PG&E Corporation and Pacific Gas and Electric Company
2009 ANNUAL REPORT

TABLE OF CONTENTS

A LETTER TO OUR STAKEHOLDERS

Five years ago, we set a new course for PG&E, energized by an ambitious vision, a renewed focus on values, and a smart and simple strategy. This fusion of vision, values, and strategy has been the force behind half a decade of dynamism and growth. And it remains as durable and relevant today as when we first embraced it.

PG&E's journey over the past five years has been a remarkable one. Emerging from the turmoil and stigma of the state's energy crisis–the lowest time in the company's history–we revitalized PG&E's relationships with our customers and communities, revamped our operations, and reclaimed our identity as a standard-bearer for innovation, collaboration, and progress. Along the way, we rediscovered the best things about our people and our culture. At the same time, we openly embraced the need for new ways of working and thinking about the future of our business.

Invigorated by this renewal, PG&E has risen to become one of the industry's leading performers in recent years. Our results for customers and shareholders in 2009 built on this track record once again.

Among our accomplishments were new enhancements to our infrastructure, major improvements in safety and reliability, further deployment of smart grid technology, new commitments to increase renewable energy supplies, and significant energy savings through our customer energy efficiency programs.

These and other achievements helped us increase overall customer satisfaction while also providing a competitive total return to investors.

Today, looking at 2010 and beyond, our task is to sustain PG&E's strong momentum–and to ensure we are doing so in ways that are in step with and responsive to shifts and challenges in the economy.

More than any other single factor last year, the business environment was marked by concern over the recession's implications for our customers and communities, which have been hit with some of America's worst job-loss and home-foreclosure rates.

In response, PG&E has stepped up outreach and provided financial assistance to large numbers of customers through a wide assortment of programs. Across the hundreds of communities we serve, we also increased the support we provide through shareholder-funded charitable contributions. Last year's total giving was our highest ever, consistent with our belief that PG&E's special privilege as a utility comes with a unique duty to give back.

Equally critical, we followed through on commitments to maintain a steady flow of capital investments. This meant that many local suppliers, contractors, and subcontractors who count on PG&E as a mainstay of their business were able to keep doing so. This has been all the more important in light of decisions by many other companies to throttle back on new investments and spending.

Moving forward, one of the biggest roles we expect to play for customers and communities is to serve as an even greater force for economic revival and growth.

The investments we are making today in California's infrastructure–and those we are seeking permission to make in the next few years–support new and existing jobs and put money back into local economies at a moment when private sector investment is so vital.

But even more important is the broader economic promise that smart energy investments hold.

Many experts believe that a 21st-century energy economy will be the backbone for America's growth and competitiveness in the decades ahead. We agree. The clean, highly efficient, and highly reliable energy infrastructure we are working to build is fundamental to this future.

For these reasons, the downturn has made the job of modernizing California's energy economy more pressing, not less. We believe that state leaders understand this and will support efforts that strike the right balance between the pragmatism that immediate challenges dictate and the continuing investment necessary to ensure a stable, vibrant economic climate.

For our part, we intend to stay true to the same vision, values, and strategy that have delivered for customers and shareholders in recent years. In 2010, we are focused again on knowing and responding to the unique needs of our different customers, running our operations with excellence, working constructively with policymakers and regulators, demonstrating environmental leadership, and staying connected with our communities.

This letter outlines examples of the ways we are putting this strategy into action, the results it is making possible, and the outlook for the current year and beyond.

PROVIDING VALUE FOR INVESTORS

Ensuring that PG&E Corporation represents a solid value for investors is an essential prerequisite for our success. Utilities that are financially sound and healthy have the wherewithal to attract new capital at reasonable costs and fund smart long-term investments for customers.

Last year's financial results showed that we continue to provide the kinds of opportunities that investors are seeking. We grew core earnings primarily through a combination of new capital investments in PG&E's utility asset base, along with incentives earned by helping customers realize aggressive energy efficiency targets and efficiencies realized by effectively managing our resources.

Total net income for 2009 was solid at $1.22 billion, or $3.20 per share, as reported under generally accepted accounting principles (GAAP). This compared with net income of $1.34 billion for 2008, which was enlarged significantly by the one-time benefits of a multiyear tax settlement.

Earnings per share from operations, a non-GAAP measure adjusted to reflect normal operations and exclude unusual items like last year's tax settlement, were $3.21 per share, up almost 9 percent over 2008 levels. (The "Financial Highlights" table on page 7 reconciles GAAP total net income with non-GAAP earnings from operations.)

These results were just above the midpoint of our earnings guidance range, and they exceeded Wall Street's consensus expectation.

In addition to earnings growth, in early 2009 we raised PG&E Corporation's common stock dividend. The 8 percent increase was in keeping with our view that dividend growth should accompany growth in earnings over time. In fact, we raised the dividend again in early 2010 on the strength of our full-year 2009 results and our confidence in the outlook for 2010.

Total shareholder return for 2009—stock price appreciation plus dividends—was 20 percent. As strong as PG&E's return was, however, it put us in the middle of the pack last year relative to comparable utilities, many of which were rebounding from the dramatic decline in late 2008.

But if some of our peers bounced back more strongly, it is also the case that in many instances their shares had fallen further. As we noted last year, PG&E shares held their value better than many other utilities during the downturn.

A truer indication of PG&E's relative strength is the company's two- and three-year total shareholder returns. Over the past three years, our return put the company firmly in the top half of the peers we track. And over the past two years, our return has been the best in the group.

More importantly, our financial forecasts for 2010 and 2011 reflect expectations that earnings will keep growing at a competitive pace. Indeed, our goal is to deliver total shareholder returns that are in the top 25 percent among comparable utilities.

INVESTING IN CALIFORNIA'S ENERGY FUTURE

Last year's capital investment once again focused principally on increasing reliability and capacity across the extensive network of wires, pipes, generating stations, and other essential assets at the heart of California's energy infrastructure.

PG&E's total capital expenditures in 2009 were $3.9 billion. This exceeded our initial capital spending goals for the year, but remained consistent with our projected range for annual average capital expenditures over the 2008 through 2011 time frame.

The majority of these resources supported ongoing efforts to strengthen local electric and natural gas distribution systems. For example, we made improvements to a number of our least reliable electric circuits, we added new protective equipment to lines, and we installed new hardware to enhance power restoration capabilities in certain reliability hot spots.

We also proceeded with efforts to lay the foundation for the emerging smart grid, through the ongoing transition to SmartMeter™ technology. By year's end, total installations of new gas and electric meters reached approximately 4.5 million out of a total of 10 million that will be in place by mid-2012.

With its ability to send timely energy-usage data and its Web-like connectivity options, SmartMeter™ technology will be the basis for a range of new energy management tools and capabilities, which are key to improving customer service, increasing reliability, expanding energy efficiency and demand response, and optimizing the use of renewable energy sources and, soon, electric vehicles.

Last year also saw further heavy investment in electric transmission, with a focus on asset replacement and alleviating grid congestion. Other projects in this area were aimed at interconnecting new generation, including new renewable power sources, and improving reliability through automation.

PG&E also won federal support for a project to install new monitoring and communications technology within our electric transmission system. Known as synchrophasors, the devices will help identify and address potential reliability concerns and improve our ability to integrate intermittent renewable power resources.

Within our power generation operations, we forged ahead with both conventional and renewable generating projects.

PG&E's Gateway Generating Station went into service in early 2009, ahead of schedule, within budget, and with an exceptional safety record in construction—all of which set the stage for an exceptionally safe and reliable first year of operations. A showcase for the latest in clean, highly efficient gas-fired generation, the plant earned project-of-the-year accolades from *Power Engineering* magazine. Construction also progressed on two other conventional-fueled facilities, Humboldt Bay and Colusa Generating Station. Humboldt Bay is expected to be completed in the third quarter of 2010, and Colusa Generating Station is expected to be completed several months later.

Importantly, we also unveiled PG&E's first plans to own new renewable generation assets. These include a proposed project to build 250 megawatts of PG&E-owned solar photovoltaic resources (in addition to another 250 megawatts that would be owned by other developers). We also proposed to buy and operate a major wind energy facility. If approved and built, it would provide enough power for about 100,000 average homes. Both the solar and wind projects are awaiting regulatory approval.

Within our existing fleet, we completed major capital projects to help ensure the ongoing safe and reliable operation of the Diablo Canyon Power Plant, a critical source of carbon-free nuclear power for millions of Californians. We also began the multiyear regulatory process to renew the licenses for this essential facility so that it will be available to provide power well into this century.

OPERATING WITH EXCELLENCE

Even with the right investments in our system, delivering for customers ultimately depends on our people and practices. As a result, operational excellence—safety, reliability, productivity, and on-budget and on-time performance—is central to our strategy.

Last year's operational metrics show that PG&E's intensive efforts in these areas are paying off.

Nowhere is this more true than on our number one priority, safety. In 2009, the three basic safety indicators we monitor all continued to move decisively in the right direction.

Thanks to improved training, improved work procedures, and an emphasis on accountability, we achieved major reductions in recordable injuries, lost workdays, and motor vehicle incidents.

We exceeded our goals in all three categories. Most extraordinarily, since 2006, we have bettered performance in each of these areas by more than 50 percent.

However, notwithstanding these achievements, our safety results are not yet where they must be. On-the-job tragedies took the lives of two workers last year, and our overall safety scores still trail those of the top performers in the industry.

Our pledge is that reducing safety incidents will remain a top priority until we reach the absolute goal of zero injuries.

Importantly, while this commitment is about people first, it is also about performance: A safer workplace is a more productive, efficient, cost-effective workplace. In fact, excellence in safety is one of the best bellwethers of overall operational excellence.

Another key benchmark of excellence is reliability. In fact, our customers consistently rank reliability as a top driver for satisfaction.

In 2009, through a combination of strategic investments, more rigorous and efficient work practices, and excellent teamwork, we dramatically drove down both the frequency and duration of electric outages, our two key reliability measures.

Although our targets set a high bar for the year, our teams exceeded the goals on both measures. PG&E customers experienced service interruptions less often than at any time in the last 22 years. And if they did, we restored their service faster than at any time in the past nine years.

We also focused again on the reliability of our natural gas operations. Last year's accomplishments included completing 1.9 million on-location service line inspections as part of an ongoing initiative to survey the integrity of our entire gas distribution network on an accelerated basis. This progress exceeded our target for the year.

Other operational highpoints included more progress in streamlining processes and making it easier for our employees to serve customers; solid storm recovery efforts; excellent execution on the steam generator, dry cask storage, and reactor-head replacement projects at Diablo Canyon; and the remarkably safe and smooth construction of the Humboldt and Colusa generating projects.

TAKING CARE OF CUSTOMERS

Our principal barometer for measuring customer satisfaction—a series of independent surveys that look at customers' views on reliability, pricing, service interactions, and overall favorability—rose in 2009 compared with 2008, exceeding our target.

We view last year's positive feedback as a considerable accomplishment in light of the strain that the tough economy has placed on some customers. We attribute this to the marked improvements in electric reliability and our outreach to customers who were struggling to stay current with their bills.

