaining exposure relates to any potential environmental obligations that were known to NEGT at the time of the sale but not disclosed to the purchaser and is limited to $150 million. PG&E Corporation has never received any claims nor does it consider it probable any claims will be made under the guarantee. Accordingly, PG&E Corporation has made no provision for this guarantee at December 31, 2006.

Utility

PX Block-Forward Contracts

In February 2001, during the energy crisis, the California Governor seized all of the Utility’s contracts for the forward

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

California Energy Crisis Proceedings

Several parties, including the Utility and the State of California, are seeking refunds on behalf of California electricity purchasers from electricity suppliers, including municipal and governmental entities, for overcharges incurred in the CAISO and PX wholesale electricity markets between May 2000 and June 2001 through various proceedings pending at the FERC and other judicial proceedings. Many issues raised in these proceedings, including the extent of the FERC's refund authority, and the amount of potential refunds after taking into account certain costs incurred by the electricity suppliers, have not been resolved. It is uncertain when these proceedings will be concluded.

The Utility has entered into settlements with various electricity suppliers resolving certain disputed claims and the Utility's refund claims against these electricity suppliers. The Utility has received consideration of approximately $1 billion under these settlements through cash proceeds, reductions to the Utility's PX liability and a partially constructed generating facility (Gateway). With the approval of the bankruptcy court, the Utility has withdrawn certain amounts from escrow (classified as restricted cash in the Consolidated Balance Sheets) in connection with certain of these settlements (see further discussion in Note 15). These settlement agreements provide that the amounts payable by the parties are, in some instances, subject to adjustment based on the outcome of the various issues being considered by the FERC. Additional settlement discussions with other electricity suppliers are ongoing. Future amounts received under these settlements, and any future settlements with electricity suppliers, will be credited to customers after deductions for contingencies and amounts related to certain wholesale power purchases.

PG&E Corporation and the Utility are unable to predict when the FERC proceedings will ultimately be resolved and the amount of any potential refunds the Utility may receive.

Nuclear Insurance

The Utility has several types of nuclear insurance for 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 for Diablo Canyon. In addition, NEIL provides $131 million of property damage insurance for Humboldt Bay Unit 3. Under this insurance, if any nuclear generating facility insured by NEIL suffers a catastrophic loss causing a prolonged outage, the Utility may be required to pay an additional premium of up to $41.4 million per one-year policy term.

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

Under the Price-Anderson Act, public liability claims from a nuclear incident are limited to $10.8 billion. As required by the Price-Anderson Act, the Utility purchased the maximum available public liability insurance of $300 million for Diablo Canyon. The balance of the $10.8 billion of liability protection is covered by a loss-sharing program among utilities owning nuclear reactors. Under the Price-Anderson Act, owner participation in this loss-sharing program is required for all owners of nuclear reactors that are licensed to operate, designed for the production of electrical energy, and have a rated capacity of 100 MW or higher. If a nuclear incident results in costs in excess of $300 million, then the Utility may be responsible for up to $100.6 million per reactor, with payments in each year limited to a maximum of $15 million per incident until the Utility has fully paid its share of the liability. Since Diablo Canyon has two nuclear reactors each with a rated capacity of over 100 MW, the Utility may be assessed up to $201.2 million per incident, with payments in each year limited to a maximum of $30 million per incident. Under the Energy Policy Act of 2005, the

Price-Anderson Act was extended through December 31, 2025. Both the maximum assessment per reactor and the maximum yearly assessment will be adjusted for inflation beginning August 31, 2008.