As noted earlier, we significantly ramped up efforts to inform customers about various ways PG&E can lend a hand to those who need it. Our Breathe Easy Solutions™ initiative raised broad customer awareness of a full range of options, from direct financial assistance to flexible payment plans and help through energy efficiency programs.

Among the most telling signs of success was the increased enrollment in PG&E's CARE Program, which assists income-qualified customers through discounts on their monthly energy bills. The program added more than 466,000 new participants in 2009.

Higher program enrollment numbers were also a validation of our efforts to know our customers better than ever before. More than ever, we are making smart use of our knowledge of customers' specific needs and preferences to tailor our service offerings and effectively match customers with the right products and programs. This will remain a key pillar of our strategy going forward.

FOCUSING ON SUSTAINABILITY

Of all the influences reshaping our business–the advent of smart technologies, the tough economy, the need to replace aging infrastructure, and rising customer expectations–the most fundamental is the need to produce and use energy in ways that are cleaner and more efficient. Climate change, water scarcity, waste reduction, air and water quality, habitat protection, and other sustainability issues are compelling utilities to take a fresh look at their end-to-end operations and assess basic policies and priorities.

Last year, we continued to answer this challenge in different ways, from reducing water and energy consumption in our facilities to offsetting the carbon emissions associated with the energy we use in our offices and maintenance facilities.

One of the most important ways was helping customers through our industry-leading energy efficiency initiatives.

In 2009, we again enabled customers to achieve extraordinary energy savings. We expect that when the final analysis of last year's programs is complete, it will confirm that we surpassed the gas and electric savings goals that the state set for the year.

We also received $33.4 million in energy efficiency incentives last year, earned in return for helping customers achieve savings in the 2006-2008 program cycle.

Energy efficiency remains the most readily available, cost-effective, and powerful resource to meet new demand, produce energy savings, and reduce emissions in the near term. In fact, in the decade ahead, PG&E plans to meet almost half of customers' new energy demand through energy efficiency.

In addition to helping customers save energy, we continued to provide them with an energy supply that is among the cleanest in the nation. PG&E's carbon dioxide emissions rate is approximately 50 percent lower than that of the average utility.

Our supply will become even cleaner in the future. In 2009, we signed 42 new renewable energy purchase contracts. If all of these projects are built, these agreements will represent additions of more than 4,200 megawatts of new renewable resources to our future supply.

PG&E also successfully secured $25 million from the U.S. Department of Energy to fund preliminary work on a compressed-air energy storage project. The project will use night-time energy, when wind power is most abundant, to pump air underground. The air can then be released to drive turbines as needed, delivering 300 megawatts of power for up to 10 hours.

On the policy front, we continued to work with policymakers to advance federal climate and energy legislation that puts a price on carbon emissions. We believe strongly that well-crafted legislation to address greenhouse gas emissions can provide clarity that drives business investment in cleaner, more efficient technologies while also protecting consumers.

These and other examples of leadership on the environment have distinguished PG&E in the eyes of key observers. In 2009, PG&E was one of only two U.S. utility companies named to the prestigious Dow Jones Sustainability World Index, which lists the top 10 percent of companies worldwide that lead their industries in managing economic, environmental, and social issues.

ATTAINING OUR VISION

As we look forward, 2010 is set to be a demanding and pivotal year–demanding because of the goals we have set for ourselves and the difficulties that persist in the economy, and pivotal because the way we balance and resolve critical issues this year will in many ways set the stage for the next few years and the opportunities ahead.

Even so, our confidence in PG&E's vision, values, and strategy remains firm. We know the road ahead will hold challenges. But we also know that PG&E is well suited to succeed in this environment.

Our plans for additional investment in California's energy future are compelling and in harmony with the priorities of our customers and the state's leaders.

Our successful efforts to help customers last year are continuing in 2010, including efforts to ease rate pressures and ensure affordable service.

Our determination to keep raising the bar on safety and reliability is unyielding.

Our engagement with our communities remains high.

Our commitment to working constructively with regulators to produce win-win solutions for customers is as strong as ever.

Our leadership on clean energy and efficiency promises to enable us to capture more new opportunities in this area.

Above all, our people are among the most talented, dedicated, and innovative in the industry.

As a result, we look to the future with great optimism. Earlier this year, in fact, we reaffirmed our commitment to become the nation's leading utility–and we set a goal to do so by 2014. We are defining this objective now more clearly than we ever have before, with high bars set for customer satisfaction, employee engagement, environmental leadership, and shareholder return.

The many accomplishments of 2009 and the past five years give us a platform that now puts these goals within striking distance. You have our team's pledge that we will work relentlessly toward this vision in 2010 and over the next several years. We look forward to sharing our progress with all of our stakeholders.

Sincerely,

Peter A. Darbee
Chairman of the Board, Chief Executive Officer,
and President of PG&E Corporation

March 15, 2010

FINANCIAL STATEMENTS
TABLE OF CONTENTS

FINANCIAL HIGHLIGHTS
PG&E Corporation

(unaudited, in millions, except share and per share amounts)	**2009**	2008
Operating Revenues	**$ 13,399**	$ 14,628
Income Available for Common Shareholders		
Earnings from operations[(1)]	**1,223**	1,081
Items impacting comparability[(2)]	**(3)**	257
Reported consolidated income available for common shareholders	**1,220**	1,338
Income Per Common Share, diluted		
Earnings from operations[(1)]	**3.21**	2.95
Items impacting comparability[(2)]	**(0.01)**	0.68
Reported consolidated net earnings per common share, diluted	**3.20**	3.63
Dividends Declared Per Common Share	**1.68**	1.56
Total Assets at December 31,	**$ 42,945**	$ 40,860
Number of common shares outstanding at December 31,	**371,272,457**	362,346,685

(1) "Earnings from operations" is not calculated in accordance with the accounting principles generally accepted in the United States of America ("GAAP"). It should not be considered an alternative to income available for common shareholders calculated in accordance with GAAP. Earnings from operations reflects PG&E Corporation's consolidated income available for common shareholders, but excludes items that management believes do not reflect the normal course of operations, in order to provide a measure that allows investors to compare the core underlying financial performance of the business from one period to another.

(2) "Items impacting comparability" represent items that management believes do not reflect the normal course of operations. PG&E Corporation's earnings from operations for 2009 excludes the impact of the following items:

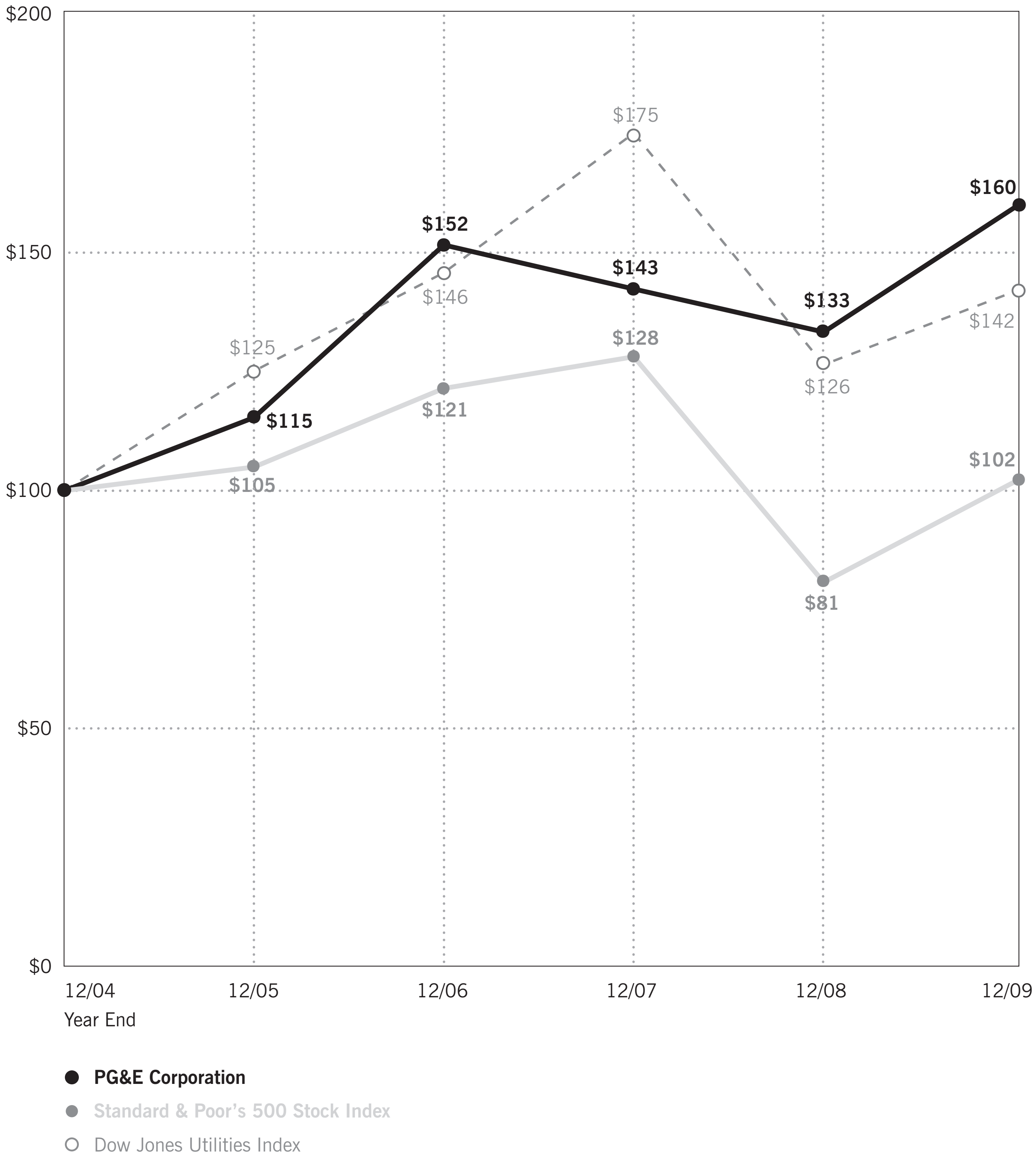
- $66 million of income, after tax, ($0.18 per common share) for the interest and state tax benefit associated with a federal tax refund for 1998 and 1999.
- $28 million of income, after tax, ($0.07 per common share) representing the recovery of costs previously incurred by PG&E Corporation's subsidiary, Pacific Gas and Electric Company ("Utility"), in connection with its hydroelectric generation facilities.
- $59 million of costs, after tax, (($0.16) per common share) incurred by the Utility to perform accelerated system-wide natural gas integrity surveys and associated remedial work.
- $38 million of severance costs, after-tax, (($0.10) per common share) related to the elimination of approximately 2% percent of the Utility's workforce.

PG&E Corporation's earnings from operations for 2008 exclude the impact of $257 million in net income ($0.68 per common share) resulting from a settlement of federal tax audits for the years 2001 through 2004.

PG&E Corporation common stock is traded on the New York Stock Exchange. The official New York Stock Exchange symbol for PG&E Corporation is "PCG."

COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL SHAREHOLDER RETURN (1)

This graph compares the cumulative total return on PG&E Corporation common stock (equal to dividends plus stock price appreciation) during the past five fiscal years with that of the Standard & Poor's 500 Stock Index and the Dow Jones Utilities Index.



(1) Assumes $100 invested on December 31, 2004, in PG&E Corporation common stock, the Standard & Poor's 500 Stock Index, and the Dow Jones Utilities Index, and assumes quarterly reinvestment of dividends. The total shareholder returns shown are not necessarily indicative of future returns.

SELECTED FINANCIAL DATA

(in millions, except per share amounts)	**2009**	2008	2007	2006	2005
PG&E Corporation(1)					
For the Year					
Operating revenues	**$13,399**	$14,628	$13,237	$12,539	$11,703
Operating income	**2,299**	2,261	2,114	2,108	1,970
Income from continuing operations	**1,234**	1,198	1,020	1,005	920
Earnings per common share from continuing operations, basic	**3.25**	3.23	2.79	2.78	2.37
Earnings per common share from continuing operations, diluted	**3.20**	3.22	2.78	2.76	2.34
Dividends declared per common share(2)	**1.68**	1.56	1.44	1.32	1.23
At Year-End					
Book value per common share(3)	**$ 26.68**	$ 24.64	$ 22.91	$ 21.24	$ 19.94
Common stock price per share	**44.65**	38.71	43.09	47.33	37.12
Total assets	**42,945**	40,860	36,632	34,803	34,074
Long-term debt (excluding current portion)	**10,381**	9,321	8,171	6,697	6,976
Rate reduction bonds (excluding current portion)	**–**	–	–	–	290
Energy recovery bonds (excluding current portion)	**827**	1,213	1,582	1,936	2,276
Noncontrolling interest – preferred stock of subsidiary	**252**	252	252	252	252
Pacific Gas and Electric Company					
For the Year					
Operating revenues	**$13,399**	$14,628	$13,238	$12,539	$11,704
Operating income	**2,302**	2,266	2,125	2,115	1,970
Income available for common stock	**1,236**	1,185	1,010	971	918
At Year-End					
Total assets	**42,709**	40,537	36,310	34,371	33,783
Long-term debt (excluding current portion)	**10,033**	9,041	7,891	6,697	6,696
Rate reduction bonds (excluding current portion)	**–**	–	–	–	290
Energy recovery bonds (excluding current portion)	**827**	1,213	1,582	1,936	2,276

(1) Matters relating to discontinued operations are discussed in the section entitled "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Note 9 of the Notes to the Consolidated Financial Statements.

(2) The Board of Directors of PG&E Corporation declared a cash dividend of $0.30 per quarter for the first three quarters of 2005. In the fourth quarter of 2005, the Board of Directors increased the quarterly cash dividend to $0.33 per share. Beginning in the first quarter of 2007, the Board of Directors increased the quarterly cash dividend to $0.36 per share. Beginning in the first quarter of 2008, the Board of Directors increased the quarterly cash dividend to $0.39 per share. Beginning in the first quarter of 2009, the Board of Directors increased the quarterly cash dividend to $0.42 per share. The Utility paid quarterly dividends on common stock held by PG&E Corporation of $624 million in 2009. The Utility paid quarterly dividends on common stock held by PG&E Corporation and a wholly owned subsidiary aggregating to $589 million in 2008 and $547 million in 2007. See Note 6 of the Notes to the Consolidated Financial Statements.

(3) Book value per common share includes the effect of participating securities. The dilutive effect of outstanding stock options and restricted stock is further disclosed in Note 8 of the Notes to the Consolidated Financial Statements.

OVERVIEW

PG&E Corporation, incorporated in California in 1995, is a holding company whose primary purpose is to hold interests in energy-based businesses. PG&E Corporation conducts its business principally through Pacific Gas and Electric Company ("Utility"), a public utility operating in northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. 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 electric distribution customers and approximately 4.3 million natural gas distribution customers at December 31, 2009. The Utility had $42.7 billion in assets at December 31, 2009 and generated revenues of $13.4 billion in the 12 months ended December 31, 2009.

The Utility is regulated primarily by the California Public Utilities Commission ("CPUC") and the Federal Energy Regulatory Commission ("FERC"). In addition, the Nuclear Regulatory Commission ("NRC") oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities. The CPUC has jurisdiction over the rates and terms and conditions of service for the Utility's electric and natural gas distribution operations, electric generation, and natural gas transportation and storage. The FERC has jurisdiction over the rates and terms and conditions of service governing the Utility's electric transmission operations and over the rates and terms and conditions of service governing the Utility on its interstate natural gas transportation contracts. Before setting rates, the CPUC and the FERC determine the annual amount of revenue ("revenue requirements") that the Utility is authorized to collect from its customers to recover its reasonable operating and capital costs of providing utility services. The authorized revenue requirements also provide the Utility an opportunity to earn a return on "rate base," the Utility's net investment in facilities, equipment, and other property used or useful in providing utility service to its customers. The CPUC requires the Utility to maintain a certain capital structure (i.e., the relative weightings of common equity, preferred equity, and debt) when financing its rate base and authorizes the Utility to earn a specific rate of return on each capital component.

The Utility's ability to recover the revenue requirements, authorized by the CPUC in the general rate case ("GRC"), does not depend on the volume of the Utility's sales of electricity and natural gas services. This "decoupling" of revenues and sales eliminates volatility in the revenues earned by the Utility due to fluctuations in customer demand. However, fluctuations in operating and maintenance costs may impact the Utility's ability to earn its authorized rate of return. Generally, the Utility's recovery of its FERC-authorized revenue requirements can vary with the volume of electricity sales. A portion of the Utility's CPUC-authorized revenue requirements for its natural gas transportation and storage services also depends on the volume of natural gas transported and the extent to which the Utility provides firm transmission services.

The Utility also collects additional revenue requirements to recover certain costs that the Utility has been authorized to pass on to customers, including costs to purchase electricity and natural gas; to fund public purpose, demand response, and customer energy efficiency programs; and to recover certain capital expenditures. The Utility's ability to recover these costs is not dependent on the volume of the Utility's sales. Therefore, although the timing and amount of these costs can impact the Utility's revenue, these costs generally do not impact earnings.

The Utility's revenues and earnings also are affected by incentive ratemaking mechanisms that adjust rates depending on the extent the Utility meets certain performance criteria.

The Utility uses regulatory balancing accounts primarily to accumulate differences between actual billed and unbilled revenues and the Utility's authorized revenue requirements for the period. The Utility also uses regulatory balancing accounts to accumulate differences between incurred costs and actual billed and unbilled revenues, as well as differences between incurred costs and authorized revenue meant to recover those costs. The CPUC periodically authorizes adjustments to electric and natural gas rates to (1) reflect over- and under-collections in the Utility's major electric and natural gas balancing accounts, and (2) implement various other electric and natural gas revenue requirement changes authorized by the CPUC and the FERC. Generally, these 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.

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 as well as the accounts of variable interest entities for which the Utility absorbs a majority of the risk of loss or gain. This combined Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") of PG&E Corporation and the Utility should be read in conjunction with the Consolidated Financial Statements and the Notes to the Consolidated Financial Statements included in this annual report.

SUMMARY OF CHANGES IN EARNINGS PER COMMON SHARE AND INCOME AVAILABLE FOR COMMON SHAREHOLDERS FOR 2009

PG&E Corporation's diluted earnings per common share ("EPS") for 2009 were $3.20 per share, compared to $3.63 per share for 2008. PG&E Corporation's 2009 income available for common shareholders decreased by $118 million, or 9%, to $1,220 million, compared to 2008 income available for common shareholders of $1,338 million. The decrease in diluted EPS and income available for common shareholders in 2009 as compared to 2008 is primarily due to (1) $257 million of net income recognized in 2008 resulting from a settlement of tax audits for 2001 through 2004, and (2) $59 million, after tax, attributable to costs to perform accelerated natural gas leak surveys and associated remedial work. These decreases were partially offset by (1) a $91 million, after tax, increase due to the Utility's return on equity ("ROE") earned on higher authorized capital investment, and (2) a tax benefit of $66 million associated with the settlement of tax refund claims involving the 1998 and 1999 tax years.

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, recover its authorized costs timely, and earn its authorized rate of return. A number of factors have had, or are expected to have, a significant impact on PG&E Corporation's and the Utility's results of operations and financial condition, including:

- **The Outcome of Regulatory Proceedings and the Impact of Ratemaking Mechanisms.** Most of the Utility's revenue requirements are set by the CPUC in the GRC, which occurs generally every three years. The FERC authorizes the Utility's revenue requirements in annual transmission owner ("TO") rate cases. During 2010, the CPUC will determine the amount of revenue requirements the Utility is authorized to recover beginning in 2011 for its electric and natural gas distribution operations and its electric generation operations in the 2011 GRC, and for its natural gas transportation and storage services in the Gas Transmission and Storage Rate Case. In addition, the FERC will determine the amount of electric transmission revenues the Utility can recover beginning in March 2011. The decisions issued in the three associated rate cases will determine the majority of the Utility's revenue requirements for 2011 and future years. (See "Regulatory Matters" below for a discussion of the Utility's 2011–2013 GRC, the 2011–2014 Gas Transmission and Storage Rate Case, the 2011 TO rate case, and other proceedings.) In addition, the Utility frequently files separate applications requesting the CPUC or the FERC to authorize additional revenue requirements for specific capital expenditure projects such as new power plants, new or upgraded natural gas or electric transmission facilities, the installation of an advanced metering infrastructure, and other infrastructure improvements. (See "Capital Expenditures" below.) The outcome of these regulatory proceedings can be affected by many factors, including general economic conditions, the level of rates, and political and regulatory policies.
- **The Ability of the Utility to Control Costs While Improving Operational Efficiency and Reliability.** The Utility's revenue requirements in the GRC and TO rate case are generally set at a level to allow the Utility the opportunity to recover its basic forecasted operating expenses as well as to earn an ROE and recover depreciation, tax, and interest expense associated with authorized capital expenditures. Differences in the amount or timing of forecasted and actual operating expenses and capital expenditures can affect the Utility's ability to earn its CPUC-authorized rate of return and the amount of PG&E Corporation's income available for common shareholders. The Utility also seeks to make the amount and timing of its capital expenditures consistent with budgeted amounts and timing. When capital expenditures are higher than authorized levels, the Utility incurs associated depreciation, property tax, and interest expense but does not recover GRC or TO revenues to fully offset these expenses or earn an ROE until the increased capital expenditures are added to rate base in future rate cases. Items that could cause higher expenses than provided for in the last GRC primarily relate to the Utility's efforts to maintain its aging electric and natural gas systems' infrastructure, to improve the reliability and safety of its electric and natural gas system, and to improve its information technology infrastructure, support, and security. The Utility continually seeks to achieve

operational efficiencies and improve reliability while creating future sustainable cost savings to offset these higher anticipated expenses. (See "Results of Operations" below.)