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

California Department of Water Resources Contracts

Electricity from the DWR contracts to the Utility provided approximately 24% of the electricity delivered to the Utility's customers for 2006. The DWR purchased the electricity under contracts with various generators. The Utility, as an agent, is responsible for administration and dispatch of the DWR's electricity procurement contracts allocated to the Utility for purposes of meeting a portion of the Utility's short or long position. A short position results when customer demand, plus applicable reserve margins, exceeds the amount of electricity procured from the Utility's own generation facilities, purchase contracts or DWR contracts allocated to the Utility's customers. In order to satisfy the short position, the Utility would be required to purchase electricity on the spot and forward markets, possibly at a loss. Conversely, a long position results when the contracted supply of energy exceeds customer demand. When in a long position, the Utility would be required to sell the excess capacity in the forward and spot markets, at a gain or possibly at a loss. The DWR remains legally and financially responsible for its electricity procurement contracts. The Utility acts as a billing and collection agent of the DWR's revenue requirements from the Utility's customers.

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

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

- After assumption, the Utility's issuer rating by Moody's 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.

Severance in Connection with Efforts to Achieve Cost and Operating Efficiencies

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

Estimating severance costs requires the Utility to predict whether employees will elect severance or reassignment, and the number of available vacant positions for employees wishing to be reassigned. Depending on the employees' elections, costs will further vary based on the employees' years of service and annual salary. Given the uncertainty of each of these variables, the estimated range is relatively wide. At December 31, 2006, the Utility's future severance expenses related to these initiatives are expected to range from $34 million to approximately $68 million, of which the Utility has recorded the low end as of December 31, 2006. The following table presents the changes in the liability from December 31, 2005:

(in millions)	
Balance at December 31, 2005	$ 2
Expenses	36
Less: Payments	(4)
Balance at December 31, 2006	$ 34

Environmental Matters

The Utility may be required to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party under the Comprehensive Environmental Response Compensation and Liability Act of 1980, as amended, and similar state environmental laws. These sites include former manufactured gas plant sites, power plant sites, and sites used by the Utility for the storage, recycling or disposal of potentially hazardous materials. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if the Utility did not deposit those substances on the site.

The cost of environmental remediation is difficult to estimate. The Utility records an environmental remediation liability when site assessments indicate 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. The Utility estimates the upper end of this cost range using reasonably possible outcomes that are least favorable to the Utility. It is reasonably possible that a change in these estimates may occur in the near term due to uncertainty concerning the Utility's responsibility, the complexity of environmental laws and regulations, and the selection of compliance alternatives.

The Utility had an undiscounted environmental remediation liability of approximately $511 million at December 31, 2006 and approximately $469 million at December 31, 2005. The increase in the undiscounted environmental remediation reflects an increase of $74 million for remediation at the Utility’s gas compressor stations located near Hinkley, California and Topock, Arizona. The portion of the increased liability of $39 million for remediation at the Hinkley facility is attributable to changes in the California Regional Water Quality Control Board’s imposed remediation levels. Costs incurred at this facility are not recoverable from customers and, as a result, the after-tax impact on income was a reduction of approximately $23 million for 2006. Ninety percent of the estimated remediation costs associated with the Utility’s gas compressor station located near Topock, Arizona will be recoverable in rates in accordance with the hazardous waste ratemaking mechanism which permits the Utility to recover 90% of hazardous waste remediation costs from customers without a reasonableness review.

The $511 million accrued at December 31, 2006 includes:

- approximately $238 million for remediation at the Hinkley and Topock natural gas compressor sites;
- approximately $98 million related to the pre-closing remediation liability associated with divested generation facilities; and
- approximately $175 million related to remediation costs for the Utility’s generation facilities and gas gathering sites, third-party disposal sites, and manufactured gas plant sites owned by the Utility or third parties (including those sites that are the subject of remediation orders by environmental agencies or claims by the current owners of the former manufactured gas plant sites).

Of the approximately $511 million environmental remediation liability, approximately $138 million has been included in prior rate setting proceedings. The Utility expects that an additional amount of approximately $272 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 $782 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 $782 million does not include any estimate for any potential costs of remediation at former manufactured gas plant sites in the Utility's service territory that were previously owned by the Utility or a predecessor but that are now owned by others because the Utility either has not been able to determine if a liability exists with respect to these sites or the Utility has not been able to estimate the amount of any future potential remediation costs that may be incurred for these sites.