- **Capital Structure and Financing.** The CPUC has authorized a capital structure for the Utility's electric and natural gas distribution and electric generation rate base that consists of 52% common equity and 48% debt and preferred stock. This authorized capital structure will remain in effect through 2012. The CPUC also has authorized the Utility to earn a rate of return on each component of its capital structure, including an ROE of 11.35%. These rates will remain in effect through 2010. The rates for 2011 and 2012 are subject to an annual adjustment mechanism that will be triggered if the 12-month October-through-September average yield for the applicable Moody's Investors Service ("Moody's") utility bond index increases or decreases by more than 1% as compared to the applicable benchmark. The amount of the Utility's authorized equity earnings is determined by the 52% equity component, the 11.35% ROE, and the aggregate amount of rate base authorized by the CPUC. The rate of return that the Utility earns on its FERC-jurisdictional rate base is not specifically authorized, but rates are designed to allow the Utility to earn a reasonable rate of return. The Utility's actual equity earnings could be more or less based on a number of factors, including the timing and amount of operating costs and capital expenditures. The CPUC periodically authorizes the aggregate amount of long-term debt and short-term debt that the Utility may issue and authorizes the Utility to recover its related debt financing costs. The timing and amount of the Utility's future financing will depend on various factors, as discussed in "Liquidity and Financial Resources" below. PG&E Corporation regularly contributes equity to the Utility to maintain the Utility's CPUC-authorized capital structure. PG&E Corporation may issue debt or equity in the future to fund these equity contributions.

FORWARD-LOOKING STATEMENTS

This combined annual report and the letter to shareholders that accompanies it contain forward-looking statements that are necessarily subject to various risks and uncertainties. These statements are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report. These forward-looking statements relate to, among other matters, estimated capital expenditures, estimated environmental remediation liabilities, estimated tax liabilities, the anticipated outcome of various regulatory and legal proceedings, estimated future cash flows, and the level of future equity or debt issuances, and are also identified by words such as "assume," "expect," "intend," "plan," "project," "believe," "estimate," "target," "predict," "anticipate," "aim," "may," "might," "should," "would," "could," "goal," "potential," and similar expressions. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

- the Utility's ability to manage capital expenditures and its operating and maintenance expenses within authorized levels;
- the outcome of pending and future regulatory proceedings and whether the Utility is able to timely recover its costs through rates;
- the adequacy and price of electricity and natural gas supplies, and the ability of the Utility to manage and respond to the volatility of the electricity and natural gas markets, including the ability of the Utility and its counterparties to post or return collateral;
- explosions, fires, accidents, mechanical breakdowns, the disruption of information technology and systems, and similar events that may occur while operating and maintaining an electric and natural gas system in a large service territory with varying geographic conditions that can cause unplanned outages, reduce generating output, damage the Utility's assets or operations, subject the Utility to third-party claims for property damage or personal injury, or result in the imposition of civil, criminal, or regulatory fines or penalties on the Utility;
- the impact of storms, earthquakes, floods, drought, wildfires, disease, and similar natural disasters, or acts of terrorism or vandalism, that affect customer demand or that damage or disrupt the facilities, operations, or information technology and systems owned by the Utility, its customers, or third parties on which the Utility relies;
- the potential impacts of climate change on the Utility's electricity and natural gas businesses;
- changes in customer demand for electricity and natural gas resulting from unanticipated population growth or decline, general economic and financial market conditions, changes in technology that include the development of alternative technologies that enable customers to increase their reliance on self-generation, or other reasons;
- the occurrence of unplanned outages at the Utility's two nuclear generating units at the Diablo Canyon Power

Plant ("Diablo Canyon"), the availability of nuclear fuel, the outcome of the Utility's application to renew the operating licenses for Diablo Canyon, and potential changes in laws or regulations promulgated by the NRC or other environmental agencies with respect to the storage of spent nuclear fuel, security, safety, or other matters associated with the operations at Diablo Canyon;

- whether the Utility can maintain the cost savings that it has recognized from operating efficiencies that it has achieved and identify and successfully implement additional sustainable cost-saving measures;
- whether the Utility earns incentive revenues or incurs obligations under incentive ratemaking mechanisms, such as the CPUC's incentive ratemaking mechanism relating to energy savings achieved through implementation of the utilities' customer energy efficiency programs;
- the impact of federal or state laws, or their interpretation, on energy policy and the regulation of utilities and their holding companies;
- whether the new day-ahead, hour-ahead, and real-time wholesale electricity markets established by the California Independent System Operator ("CAISO") that became operational on April 1, 2009 will continue to function effectively and whether the Utility can successfully implement "dynamic pricing" by offering electric rates that can vary with the customer's time of use and are more closely aligned with wholesale electricity prices;
- how the CPUC administers the conditions imposed on PG&E Corporation when it became the Utility's holding company;
- the extent to which PG&E Corporation or the Utility incurs costs and liabilities in connection with litigation that are not recoverable through rates, from insurance, or from other third parties;
- the ability of PG&E Corporation, the Utility, and counterparties to access capital markets and other sources of credit in a timely manner on acceptable terms;
- the impact of environmental laws and regulations and the costs of compliance and remediation;
- the loss of customers due to municipalization of the Utility's electric distribution facilities, the level of "direct access" by which consumers procure electricity from alternative energy providers, implementation of "community choice aggregation," which permits cities and counties to purchase and sell electricity for their local residents and businesses, or other forms of bypass; and
- the outcome of federal or state tax audits and the impact of changes in federal or state tax laws, policies, or regulations.

For more information about the significant risks that could affect the outcome of these forward-looking statements and PG&E Corporation's and the Utility's future financial condition and results of operations, see the discussion in the section entitled "Risk Factors" 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 2009, 2008, and 2007:

	Year ended December 31,		
(in millions)	**2009**	2008	2007
Utility			
Electric operating revenues	**$10,257**	$10,738	$ 9,481
Natural gas operating revenues	**3,142**	3,890	3,757
Total operating revenues	**13,399**	14,628	13,238
Cost of electricity	**3,711**	4,425	3,437
Cost of natural gas	**1,291**	2,090	2,035
Operating and maintenance	**4,343**	4,197	3,872
Depreciation, amortization, and decommissioning	**1,752**	1,650	1,769
Total operating expenses	**11,097**	12,362	11,113
Operating income	**2,302**	2,266	2,125
Interest income	**33**	91	150
Interest expense	**(662)**	(698)	(732)
Other income, net	**59**	28	52
Income before income taxes	**1,732**	1,687	1,595
Income tax provision	**482**	488	571
Net income	**1,250**	1,199	1,024
Preferred stock dividend requirement	**14**	14	14
Income Available for Common Stock	**$ 1,236**	$ 1,185	$ 1,010
PG&E Corporation, Eliminations, and Other(1)			
Operating revenues	**$ –**	$ –	$ (1)
Operating expenses	**3**	5	10
Operating loss	**(3)**	(5)	(11)
Interest income	**–**	3	14
Interest expense	**(43)**	(30)	(30)
Other income (expense), net	**8**	(32)	(9)
Loss before income taxes	**(38)**	(64)	(36)
Income tax benefit	**(22)**	(63)	(32)
Loss from continuing operations	**(16)**	(1)	(4)
Discontinued operations(2)	**–**	154	–
Net income (loss)	**$ (16)**	$ 153	$ (4)
Consolidated Total			
Operating revenues	**$13,399**	$14,628	$13,237
Operating expenses	**11,100**	12,367	11,123
Operating income	**2,299**	2,261	2,114
Interest income	**33**	94	164
Interest expense	**(705)**	(728)	(762)
Other income (expense), net	**67**	(4)	43
Income before income taxes	**1,694**	1,623	1,559
Income tax provision	**460**	425	539
Income from continuing operations	**1,234**	1,198	1,020
Discontinued operations(2)	**–**	154	–
Net income	**1,234**	1,352	1,020
Preferred stock dividend requirement of subsidiary	**14**	14	14
Income Available for Common Shareholders	**$ 1,220**	$ 1,338	$ 1,006

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

(2) Discontinued operations reflect items related to PG&E Corporation's former subsidiary, National Energy & Gas Transmission, Inc. ("NEGT"). See "PG&E Corporation Eliminations and Other" section in "Results of Operations" for further discussion.

UTILITY

The following presents the Utility's operating results for 2009, 2008, and 2007.

Electric Operating Revenues

The Utility's electric operating revenues consist of amounts charged to customers for electricity generation and for electric transmission and distribution services, as well as amounts charged to customers to recover the cost of electric procurement, public purpose, energy efficiency, and demand response programs. The Utility provides electricity to residential, industrial, agricultural, and small and large commercial customers through its own generation facilities and through power purchase agreements with third parties. In addition, a portion of the Utility's customers' demand for electricity ("load") is satisfied by electricity provided under long-term contracts between the California Department of Water Resources ("DWR") and various power suppliers.

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

(in millions)	2009	2008	2007
Electric revenues	**$12,244**	$12,063	$11,710
DWR pass-through revenues(1)	**(1,987)**	(1,325)	(2,229)
Total electric operating revenues	**$10,257**	$10,738	$ 9,481

(1) The Utility acts as a billing and collection agent on behalf of the DWR and remits the amounts collected from customers to the DWR. The Utility's electric operating revenues are reflected net of the amounts remitted to the DWR. (See Note 2 of the Notes to the Consolidated Financial Statements.)

The Utility's total electric operating revenues decreased by $481 million, or 4%, in 2009 compared to 2008, reflecting a decrease in revenues to recover the cost of electricity procurement (which decreased by $714 million) and the cost of public purpose programs (which decreased by $110 million). These costs are passed through to customers and do not impact net income. (See "Cost of Electricity" and "Operating and Maintenance" below.) Electric operating revenues, excluding items passed through to customers, increased by $343 million. This was primarily due to $344 million of increases in authorized base revenues consisting of $103 million for the 2009 attrition adjustment, $35 million for the cost of a second refueling outage at Diablo Canyon, and $206 million representing additional authorized revenue requirements to recover the capital costs of new assets placed in service (such as the Gateway Generating Station, the new steam generators at Diablo Canyon Unit 1 and Unit 2, and the SmartMeter™ advanced metering project) and the associated rate of return. In 2009, the CPUC also authorized the Utility to recover $35 million of costs the Utility incurred during 2000 and 2001 related to efforts taken by the Utility in connection with the proposed divestiture of its hydroelectric generation facilities, as directed by the CPUC.

The Utility's total electric operating revenues increased by $1,257 million, or 13%, in 2008 compared to 2007, reflecting an increase in revenues to recover the cost of electricity procurement (which increased by $976 million) and the cost of public purpose and energy efficiency programs (which increased by $266 million). These increases were partially offset by a $276 million decrease in revenue that was recovered in 2007 for the payment of principal and interest related to the rate reduction bonds ("RRBs") that matured in December 2007. Costs related to electricity procurement, public purpose programs, and the RRBs are passed through to customers and do not impact net income. (See "Cost of Electricity" and "Operating and Maintenance" below.) Electric operating revenues, excluding items passed through to customers, increased by $291 million. This was primarily due to $255 million of increases in authorized base revenues consisting of $103 million for the 2008 attrition adjustment, $56 million for electric transmission revenues, and $96 million representing additional authorized revenue requirements to recover the capital costs of new assets placed in service (such as the new steam generators at Diablo Canyon Unit 2 and the SmartMeter™ advanced metering project) and the associated rate of return.