In July 2004, the U.S. Environmental Protection Agency, or EPA, published regulations under Section 316(b) of the Clean Water Act for cooling water intake structures. The regulations affect existing electricity generation facilities using over 50 million gallons per day, typically including some form of "once-through" cooling. The Utility’s Diablo Canyon power plant is among an estimated 539 generation facilities nationwide that are affected by this rulemaking. The Utility permanently closed its Hunters Point Power Plant in May 2006 and the Humboldt Bay Power Plant will be re-powered without the use of once-through cooling. The EPA regulations establish a set of performance standards that vary with the type of water body and that are intended to reduce impacts to aquatic organisms. Significant capital investment may be required to achieve the standards. The regulations allow site-specific compliance determinations if a facility’s cost of compliance is significantly greater than either the benefits achieved or the compliance costs considered by the EPA and also allow the use of environmental mitigation or restoration to meet compliance requirements in

certain cases. Various parties challenged the EPA's regulations, and the cases were consolidated in U.S. Court of Appeals for the Second Circuit, or Second Circuit.

On January 25, 2007, the Second Circuit issued its decision on the appeals of the EPA Section 316(b) regulations. The Second Circuit remanded significant provisions of the regulations to EPA for reconsideration and held that a cost benefit test cannot be used to establish performance standards or to grant variances form the standards. The Second Circuit also ruled that environmental restoration cannot be used to achieve compliance. The parties may seek either en banc review by the Second Circuit or review by the U.S. Supreme Court. Regardless of whether the decision is subject to further judicial review, the EPA will likely require significant time to review and revise the regulations. It is uncertain how the Second Circuit decision will affect development of the state's proposed implementation policy. The regulatory uncertainty is likely to continue and the Utility's cost of compliance, while likely to be significant, will remain uncertain as well.

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 $74 million at December 31, 2006 and approximately $388 million at December 31, 2005.

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

Chromium Litigation

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

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

PG&E Corporation and the Utility do not expect that the outcome with respect to the remaining unresolved claims will have a material adverse effect on their financial condition or results of operations.

Delayed Billing Investigation

In February 2005, the CPUC issued a ruling opening an investigation into the Utility's billing and collection practices and credit policies. The investigation was initiated at the request of The Utility Reform Network, or TURN, after the CPUC's January 2005 decision that characterized the definition of "billing error" in a revised Utility tariff to include delayed bills and Utility-caused estimated bills as being consistent with "existing CPUC policy, tariffs and requirements." The Utility contended that prior to the CPUC's January 2005 decision, "billing error" under the Utility's former tariffs did not encompass delayed bills or Utility-caused estimated bills. The Utility petitioned the California Court of Appeals to review the CPUC's decision denying rehearing of its January 2005 decision. In December 2006, the Court of Appeals summarily rejected the Utility's petition; the Utility did not appeal that rejection to the California Supreme Court.

The CPUC's Consumer Protection and Safety Division, or CPSD, and TURN have submitted their reports to the CPUC concluding that the Utility violated applicable tariffs related to delayed and estimated bills and recommended refunds in the current

amounts of approximately $54 million and $36 million, respectively, plus interest at the three-month commercial paper interest rate . The two refunds are not additive. The CPSD also recommended that the Utility pay fines of $6.75 million, while TURN recommends fines in the form of a $1 million contribution to REACH (Relief for Energy Assistance through Community Help). Both the CPSD and TURN recommend that refunds and fines be funded by shareholders.

The Utility responded that its tariff interpretation was in good faith, and was repeatedly supported by Commission staff. It argued that the CPUC should exercise its discretion not to order refunds, and that any ordered refunds should be treated in accordance with adopted ratemaking, under which the significant majority of the costs of any refunds would be reflected in future rates borne by the Utility's general body of customers. It argued that its behavior does not warrant fines or penalties. On February 15, 2007, the CPUC extended the date by which it must issue a final decision in this investigative matter to August 26, 2007.

On February 20, 2007, the administrative law judge presiding over the proceeding issued a "presiding officer" decision. Although the decision found that penalties were not warranted, the decision orders the Utility to refund, at shareholder expense, approximately $23 million to customers for "illegal backbill charges" relating to estimated and delayed bills that were charged to customers in excess of the time limits in the Utility's tariff. The decision also orders the Utility to refund reconnection fees and "pay credits to certain customers whose service was shutoff for nonpayment of illegal backbills."

Under CPUC rules, parties in an adjudicatory proceeding may appeal the presiding officer's decision within 30 days. In addition, any Commissioner may request review of the presiding officer's decision within 30 days of the date of issuance. If no appeal or request for review is filed within 30 days, the presiding officer's decision will become the final CPUC decision. The Utility intends to appeal the presiding officer's decision.

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

QUARTERLY CONSOLIDATED FINANCIAL DATA (UNAUDITED)

(in millions, except per share amounts)	Quarter ended December 31	September 30	June 30	March 31
2006				
PG&E CORPORATION				
Operating revenues	$ 3,206	$ 3,168	$ 3,017	$ 3,148
Operating income	439	735	465	469
Income from continuing operations	152	393	232	214
Net income	152	393	232	214
Earnings per common share from continuing operations, basic	0.43	1.09	0.65	0.61
Earnings per common share from continuing operations, diluted	0.43	1.09	0.65	0.60
Net income per common share, basic	0.43	1.09	0.65	0.61
Net income per common share, diluted	0.43	1.09	0.65	0.60
Common stock price per share:				
High	48.17	42.51	40.90	40.68
Low	40.72	39.06	38.30	36.25
UTILITY				
Operating revenues	$ 3,206	$ 3,168	$ 3,017	$ 3,148
Operating income	443	737	465	470
Net income	159	378	231	217
Income available for common stock	155	375	227	214
2005 [(1)]				
PG&E CORPORATION				
Operating revenues	$ 3,732	$ 2,804	$ 2,498	$ 2,669
Operating income	414	515	540	501
Income from continuing operations	180	239	267	218
Net income	180	252	267	218
Earnings per common share from continuing operations, basic	0.49	0.63	0.70	0.55
Earnings per common share from continuing operations, diluted	0.49	0.62	0.70	0.54
Net income per common share, basic	0.49	0.66	0.70	0.55
Net income per common share, diluted	0.49	0.65	0.70	0.54
Common stock price per share:				
High	40.10	39.64	37.91	36.18
Low	34.54	35.60	33.78	31.83
UTILITY				
Operating revenues	$ 3,733	$ 2,804	$ 2,498	$ 2,669
Operating income	418	517	540	495
Net income	187	248	276	223
Income available for common stock	183	244	272	219

[(1)] During the third quarter of 2005, PG&E Corporation received additional information from NEGT regarding income to be included in PG&E Corporation's 2004 federal income tax return. This information was incorporated in the 2004 tax return, which was filed with the IRS in September 2005. As a result, the 2004 federal income tax liability was reduced by approximately $19 million. In addition, NEGT provided additional information with respect to amounts previously included in PG&E Corporation's 2003 federal income tax return. This change resulted in PG&E Corporation's 2003 federal income tax liability increasing by approximately $6 million. These two adjustments, netting to $13 million, were recognized in income from discontinued operations in the third quarter of 2005.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of PG&E Corporation and Pacific Gas and Electric Company, or the Utility, is responsible for establishing and maintaining adequate internal control over financial reporting. PG&E Corporation's and the Utility's internal control over financial reporting is a process designed 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, or GAAP. Internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of PG&E Corporation and the Utility, (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP and that receipts and expenditures are being made only in accordance with authorizations of management and directors of PG&E Corporation and the Utility, and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its assessment and those criteria, management has concluded that PG&E Corporation and the Utility maintained effective internal control over financial reporting as of December 31, 2006.