The Utility's electric operating revenues for 2010 are expected to increase by $68 million due to the attrition adjustment that was authorized by the CPUC in the 2007 GRC. The Utility's electric operating revenues for future years are also expected to increase, as authorized by the FERC in the TO rate cases and by the CPUC in the 2011 GRC. Additionally, the Utility's future electric operating revenues may be impacted by the revenue requirements to recover certain pension contributions as authorized by the CPUC during 2009. The Utility also expects to continue to collect revenue requirements related to CPUC-approved capital expenditures outside the GRC, including capital expenditures for the new Utility-owned generation projects and the SmartMeter™ advanced metering project. Revenues will increase to the extent that the CPUC approves the Utility's proposals for other capital projects. Finally, the CPUC has not yet determined how the existing energy efficiency incentive mechanism will be modified, so the amount of incentive revenues the Utility may earn for the implementation of its programs in 2009 and future years is uncertain. (See "Regulatory Matters" below.)

Cost of Electricity

The Utility's cost of electricity includes costs to purchase power from third parties, certain transmission costs, the cost of fuel used in its generation facilities, and the cost of fuel supplied to other facilities under tolling agreements. The Utility's cost of electricity also includes realized gains and losses on price risk management activities. (See Notes 10 and 11 of the Notes to the Consolidated Financial Statements.) The Utility's cost of electricity is passed through to customers. The Utility's cost of electricity excludes non-fuel costs associated with the Utility's own generation facilities, which are included in Operating and maintenance expense in the Consolidated Statements of Income. The cost of electricity provided under power purchase agreements between the DWR and various power suppliers is also excluded from the Utility's cost of electricity.

The following table provides a summary of the Utility's cost of electricity and the total amount and average cost of purchased power:

(in millions)	**2009**	2008	2007
Cost of purchased power	**$ 3,508**	$ 4,261	$ 3,288
Fuel used in own generation facilities	**203**	164	149
Total cost of electricity	**$ 3,711**	$ 4,425	$ 3,437
Average cost of purchased power per kWh(1)	**$ 0.082**	$ 0.089	$ 0.091
Total purchased power (in millions of kWh)	**42,767**	47,668	36,157

(1) Kilowatt-hour

The Utility's total cost of electricity decreased by $714 million, or 16%, in 2009 compared to 2008, primarily due to an 8% decrease in the average cost of purchased power and a 10% decrease in the total volume of purchased power. The decrease in the average cost of purchased power was primarily driven by lower market prices for electricity and gas. The decrease in the volume of purchased power primarily resulted from an increase in the amount of power generated by facilities owned by the Utility such as the new Gateway Generating Station. The Utility's mix of resources is determined by the availability of the Utility's own electricity generation and the cost-effectiveness of each source of electricity.

The Utility's total cost of electricity increased by $988 million, or 29%, in 2008 compared to 2007, primarily due to a 32% increase, or an 11,511 million kWh increase, in total volume of purchased power. Following the DWR's termination of its power purchase agreement with Calpine Corporation in December 2007, the volume of power provided by the DWR to the Utility's customers decreased by 8,784 million kWh. As a result, the Utility was required to increase its purchases of power from third parties to meet customer load. In addition, the Utility increased its power purchases in 2008 during the scheduled extended outage at Diablo Canyon Unit 2 to replace the four steam generators. The extended outage lasted from February through mid-April 2008, in comparison to the planned refueling outage of Diablo Canyon Unit 1 that occurred entirely in May 2007. Increases in market prices during the first half of 2008 were entirely offset by a decrease in market prices during the second half of 2008 and price risk management activity.

Various factors will affect the Utility's future cost of electricity, including the market prices for electricity and natural gas, the level of hydroelectric and nuclear power that the Utility produces, the cost of procuring more renewable energy, changes in customer demand, and the amount and timing of power purchases needed to replace power previously supplied under the DWR contracts as those contracts expire or are terminated, novated, or renegotiated.

The Utility's future cost of electricity also may be affected by federal or state legislation or rules that may be adopted to regulate the emissions of greenhouse gases ("GHG") from the Utility's electricity generating facilities or the generating facilities from which the Utility procures electricity. In particular, costs are likely to increase in the future when California's statewide GHG emissions reduction law is implemented. (See "Environmental Matters" and "Risk Factors" below.)

Natural Gas Operating Revenues

The Utility sells natural gas and natural gas transportation services. The Utility's transportation services are provided by a transmission system and a distribution system. The transmission system transports gas throughout its service territory for delivery to the Utility's distribution system, which, in turn, delivers natural gas to end-use customers. The transmission system also delivers natural gas to large end-use customers who are connected directly to the transmission system. In addition, the Utility delivers natural gas to off-system markets, primarily in southern California.

The Utility's natural gas customers consist of two categories: residential and smaller commercial customers known as "core" customers and industrial and larger commercial customers known as "non-core" customers. The Utility provides natural gas transportation 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 either the Utility or alternate energy service providers. The Utility does not procure natural gas for non-core customers. When the Utility provides both transportation and natural gas supply, the Utility refers to the combined service as "bundled natural gas service." In 2009, core customers represented over 99% of the Utility's total customers and 38% of its total natural gas deliveries, while non-core customers comprised less than 1% of the Utility's total customers and 62% of its total natural gas deliveries.

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

(in millions)	2009	2008	2007
Bundled natural gas revenues	**$2,794**	$3,557	$3,417
Transportation service-only revenues	**348**	333	340
Total natural gas operating revenues	**$3,142**	$3,890	$3,757
Average bundled revenue per Mcf[1] of natural gas sold	**$11.04**	$13.52	$12.94
Total bundled natural gas sales (in millions of Mcf)	**253**	263	264

(1) One thousand cubic feet

The Utility's total natural gas operating revenues decreased by $748 million, or 19%, in 2009 compared to 2008, primarily due to a $799 million decrease in the total cost of natural gas. This cost is passed through to customers and generally does not impact net income. (See "Cost of Natural Gas" below.) Natural gas operating revenues, excluding items passed through to customers, increased by $51 million. This was primarily due to $53 million of increase in authorized base revenues consisting of $22 million for the 2009 attrition adjustments, $10 million as a result of the 2007 Gas Accord IV Settlement Agreement, and $21 million representing additional authorized revenue requirements to recover the capital costs of new assets placed in service (such as the SmartMeter™ advanced metering project).

The Utility's natural gas operating revenues increased by $133 million, or 4%, in 2008 compared to 2007, primarily due to an increase in costs of natural gas of $55 million and public purpose programs of $24 million, which are passed through to customers and generally do not have an impact on earnings. Natural gas operating revenues, excluding items passed through to customers, increased by $54 million, primarily due to a $22 million increase in base revenue requirements as a result of attrition adjustments authorized in the 2007 GRC and an increase in natural gas revenue requirements of $25 million to fund the SmartMeter™ advanced metering project.

The Utility's natural gas operating revenues for 2010 are expected to increase by $22 million due to attrition adjustments that were authorized by the CPUC in the 2007 GRC. The Utility's future natural gas operating revenues for 2011 through 2014 will depend on the amount of revenue requirements authorized by the CPUC in the Utility's 2011 GRC and the Gas Transmission and Storage rate case. (See "Regulatory Matters" below.) In addition, the Utility expects future natural gas operating revenues to increase to the extent that the CPUC approves the Utility's separately funded projects. (See "Capital Expenditures" below.) Finally, the CPUC has not yet determined how the existing energy efficiency incentive mechanism will be modified, so the amount of incentive revenues that the Utility may earn for the implementation of its programs in 2009 and future years is uncertain. (See "Regulatory Matters" below.)

Cost of Natural Gas

The Utility's cost of natural gas includes the purchase costs of natural gas, transportation costs on interstate pipelines, and gas storage costs but excludes the transportation costs on intrastate pipelines for core and non-core customers, which are included in Operating and maintenance expense in the Consolidated Statements of Income. The Utility's cost of natural gas also includes realized gains and losses on price risk management activities. (See Notes 10 and 11 of the Notes to the Consolidated Financial Statements.)

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

(in millions)	2009	2008	2007
Cost of natural gas sold	**$1,130**	$1,955	$1,859
Transportation cost of natural gas sold	**161**	135	176
Total cost of natural gas	**$1,291**	$2,090	$2,035
Average cost per Mcf of natural gas sold	**$ 4.47**	$ 7.43	$ 7.04
Total natural gas sold (in millions of Mcf)	**253**	263	264

The Utility's total cost of natural gas decreased by $799 million, or 38%, in 2009 compared to 2008, primarily due to decreases in the average market price of natural gas.

The Utility's total cost of natural gas increased by $55 million, or 3%, in 2008 compared to 2007, primarily due to increases in the average market price of natural gas purchased. The increase was partially offset by a $23 million refund that the Utility received as part of a settlement with TransCanada's Gas Transmission Northwest Corporation related to 2007 gas transmission capacity rates.

The Utility's future cost of natural gas will be affected by the market price of natural gas and changes in customer demand. In addition, the Utility's future cost of gas may be affected by federal or state legislation or rules to regulate the GHG emissions from the Utility's natural gas transportation and distribution facilities and from natural gas consumed by the Utility's customers.

Operating and Maintenance

Operating and maintenance expenses consist mainly of the Utility's costs to operate and maintain its electricity and natural gas facilities, customer billing and service expenses, the cost of public purpose programs, and administrative and general expenses. Operating and maintenance expenses are influenced by wage inflation; changes in liabilities for employee benefits; property taxes; the timing and length of Diablo Canyon refueling outages; the occurrence of storms, wildfires, and other events causing outages and damages in the Utility's service territory; environmental remediation costs; legal costs; materials costs; the level of uncollectible customer accounts; and various other factors. Although some of the Utility's operating and maintenance expenses, like the cost of public purpose programs, are passed through to customers and generally do not impact net income, many other expenses are less predictable and less controllable and do impact net income. The Utility's ability to earn its authorized rate of return depends in large part on the success of its ability to manage these expenses and to achieve operational and cost efficiencies.

The Utility's operating and maintenance expenses (including costs passed through to customers) increased by $146 million, or 3%, in 2009 compared to 2008. During 2009, the pass-through costs of public purpose programs decreased by $111 million as compared to the level of program spending in 2008. Excluding costs passed through to customers, operating and maintenance expenses increased by $257 million, primarily due to approximately $100 million of costs to perform accelerated natural gas leak surveys and associated remedial work, $67 million of employee severance costs incurred due to the reduction of approximately 2% of the Utility's workforce, $42 million of costs related to the SmartMeter™ advanced metering project, and $35 million of costs for the second refueling outage at Diablo Canyon. The remaining increase consists primarily of employee wage and benefit costs that were partially offset by lower storm-related costs as compared to 2008 when costs were incurred in connection with the January 2008 winter storm.