Deloitte & Touche LLP, an independent registered public accounting firm, has audited the Consolidated Financial Statements of PG&E Corporation and the Utility for the three years ended December 31, 2006, appearing in this annual report and has issued an attestation report on management's assessment of internal control over financial reporting, as stated in their report, which is included in this annual report on page 118.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Boards of Directors and Shareholders of
PG&E Corporation and Pacific Gas and Electric Company

We have audited the accompanying consolidated balance sheets of PG&E Corporation and subsidiaries (the "Company") and of Pacific Gas and Electric Company and subsidiaries (the "Utility") as of December 31, 2006 and 2005, and the related consolidated statements of income, cash flows and shareholders' equity of the Company and of the Utility for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the respective managements of the Company and of the Utility. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the respective consolidated financial position of the Company and of the Utility as of December 31, 2006 and 2005, and the respective results of their consolidated operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 of the Notes to the Consolidated Financial Statements, in 2006 the Company and the Utility adopted new accounting standards for defined benefit pensions and other postretirement plans and share-based payments. In December 2005, the Company and the Utility adopted a new interpretation of accounting standards for asset retirement obligations. During March 2004, the Company changed the method of computing earnings per share.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's and the Utility's internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 21, 2007 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

DELOITTE & TOUCHE LLP

San Francisco, California
February 21, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Boards of Directors and Shareholders of
PG&E Corporation and Pacific Gas and Electric Company

We have audited management's assessment, included in the accompanying *Management's Report on Internal Control Over Financial Reporting* , that PG&E Corporation and subsidiaries (the "Company") and Pacific Gas and Electric Company and subsidiaries (the "Utility") maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's and the Utility's management is responsible for maintaining effective internal control over financial reporting and for their assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's and the Utility's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audits included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management and other personnel 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. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company and the Utility maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company and the Utility maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2006 of the Company and the Utility and our report dated February 21, 2007 expressed an unqualified opinion on those financial statements and financial statement schedules and included an explanatory paragraph relating to accounting changes.

DELOITTE & TOUCHE LLP

San Francisco, California
February 21, 2007

Exhibit 21

Subsidiaries

Parent of Subsidiary	Name of Subsidiary	Jurisdiction of Formation of Subsidiary	Names under which Subsidiary does business
PG&E Corporation	Pacific Gas and Electric Company	CA	Pacific Gas and Electric Company PG&E
Pacific Gas and Electric Company	PG&E Energy Recovery Funding LLC	DE	PG&E Energy Recovery Funding LLC

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statements No. 333-121518 on Form S-3 and 333-16253, 333-117930, 333-46772, 333-77149, 333-73054, and 333-129422 on Form S-8 of PG&E Corporation and Registration Statements No. 33-62488 and 333-109994 on Form S-3 of Pacific Gas and Electric Company of our reports dated February 21, 2007, relating to the financial statements and financial statement schedules of PG&E Corporation and Pacific Gas and Electric Company and management's report on the effectiveness of internal control over financial reporting, appearing in and incorporated by reference in this Annual Report on Form 10-K of PG&E Corporation and Pacific Gas and Electric Company for the year ended December 31, 2006.

DELOITTE & TOUCHE LLP

San Francisco, California
February 21, 2007

Exhibit 24.1

RESOLUTION OF THE
BOARD OF DIRECTORS OF
PG&E CORPORATION

February 21, 2007

WHEREAS, the Audit Committee of this Board of Directors has reviewed the audited consolidated financial statements for this corporation for the year ended December 31, 2006, and has recommended to the Board that such financial statements be included in the corporation's Annual Report on Form 10-K for the year ended December 31, 2006, to be filed with the Securities and Exchange Commission;

BE IT RESOLVED that each of HYUN PARK, LINDA Y.H. CHENG, EILEEN O. CHAN, WONDY S. LEE, ERIC MONTIZAMBERT, GARY P. ENCINAS, and KATHLEEN HAYES is hereby authorized to sign on behalf of this corporation and as attorneys in fact for the Chairman, Chief Executive Officer, and President, the Senior Vice President, Chief Financial Officer, and Treasurer, and the Vice President and Controller of this corporation the Form 10-K Annual Report for the year ended December 31, 2006, required by Section 13 or 15 (d) of the Securities Exchange Act of 1934 and all amendments and other filings or documents related thereto to be filed with the Securities and Exchange Commission, and to do any and all acts necessary to satisfy the requirements of the Securities Exchange Act of 1934 and the regulations of the Securities and Exchange Commission adopted thereunder with regard to said Form 10-K Annual Report.

I, LINDA Y.H. CHENG, do hereby certify that I am Vice President, Corporate Governance and Corporate Secretary of PG&E Corporation, a corporation organized and existing under the laws of the State of California; that the above and foregoing is a full, true, and correct copy of a resolution which was duly adopted by the Board of Directors of said corporation at a meeting of said Board which was duly and regularly called and held on February 21, 2007; and that this resolution has never been amended, revoked, or repealed, but is still in full force and effect.

WITNESS my hand and the seal of said corporation hereunto affixed this 21st day of February, 2007.

LINDA Y.H. CHENG

Linda Y.H. Cheng
Vice President, Corporate Governance and Corporate Secretary
PG&E Corporation

C O R P O R A T E

S E A L

RESOLUTION OF THE
BOARD OF DIRECTORS OF
PACIFIC GAS AND ELECTRIC COMPANY

February 21, 2007

WHEREAS, the Audit Committee of this Board of Directors has reviewed the audited consolidated financial statements for this company for the year ended December 31, 2006, and has recommended to the Board that such financial statements be included in the company's Annual Report on Form 10-K for the year ended December 31, 2006, to be filed with the Securities and Exchange Commission;

BE IT RESOLVED that each of HYUN PARK, LINDA Y.H. CHENG, EILEEN O. CHAN, WONDY S. LEE, ERIC MONTIZAMBERT, GARY P. ENCINAS, and KATHLEEN HAYES is hereby authorized to sign on behalf of this company and as attorneys in fact for the President and Chief Executive Officer, the Senior Vice President, Chief Financial Officer, and Treasurer, and the Vice President and Controller of this company the Form 10-K Annual Report for the year ended December 31, 2006, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and all amendments and other filings or documents related thereto to be filed with the Securities and Exchange Commission, and to do any and all acts necessary to satisfy the requirements of the Securities Exchange Act of 1934 and the regulations of the Securities and Exchange Commission adopted thereunder with regard to said Form 10-K Annual Report.

I, LINDA Y.H. CHENG, do hereby certify that I am Vice President, Corporate Governance and Corporate Secretary of PACIFIC GAS AND ELECTRIC COMPANY, a corporation organized and existing under the laws of the State of California; that the above and foregoing is a full, true, and correct copy of a resolution which was duly adopted by the Board of Directors of said corporation at a meeting of said Board which was duly and regularly called and held on February 21, 2007; and that this resolution has never been amended, revoked, or repealed, but is still in full force and effect.

WITNESS my hand and the seal of said corporation hereunto affixed this 21st day of February, 2007.

LINDA Y.H. CHENG

Linda Y.H. Cheng
Vice President, Corporate Governance and Corporate Secretary
PG&E Corporation

C O R P O R A T E

S E A L

Exhibit 24.2

POWER OF ATTORNEY

Each of the undersigned Directors of PG&E Corporation hereby constitutes and appoints HYUN PARK, LINDA Y.H. CHENG, EILEEN O. CHAN, WONDY S. LEE, ERIC MONTIZAMBERT, GARY P. ENCINAS, and KATHLEEN HAYES, and each of them, as his or her attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his or her capacity as such Director of said corporation the Form 10-K Annual Report for the year ended December 31, 2006, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, we have signed these presents this 21st day of February, 2007.