The Utility's operating and maintenance expenses increased by $325 million, or 8%, in 2008 compared to 2007. This increase reflects a $290 million increase in the cost of public purpose programs compared to the level of spending in 2007, as program spending typically increases in the last year of a three-year program cycle. Program costs are passed through to customers and generally do not impact net income. Excluding items passed through to customers, operating and maintenance expenses increased by $35 million, primarily due to $39 million of costs to conduct expanded natural gas leak surveys in parts of the Utility's service territory and to make related repairs in an effort to improve operating and maintenance processes in the Utility's natural gas system, $38 million of labor expenses consisting of the labor costs that were incurred in connection with the January 2008 winter storm (there was no similar storm in the same period in 2007), and $10 million of maintenance costs due to the longer duration of the planned outage of Diablo Canyon Unit 2 in 2008 compared to the Diablo Canyon Unit 1 outage in 2007. These increases were partially offset by a decrease of $12 million of costs as compared to 2007, when the CPUC ordered the Utility to make customer refunds related to billing practices.

The Utility anticipates that it will incur higher costs in the future to improve the safety and reliability of its electric and natural gas system infrastructure and to maintain its aging electric distribution system. The Utility also expects that it will incur higher expenses in future periods to obtain permits or comply with permitting requirements, including costs associated with renewing FERC licenses for the Utility's hydroelectric generation facilities. Also, in January 2010, the Utility incurred approximately $20 million of additional expenses in connection with winter storms. To help offset these increased costs, the Utility intends to continue its efforts to identify and implement initiatives to achieve operational efficiencies and to create future sustainable cost savings.

Depreciation, Amortization, and Decommissioning

The Utility's depreciation and amortization expense consists of depreciation and amortization on plant and regulatory assets, and decommissioning expenses associated with fossil and nuclear decommissioning. The Utility's depreciation, amortization, and decommissioning expenses increased by $102 million, or 6%, in 2009 compared to 2008, primarily due to an increase in authorized capital additions and depreciation rate changes.

The Utility's depreciation, amortization, and decommissioning expenses decreased by $119 million, or 7% in 2008 compared to 2007, mainly due to decreases in amortization expense related to the RRB regulatory asset. The RRB regulatory asset was fully recovered through rates when the RRBs matured in December 2007; therefore, no amortization was recorded in 2008. These decreases were partially offset by increases to depreciation expense primarily due to capital additions and depreciation rate changes.

The Utility's depreciation expense for future periods is expected to increase as a result of an overall increase in capital expenditures and implementation of depreciation rates authorized by the CPUC. Depreciation expenses in subsequent years will be determined based on rates set by the CPUC in the 2011 GRC and the 2011 Gas Transmission and Storage rate case, and by the FERC in future TO rate cases.

Interest Income

The Utility's interest income decreased by $58 million, or 64%, in 2009 compared to 2008, primarily due to lower interest rates affecting various regulatory balancing accounts and regulatory assets and lower balances in those accounts. In addition, interest income decreased due to lower interest rates earned on funds held in escrow pending the disposition of disputed claims that had been made in the Utility's proceeding under Chapter 11 of the U.S. Bankruptcy Code ("Chapter 11"). (See Note 14 of the Notes to the Consolidated Financial Statements for information about the Chapter 11 disputed claims.) These decreases were partially offset by an increase in interest income for the recovery of interest on previously incurred costs related to the Utility's hydroelectric generation facilities.

The Utility's interest income decreased by $59 million, or 39%, in 2008 as compared to 2007, when the Utility received $16 million in interest income on a federal tax refund. In addition, decreases in interest income were due to lower interest rates earned on funds held in escrow related to Chapter 11 disputed claims and a lower escrow balance reflecting settlements of Chapter 11 disputed claims.

The Utility's interest income in future periods will be primarily affected by changes in the balance of funds held in escrow pending resolution of the Chapter 11 disputed claims, changes in regulatory balancing accounts, and changes in interest rates.

Interest Expense

The Utility's interest expense decreased by $36 million, or 5%, in 2009 as compared to 2008. This was primarily attributable to lower interest rates and outstanding balances on liabilities that the Utility incurs interest expense on (such as the liability for Chapter 11 disputed claims and various regulatory balancing accounts). This decrease was partially offset by higher outstanding balances for long-term debt due to timing of senior note issuances. (See Note 4 of the Notes to the Consolidated Financial Statements for further discussion.)

The Utility's interest expense decreased by $34 million, or 5%, in 2008 as compared to 2007, primarily due to a decrease in interest expense accrued on the liability for Chapter 11 disputed claims as the FERC-mandated interest rates declined. Additionally, interest expense decreased due to the reduction in the outstanding balance of Energy Recovery Bonds ("ERB") and the maturity of the RRBs in December 2007. These decreases were partially offset by additional interest expense primarily related to $1.8 billion in senior notes that were issued in March, October, and November 2008.

The Utility's interest expense in future periods will be impacted by changes in interest rates, changes in the balance of the liability for Chapter 11 disputed claims, changes in regulatory balancing accounts, and changes in the amount of debt outstanding as long-term debt matures and additional long-term debt is issued. (See "Liquidity and Financial Resources" below.)

Other Income, Net

The Utility's other income, net increased by $31 million, or 111%, in 2009 compared to 2008, when the Utility incurred costs to oppose the statewide initiative related to renewable energy (Proposition 7) and the City of San Francisco's municipalization efforts. These costs also caused the Utility's other income, net to decrease by $24 million, or 46%, in 2008 compared to 2007.

The Utility estimates it will incur approximately $25 million to $35 million in 2010 to support a California ballot initiative that proposes to require local governments to gain voter support before using taxpayer money to establish electric service. These costs will not be recoverable in rates.

Income Tax Provision

The Utility's income tax provision decreased by $6 million, or 1%, in 2009 compared to 2008. The effective tax rates were 27.8% and 28.9% for 2009 and 2008, respectively. The lower effective tax rate for 2009 was primarily due to the recognition of California tax and related interest benefits attributable to the settlement of various federal tax issues. (See Note 9 of the Notes to the Consolidated Financial Statements for further discussion.)

The Utility's income tax provision decreased by $83 million, or 15%, in 2008 compared to 2007. The effective tax rates were 28.9% and 35.8% for 2008 and 2007, respectively. The decrease in the effective tax rate for 2008 was primarily due to a settlement of federal tax audits for the tax years 2001 through 2004 and approval by the Internal Revenue Service of the Utility's change in accounting method for the capitalization of indirect service costs for tax years 2001 through 2004.

PG&E Corporation and the Utility are entitled to a tax-exempt federal subsidy ("Medicare Part D subsidy") as established by the Medicare Prescription Drug, Improvement, and Modernization Act of 2003. The health care reform legislation proposed by the U.S. Congress would eliminate the tax deduction for the Medicare Part D subsidy included in the Utility's accrued postretirement medical costs. (See Note 13 of the Notes to the Consolidated Financial Statements for further discussion). The impact of this legislation could result in a charge to earnings of up to $25 million representing a reduction in tax benefits related to contributions of future subsidies received to the benefit plan trusts.

PG&E CORPORATION, ELIMINATIONS, AND OTHER

Operating Revenues and Expenses

PG&E Corporation's revenues consist mainly of billings to its affiliates for services rendered, all of which are eliminated in consolidation. PG&E Corporation's operating expenses consist mainly of employee compensation and payments to third parties for goods and services. Generally, PG&E Corporation's operating expenses are allocated to affiliates. These allocations are made without mark-up and are eliminated in consolidation. PG&E Corporation's interest expense relates to its 9.50% convertible subordinated notes and 5.75% senior notes, and is not allocated to affiliates.

There were no material changes to PG&E Corporation's operating revenues and expenses in 2009 compared to 2008 and 2008 compared to 2007.

Other Income (Expense), Net

PG&E Corporation's other income, net increased by $40 million, or 125%, in 2009 compared to 2008, primarily due to investment-related gains in the rabbi trusts established in connection with the non-qualified deferred compensation plans.

PG&E Corporation's other expense, net increased by $23 million, or 255%, in 2008 compared to 2007, primarily due to an increase in investment losses in the rabbi trusts established in connection with the non-qualified deferred compensation plans.

Income Tax Benefit

PG&E Corporation's income tax benefit decreased by $41 million, or 65%, in 2009 compared to 2008, primarily due to a settlement of federal tax audits for the tax years 2001 to 2004 in 2008 with no similar adjustment in 2009.

PG&E Corporation's income tax benefit increased by $31 million, or 97%, in 2008 compared to 2007, primarily due to a settlement of federal tax audits for the tax years 2001 through 2004 in 2008 with no similar adjustment in 2007.

Discontinued Operations

In the fourth quarter of 2008, PG&E Corporation reached a settlement of federal tax audits of tax years 2001 through 2004 and recognized after-tax income of $257 million, including $154 million related to losses incurred and synthetic fuel tax credits claimed by PG&E Corporation's former subsidiary, National Energy & Gas Transmission, Inc. ("NEGT"). As a result, PG&E Corporation recorded $154 million in income from discontinued operations in 2008. (See Note 9 of the Notes to the Financial Statements for further discussion.) No similar amount was recognized in 2009.

LIQUIDITY AND FINANCIAL RESOURCES

OVERVIEW

The Utility's ability to fund operations depends on the levels of its operating cash flow and access to the capital markets. The levels of the Utility's operating cash and short-term debt fluctuate as a result of seasonal demand for electricity and natural gas, volatility in energy commodity costs, collateral requirements related to price risk management activity, the timing and amount of tax payments or refunds, and the timing and effect of regulatory decisions and financings, among other factors. The Utility generally utilizes equity contributions from PG&E Corporation and long-term senior unsecured debt issuances to fund debt maturities and capital expenditures and to maintain its CPUC-authorized capital structure. The Utility relies on short-term debt, including commercial paper, to fund temporary financing needs. On May 7, 2009, the CPUC increased the Utility's short-term borrowing authority by $1.5 billion, for an aggregate authority of $4.0 billion, including $500 million that is restricted to certain contingencies.

PG&E Corporation's ability to fund operations, make scheduled principal and interest payments, refinance debt, fund Utility equity contributions as needed for the Utility to maintain its CPUC-authorized capital structure, and make dividend payments primarily depends on the level of cash distributions received from the Utility and PG&E Corporation's access to the capital markets.

The following table summarizes PG&E Corporation's and the Utility's cash positions:

	December 31,	
(in millions)	**2009**	2008
PG&E Corporation	**$ 193**	$ 167
Utility	**334**	52
Total consolidated cash and cash equivalents	**527**	219
Utility restricted cash	**633**	1,290
Total consolidated cash, including restricted cash	**$1,160**	$1,509

Restricted cash primarily consists of cash held in escrow pending the resolution of the remaining disputed claims filed in the Utility's reorganization proceeding under Chapter 11. PG&E Corporation and the Utility maintain separate bank accounts. PG&E Corporation and the Utility primarily invest their cash in money market funds.

Credit Facilities

The following table summarizes PG&E Corporation's and the Utility's outstanding commercial paper and credit facilities at December 31, 2009:

(in millions) **At December 31, 2009**

Authorized Borrower	Facility	Termination Date	Facility Limit	Letters of Credit Outstanding	Cash Borrowings	Commercial Paper Backup	Availability
PG&E Corporation	Revolving credit facility	February 2012	**$ 187(1)**	**$ –**	**$–**	**N/A**	**$ 187**
Utility	Revolving credit facility	February 2012	**1,940(2)**	**252**	**–**	**$ 333**	**1,355**
Total credit facilities			**$2,127**	**$252**	**$–**	**$ 333**	**$1,542**

(1) Includes an $87 million sublimit for letters of credit and a $100 million sublimit for "swingline" loans, defined as loans that are made available on a same-day basis and are repayable in full within 30 days.
(2) Includes a $921 million sublimit for letters of credit and a $200 million sublimit for swingline loans.