DAVID R. ANDREWS
David R. Andrews

MARYELLEN C. HERRINGER
Maryellen C. Herringer

LESLIE S. BILLER
Leslie S. Biller

RICHARD A. MESERVE
Richard A. Meserve

DAVID A. COULTER
David A. Coulter

MARY S. METZ
Mary S. Metz

C. LEE COX
C. Lee Cox

BARBARA L. RAMBO
Barbara L. Rambo

PETER A. DARBEE
Peter A. Darbee

BARRY LAWSON WILLIAMS
Barry Lawson Williams

POWER OF ATTORNEY

PETER A. DARBEE, the undersigned, Chairman of the Board, Chief Executive Officer, and President of PG&E Corporation, hereby constitutes and appoints HYUN PARK, LINDA Y.H. CHENG, EILEEN O. CHAN, WONDY S. LEE, ERIC MONTIZAMBERT, GARY P. ENCINAS, and KATHLEEN HAYES, and each of them, as his attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his capacity as Chairman of the Board, Chief Executive Officer, and President (principal executive officer) of said corporation the Form 10-K Annual Report for the year ended December 31, 2006, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, I have signed these presents this 21st day of February, 2007.

PETER A. DARBEE

Peter A. Darbee

POWER OF ATTORNEY

CHRISTOPHER P. JOHNS, the undersigned, Senior Vice President, Chief Financial Officer, and Treasurer of PG&E Corporation, hereby constitutes and appoints HYUN PARK, LINDA Y.H. CHENG, EILEEN O. CHAN, WONDY S. LEE, ERIC MONTIZAMBERT, GARY P. ENCINAS, and KATHLEEN HAYES, and each of them, as his attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his capacity as Senior Vice President, Chief Financial Officer, and Treasurer (principal financial officer) of said corporation the Form 10-K Annual Report for the year ended December 31, 2006, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, I have signed these presents this 21st day of February, 2007.

CHRISTOPHER P. JOHNS

Christopher P. Johns

POWER OF ATTORNEY

G. ROBERT POWELL, the undersigned, Vice President and Controller of PG&E Corporation, hereby constitutes and appoints HYUN PARK, LINDA Y.H. CHENG, EILEEN O. CHAN, WONDY S. LEE, ERIC MONTIZAMBERT, GARY P. ENCINAS, and KATHLEEN HAYES, and each of them, as his attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his capacity as Vice President and Controller (principal accounting officer) of said corporation the Form 10-K Annual Report for the year ended December 31, 2006, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, I have signed these presents this 21st day of February, 2007.

G. ROBERT POWELL

G. Robert Powell

POWER OF ATTORNEY

Each of the undersigned Directors of Pacific Gas and Electric Company hereby constitutes and appoints HYUN PARK, LINDA Y.H. CHENG, EILEEN O. CHAN, WONDY S. LEE, ERIC MONTIZAMBERT, GARY P. ENCINAS, and KATHLEEN HAYES, and each of them, as his or her attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his or her capacity as such Director of said corporation the Form 10-K Annual Report for the year ended December 31, 2006, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, we have signed these presents this 21st day of February, 2007.

DAVID R. ANDREWS
David R. Andrews

LESLIE S. BILLER
Leslie S. Biller

DAVID A. COULTER
David A. Coulter

C. LEE COX
C. Lee Cox

PETER A. DARBEE
Peter A. Darbee

MARYELLEN C. HERRINGER
Maryellen C. Herringer

THOMAS B. KING
Thomas B. King

RICHARD A. MESERVE
Richard A. Meserve

MARY S. METZ
Mary S. Metz

BARBARA L. RAMBO
Barbara L. Rambo

BARRY LAWSON WILLIAMS
Barry Lawson Williams

POWER OF ATTORNEY

THOMAS B. KING, the undersigned, Chief Executive Officer of Pacific Gas and Electric Company, hereby constitutes and appoints HYUN PARK, LINDA Y.H. CHENG, EILEEN O. CHAN, WONDY S. LEE, ERIC MONTIZAMBERT, GARY P. ENCINAS, and KATHLEEN HAYES, and each of them, as his attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his capacity Chief Executive Officer (principal executive officer) of said corporation the Form 10-K Annual Report for the year ended December 31, 2006, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, I have signed these presents this 21st day of February, 2007.