At December 31, 2009, PG&E Corporation and the Utility were in compliance with all covenants under these revolving credit facilities. (See Note 4 of the Notes to the Consolidated Financial Statements for further detail.)

2009 Financings

The following table summarizes PG&E Corporation's and the Utility's debt issuances in 2009:

(in millions)	Issue Date	Amount
PG&E Corporation		
Senior Notes		
5.75%, due 2014	March 12	**$ 350**
Utility		
Senior Notes		
6.25%, due 2039	March 6	**550**
Floating rate, due 2010	June 11	**500**
5.40%, due 2040	November 18	**550**
Total Utility senior notes		**1,600**
Pollution control bonds		
Series 2009 A and B, variable rates, due 2026	September 1	**149**
Series 2009 C and D, variable rates, due 2016	September 1	**160**
Total pollution control bonds		**309**
Total Utility debt		**1,909**
Total debt issuances in 2009		**$2,259**

The net proceeds from the various Utility senior notes in 2009 were used to finance capital expenditures and for general working capital and other corporate purposes. The net proceeds from the pollution control bonds were used to repurchase the corresponding series of 2008 pollution control bonds. (See Note 4 of the Notes to the Consolidated Financial Statements for further detail.)

During 2009, PG&E Corporation issued 6,773,290 shares of common stock upon the exercise of employee stock options and under its 401(k) plan and Dividend Reinvestment and Stock Purchase Plan, generating $219 million of cash. The equity issuances, combined with the proceeds from the issuance of $350 million of senior notes and other funds, allowed PG&E Corporation to contribute $718 million of cash to the Utility in 2009 to ensure that the Utility had adequate capital to fund its capital expenditures and to maintain the 52% common equity ratio authorized by the CPUC.

Future Financing Needs

The amount and timing of the Utility's future financing needs will depend on various factors, including the conditions in the capital markets, the timing and amount of forecasted capital expenditures, and the amount of cash internally generated through normal business operations, among other factors. The Utility's future financing needs will also depend on the timing of the resolution of the Chapter 11 disputed claims and the amount of interest on these claims that the Utility will be required to pay. (See Note 14 of the Notes to the Consolidated Financial Statements.)

PG&E Corporation may issue debt or equity in the future to fund the Utility's operating expenses and capital expenditures to the extent that internally generated funds are not available. Assuming that PG&E Corporation and the Utility can access the capital markets on reasonable terms, PG&E Corporation and the Utility believe that the Utility's cash flow from operations, existing sources of liquidity, and future financings will provide adequate resources to fund operating activities, meet anticipated obligations, and finance future capital expenditures.

Credit Ratings

As of January 31, 2010, PG&E Corporation's and the Utility's credit ratings from Moody's and Standard & Poor's ("S&P") ratings service were as follows:

	Moody's	S&P
Utility		
Corporate credit rating	A3	BBB+
Senior unsecured debt	A3	BBB+ to A-2
Credit facility	A3	BBB+
Pollution control bonds backed by letters of credit	Not rated to Aaa/VMIG1	AA-/A-1+ to AAA/A-1+
Pollution control bonds backed by bond insurance	A3	BBB+ to A
Pollution control bonds – nonbacked	A3	BBB+
Preferred stock	Baa2	BBB-
Commercial paper program	P-2	A-2
PG&E Energy Recovery Funding LLC		
Energy recovery bonds	Aaa	AAA
PG&E Corporation		
Corporate credit rating	Baa1	BBB+
Convertible subordinated notes	Baa1	BBB+
Senior unsecured debt	Baa1	BBB
Credit facility	Baa1	Not rated

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.

Dividends

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 Boards of Directors of PG&E Corporation and the Utility have each adopted a target dividend payout ratio range of 50% to 70% of earnings. Dividends paid by PG&E Corporation and the Utility are expected to remain in the lower end of the target payout ratio range so that more internal funds are readily available to support each company's capital investment needs. Each Board of Directors retains authority to change the respective common stock dividend policy and dividend payout ratio at any time, especially if unexpected events occur that would change its view as to the prudent level of cash conservation. No dividend is payable unless and until declared by the applicable Board of Directors.

In addition, the declaration of the Utility's dividends is subject to the CPUC-imposed conditions that the Utility maintain on average its CPUC-authorized capital structure and that the Utility's capital requirements, 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, be given first priority.

During 2009, the Utility paid common stock dividends totaling $624 million to PG&E Corporation. During 2009, PG&E Corporation paid common stock dividends of $1.65 per share, totaling $590 million, net of $17 million that was reinvested in additional shares of common stock by participants in the Dividend Reinvestment and Stock Purchase Plan. On December 16, 2009, the Board of Directors of PG&E Corporation declared a dividend of $0.42 per share, totaling $157 million, which was paid on January 15, 2010 to shareholders of record on December 31, 2009. On February 17, 2010, the Board of Directors of PG&E Corporation declared a dividend of $0.455 per share, payable on April 15, 2010, to shareholders of record on March 31, 2010.

During 2009, the Utility paid cash dividends to holders of its outstanding series of preferred stock totaling $14 million. On December 16, 2009, the Board of Directors of the Utility declared a cash dividend on its outstanding series of preferred stock totaling $4 million that was paid on February 15, 2010 to preferred shareholders of record on January 29, 2010. On February 17, 2010, the Board of Directors of the Utility declared a cash dividend on its outstanding series of preferred stock, payable on May 15, 2010, to shareholders of record on April 30, 2010.

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 2009, 2008, and 2007 were as follows:

(in millions)	**2009**	2008	2007
Net income	**$1,250**	$1,199	$1,024
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	**1,927**	1,838	1,956
Allowance for equity funds used during construction	**(94)**	(70)	(64)
Deferred income taxes and tax credits, net	**787**	593	43
Other changes in noncurrent assets and liabilities	**6**	(25)	188
Effect of changes in operating assets and liabilities:			
Accounts receivable	**157**	(83)	(6)
Inventories	**109**	(59)	(41)
Accounts payable	**(33)**	(137)	(196)
Disputed claims and customer refunds	**(700)**	–	–
Income taxes receivable/payable	**21**	43	56
Regulatory balancing accounts, net	**(521)**	(394)	(567)
Other current assets	**(2)**	(223)	170
Other current liabilities	**24**	90	24
Other	**(27)**	(6)	(46)
Net cash provided by operating activities	**$2,904**	$2,766	$2,541

During 2009, net cash provided by operating activities increased $138 million compared to the same period in 2008, primarily due to the collection of $821 million in rates to recover an under-collection in the Utility's energy resource recovery balancing account that was incurred in 2008 due to higher than expected energy procurement costs. (See Note 3 of the Notes to the Consolidated Financial Statements.) The increase in operating cash flows also reflects a decline of $520 million in net collateral paid by the Utility related to price risk management activities in 2009. Collateral payables and receivables are included in Other changes in noncurrent assets and liabilities, Other current assets, and Other current liabilities in the table above. (See Note 10 of the Notes to the Consolidated Financial Statements.) Operating cash flows in 2009 were also favorably impacted by an increase of $75 million due to the timing and amount of various tax settlements and payments. (See Note 9 of the Notes to the Consolidated Financial Statements for further discussion.)

Increases in operating cash flows in 2009 were partially offset by a $700 million payment to the California Power Exchange to reduce the Utility's liability for the remaining net disputed claims (see Note 14 of the Notes to the Consolidated Financial Statements), a refund of $230 million received by the Utility in 2008 from the California Energy Commission with no similar refund in 2009, and the subsequent return of this $230 million refund to customers in 2009 (see Note 3 of the Notes to the Consolidated Financial Statements).

During 2008, net cash provided by operating activities increased by $225 million compared to the same period in 2007, primarily due to an increase in net income tax refunds received of $689 million and an increase of $230 million for a refund received by the Utility from the California Energy Commission with no similar refund in 2007. These increases in operating cash flows were partially offset by an increase of $459 million in net collateral paid by the Utility related to price risk management activities in 2008 reflecting declining natural gas prices.

Various factors can affect the Utility's future operating cash flows, including the timing of cash collateral payments and receipts related to price risk management activity. The Utility's cash collateral activity will fluctuate based on changes in the Utility's net credit exposure to counterparties, which primarily depends on electricity and gas price movement. The Utility's operating cash flows also will be impacted by electricity procurement costs and the timing of rate adjustments authorized to recover these costs. The CPUC has established a balancing account mechanism to adjust the Utility's electric rates whenever the forecasted aggregate over-collections or under-collections of the Utility's electric procurement costs for the current year exceed 5% of the Utility's prior-year generation revenues, excluding generation revenues for DWR contracts.

Investing Activities

The Utility's investing activities consist of construction of new and replacement facilities necessary to deliver safe and reliable electricity and natural gas services to its customers. Cash used in investing activities depends primarily upon the amount and timing of the Utility's capital expenditures, which can be affected by many factors, including the timing of regulatory approvals, the occurrence of storms and other events causing outages or damages to the Utility's infrastructure, and the completion of electricity and natural gas reliability improvement projects.

Net cash used in investing activities also includes the proceeds from sales of nuclear decommissioning trust investments largely offset by the amount of cash used to purchase new nuclear decommissioning trust investments. The Utility's nuclear power facilities consist of two units at Diablo Canyon and the retired facility at Humboldt Bay. Nuclear decommissioning requires the safe removal of the 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. The Utility makes contributions to trust funds to provide for the eventual decommissioning of each nuclear unit.

The Utility's cash flows from investing activities for 2009, 2008, and 2007 were as follows:

(in millions)	**2009**	2008	2007
Capital expenditures	**$(3,958)**	$(3,628)	$(2,768)
Decrease in restricted cash	**666**	36	185
Proceeds from sales of nuclear decommissioning trust investments	**1,351**	1,635	830
Purchases of nuclear decommissioning trust investments	**(1,414)**	(1,684)	(933)
Other	**11**	1	21
Net cash used in investing activities	**$(3,344)**	$(3,640)	$(2,665)

Net cash used in investing decreased by $296 million in 2009 compared to 2008, primarily due to a $700 million decrease in the restricted cash balance that resulted from a payment to the California Power Exchange to reduce the Utility's liability for the remaining net disputed claims (see Note 14 of the Notes to the Consolidated Financial Statements), partially offset by an increase of $330 million in capital expenditures. Net cash used in investing activities increased $975 million in 2008 compared to 2007, primarily due to an increase of $860 million in 2008 of capital expenditures. The increase in capital expenditures for both 2009 and 2008 as compared to the prior year was for installing the SmartMeter™ advanced metering infrastructure, generation facility spending, replacing and expanding gas and electric distribution systems, and improving the electric transmission infrastructure. (See "Capital Expenditures" below.)

Future cash flows used in investing activities are largely dependent on expected capital expenditures. (See "Capital Expenditures" below for further discussion of expected spending and significant capital projects.)