THOMAS B. KING

Thomas B. King

POWER OF ATTORNEY

CHRISTOPHER P. JOHNS, the undersigned, Senior Vice President, Chief Financial Officer, and Treasurer of Pacific Gas and Electric Company, hereby constitutes and appoints HYUN PARK, LINDA Y.H. CHENG, EILEEN O. CHAN, WONDY S. LEE, ERIC MONTIZAMBERT, GARY P. ENCINAS, and KATHLEEN HAYES, and each of them, as his attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his capacity as Senior Vice President, Chief Financial Officer, and Treasurer (principal financial officer) of said corporation the Form 10-K Annual Report for the year ended December 31, 2006, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, I have signed these presents this 21st day of February, 2007.

CHRISTOPHER P. JOHNS

Christopher P. Johns

POWER OF ATTORNEY

G. ROBERT POWELL, the undersigned, Vice President and Controller of Pacific Gas and Electric Company, hereby constitutes and appoints HYUN PARK, LINDA Y.H. CHENG, EILEEN O. CHAN, WONDY S. LEE, ERIC MONTIZAMBERT, GARY P. ENCINAS, and KATHLEEN HAYES, and each of them, as his attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his capacity as Vice President and Controller (principal accounting officer) of said corporation the Form 10-K Annual Report for the year ended December 31, 2006, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, I have signed these presents this 21st day of February, 2007.

G. ROBERT POWELL

G. Robert Powell

Exhibit 31.1

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

I, Peter A. Darbee, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2006 of PG&E Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 22, 2007

PETER A. DARBEE
Peter A. Darbee
Chairman, Chief Executive Officer and President

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

I, Christopher P. Johns, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2006 of PG&E Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 22, 2007

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

Exhibit 31.2

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

I, Thomas B. King, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2006 of Pacific Gas and Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 22, 2007

THOMAS B. KING
Thomas B. King
Chief Executive Officer

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

I, Christopher P. Johns, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2006 of Pacific Gas and Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 22, 2007

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

Exhibit 32.1

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

In connection with the accompanying Annual Report on Form 10-K of PG&E Corporation for the year ended December 31, 2006, I, Peter A. Darbee, Chairman, Chief Executive Officer and President of PG&E Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) such Annual Report on Form 10-K of PG&E Corporation for the year ended December 31, 2006, fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Annual Report on Form 10-K of PG&E Corporation for the year ended December 31, 2006, fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

PETER A. DARBEE

PETER A. DARBEE.
Chairman, Chief Executive Officer and President

February 22, 2007

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

In connection with the accompanying Annual Report on Form 10-K of PG&E Corporation for the year ended December 31, 2005, I, Christopher P. Johns, Senior Vice President, Chief Financial Officer and Treasurer of PG&E Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) such Annual Report on Form 10-K of PG&E Corporation for the year ended December 31, 2006, fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Annual Report on Form 10-K of PG&E Corporation for the year ended December 31, 2006, fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

CHRISTOPHER P. JOHNS

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

February 22, 2007

Exhibit 32.2

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

In connection with the accompanying Annual Report on Form 10-K of Pacific Gas and Electric Company for the year ended December 31, 2006, I, Thomas B. King, 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 Annual Report on Form 10-K of Pacific Gas and Electric Company for the year ended December 31, 2006, fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Annual Report on Form 10-K of Pacific Gas and Electric Company for the year ended December 31, 2006, fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

THOMAS B. KING

THOMAS B. KING
Chief Executive Officer

February 22, 2007

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

In connection with the accompanying Annual Report on Form 10-K of Pacific Gas and Electric Company for the year ended December 31, 2006, I, Christopher P. Johns, Senior Vice President, Chief Financial Officer and Treasurer of Pacific Gas and Electric Company, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) such Annual Report on Form 10-K of Pacific Gas and Electric Company for the year ended December 31, 2006, fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in such Annual Report on Form 10-K of Pacific Gas and Electric Company for the year ended December 31, 2006, fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

CHRISTOPHER P. JOHNS

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

February 22, 2007