Financing Activities

The Utility's cash flows from financing activities for 2009, 2008, and 2007 were as follows:

(in millions)	**2009**	2008	2007
Borrowings under accounts receivable facility and revolving credit facility	**$ 300**	$ 533	$ 850
Repayments under accounts receivable facility and revolving credit facility	**(300)**	(783)	(900)
Net issuance (repayments) of commercial paper, net of discount of $3 million in 2009, $11 million in 2008, and $1 million in 2007	**43**	6	(209)
Proceeds from issuance of short-term debt, net of issuance costs of $1 million in 2009	**499**	–	–
Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $25 million in 2009, $19 million in 2008, and $16 million in 2007	**1,384**	2,185	1,184
Long-term debt matured or repurchased	**(909)**	(454)	–
Rate reduction bonds matured	**–**	–	(290)
Energy recovery bonds matured	**(370)**	(354)	(340)
Preferred stock dividends paid	**(14)**	(14)	(14)
Common stock dividends paid	**(624)**	(568)	(509)
Equity contribution	**718**	270	400
Other	**(5)**	(36)	23
Net cash provided by financing activities	**$ 722**	$ 785	$ 195

In 2009, net cash provided by financing activities decreased by $63 million compared to 2008. In 2008, net cash provided by financing activities increased by $590 million compared to 2007. Cash provided by or used in financing activities is driven by the Utility's financing needs, which depend on the level of cash provided by or used in operating activities and the level of cash provided by or used in investing activities. The Utility generally utilizes long-term senior unsecured debt issuances and equity contributions from PG&E Corporation to fund debt maturities and capital expenditures and to maintain its CPUC-authorized capital structure, and relies on short-term debt to fund temporary financing needs.

PG&E CORPORATION

With the exception of dividend payments, interest, common stock issuance, the senior note issuance of $350 million in March 2009, net tax refunds of $189 million, and transactions between PG&E Corporation and the Utility, PG&E Corporation had no material cash flows on a stand-alone basis for the years ended December 31, 2009, 2008, and 2007.

CONTRACTUAL COMMITMENTS

The following table provides information about PG&E Corporation's and the Utility's contractual commitments at December 31, 2009.

		Payment due by period			
(in millions)	**Total**	Less Than 1 Year	1–3 Years	3–5 Years	More Than 5 Years
Contractual Commitments:					
Utility					
Long-term debt[1]:					
Fixed rate obligations	**$16,141**	$ 637	$1,547	$2,391	$11,566
Variable rate obligations	**1,397**	3	956	58	380
Energy recovery bonds[2]	**1,306**	435	871	–	–
Purchase obligations:					
Power purchase agreements[3]:					
Qualifying facilities	**11,163**	1,326	2,265	2,006	5,566
Renewable contracts	**34,725**	626	1,844	2,009	30,246
Irrigation district and water agencies	**335**	74	132	67	62
Other power purchase agreements	**3,234**	257	706	666	1,605
Natural gas supply and transportation	**1,080**	660	212	93	115
Nuclear fuel	**1,657**	134	178	249	1,096
Pension and other benefits[4]	**1,138**	280	531	327	–
Capital lease obligations[5]	**404**	50	100	92	162
Operating leases	**119**	22	39	32	26
Preferred dividends[6]	**70**	14	28	28	–
Other commitments	**18**	18	–	–	–
PG&E Corporation					
Long-term debt[1]:					
Fixed rate obligations	**725**	310	40	375	–

(1) Includes interest payments over the terms of the debt. Interest is calculated using the applicable interest rate at December 31, 2009 and outstanding principal for each instrument with the terms ending at each instrument's maturity. Variable rate obligations consist of bonds, due in 2016-2026, backed by letters of credit which expire in 2011 and 2012. These bonds are subject to mandatory redemption unless the letters of credit are extended or replaced or if applicable to the series, the issuer consents to the continuation of these bonds without a credit facility. Accordingly, these bonds have been classified for repayment purposes in 2011 and 2012. (See Note 4 of the Notes to the Consolidated Financial Statements.)

(2) Includes interest payments over the terms of the bonds. (See Note 5 of the Notes to the Consolidated Financial Statements.)

(3) This table does not include DWR allocated contracts because the DWR is legally and financially responsible for these contracts and payments.

(4) 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. (See Note 13 of the Notes to the Consolidated Financial Statements.)

(5) See Note 16 of the Notes to the Consolidated Financial Statements.

(6) Based on historical performance, it is assumed for purposes of the table above that dividends are payable within a fixed period of five years.

As shown in the table above, the Utility's commitments under the many renewable power purchase agreements that the Utility has entered into are expected to grow significantly, assuming that the facilities are timely developed. These costs are expected to be passed on to customers through rate adjustments.

The contractual commitments table above excludes potential commitments associated with the conversion of existing overhead electric facilities to underground electric facilities. At December 31, 2009, the Utility was committed to spending approximately $237 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 $40 million to $80 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.

The contractual commitments table above also excludes potential payments associated with unrecognized tax benefits. Due to the uncertainty surrounding tax audits, PG&E Corporation and the Utility cannot make reliable estimates of the amount and period of future payments to major tax jurisdictions related to unrecognized tax benefits. Matters relating to tax years that remain subject to examination are discussed in Note 9 of the Notes to the Consolidated Financial Statements.

CAPITAL EXPENDITURES

The Utility's capital expenditures for property, plant, and equipment totaled $3.9 billion in 2009, $3.7 billion in 2008, and $2.8 billion in 2007. The Utility expects that capital expenditures will total approximately $4.0 billion or more in 2010. The amount of capital expenditures differs from the amount of rate base additions used for regulatory purposes primarily because capital expenditures are not added to rate base until the assets are placed in service. In addition, the difference can be affected by the varying amounts or rates of depreciation used for regulatory and accounting purposes. The Utility's weighted average rate base in 2009 was $19.8 billion. Based on the estimated capital expenditures for 2010, the Utility projects a weighted average rate base of approximately $21.4 billion for 2010. The Utility forecasts that it will make various capital investments in its electric and natural gas transmission and distribution infrastructure to maintain and improve system reliability, safety, and customer service; to extend the life of or replace existing infrastructure; and to add new infrastructure to meet already authorized growth. The CPUC authorized most of the Utility's revenue requirements to recover forecasted capital expenditures in multi-year GRCs and gas transmission and storage rate cases. The FERC authorizes revenue requirements to recover forecasted capital expenditures related to electric transmission operations in TO rate cases. (See "Regulatory Matters" below.)

The CPUC authorizes most of the Utility's revenue requirements to recover forecasted capital expenditures in multi-year GRCs and gas transmission and storage rate cases. In addition, from time to time, the CPUC authorizes the Utility to collect additional revenue requirements to recover capital expenditures related to specific projects that the CPUC has approved. For example, in 2009 the Utility incurred capital costs of approximately $490 million to install advanced meters and approximately $350 million for new generation facilities that are expected to become operational in 2010. As discussed below, the Utility has requested CPUC approval for other capital projects, such as the Utility's proposal to implement a distribution reliability improvement program and to develop new generation facilities. The FERC authorizes revenue requirements to recover forecasted capital expenditures related to electric transmission operations in TO rate cases. (See "Regulatory Matters" below.)

The Utility's ability to invest in its electric and natural gas systems and develop new generation facilities is subject to many risks, including risks related to securing adequate and reasonably priced financing, obtaining and complying with terms of permits, meeting construction budgets and schedules, and satisfying operating and environmental performance standards. (See "Risk Factors" below.)

PROPOSED ELECTRIC DISTRIBUTION RELIABILITY PROGRAM (CORNERSTONE IMPROVEMENT PROGRAM)

The Utility has requested that the CPUC approve a proposed electric distribution reliability improvement program, including initiatives designed to decrease the frequency and duration of electricity outages in order to bring the Utility's reliability performance closer to that of other investor-owned electric utilities and provide other reliability benefits. The Utility forecasts that it would incur approximately $2 billion of capital expenditures and $59 million of operating and maintenance expenses to implement the program. The Utility has requested that the CPUC authorize the Utility to recover these forecast costs beginning in 2011 and continuing through 2016. The CPUC's hearings to determine whether major capital expenditures are necessary to maintain or improve distribution reliability and, if necessary, to determine the extent and timing of such expenditures, were concluded in August 2009.

It is anticipated that the CPUC will issue a final decision during the second quarter of 2010.

PROPOSED NEW GENERATION FACILITIES

The Utility's CPUC-approved long-term electricity procurement plan, covering 2007 through 2016, forecasts that the Utility will need to obtain an additional 800 to 1,200 megawatts ("MW") of new generation resources by 2015 above the Utility's planned additions of renewable resources, energy efficiency, demand reduction programs, and previously approved contracts for new generation resources. Due to the cancellation of two projects selected in its 2004 request for offers ("RFOs") for new long-term generation resources, the Utility was authorized to increase the new generation resource need to obtain 1,112 to 1,512 MW. The CPUC allows the California investor-owned utilities to acquire ownership of new conventional generation resources only through purchase and sale agreements ("PSAs") (i.e., a PSA is a "turnkey" arrangement in which a new generating facility is constructed by a third party and then sold to the Utility upon satisfaction of certain contractual requirements). The utilities are prohibited from submitting offers for utility-built generation in their respective RFOs until questions can be resolved about how to compare utility-owned generation offers with offers from independent power producers. The utilities are permitted to propose utility-owned generation projects through a separate application outside of the RFO process in the following circumstances: (1) to mitigate market power demonstrated by the utility to be held by others, (2) to support a use of preferred resources (such as renewable energy sources), (3) to take advantage of a unique and fleeting opportunity (such as a bankruptcy settlement), and (4) to meet unique reliability needs.

On September 30, 2009, the Utility requested that the CPUC approve several agreements executed by the Utility following the completion of its April 1, 2008 RFOs of new long-term generation resources to meet customer demand as forecasted in the Utility's 2007–2016 long-term electricity procurement plan previously approved by the CPUC. One of the agreements submitted to the CPUC proposes that a 586 MW natural gas-fired facility be developed and constructed by a third party and then transferred to the Utility after commercial operation begins. The proposed facility would be operationally flexible, enabling the Utility to increase its use of renewable power by balancing the fluctuating output of wind and solar resources. The facility is proposed to be built in Oakley, California and completed in 2014. (The remaining agreements submitted to the CPUC are power purchase agreements.)

PROPOSED RENEWABLE ENERGY DEVELOPMENT

In February 2009, the Utility applied to the CPUC for approval of the Utility's proposed five-year program to develop up to 500 MW of renewable generation resources based on solar photovoltaic ("PV") technology. The program would include the development of 250 MW of utility-owned PV facilities at an estimated capital cost of approximately $1.5 billion. The Utility also proposed to enter into power purchase agreements for the remaining 250 MW of PV generation to be developed by independent power producers. On January 26, 2010, a proposed decision was issued recommending that the Utility be authorized to build up to 50 MW of PV facilities per year for each of the five years of the program and that the Utility be allowed to recover project costs based on the weighted average price of the winning bids received in response to the Utility's RFO for power purchase agreements under the program, subject to an overall price cap. If adopted by the CPUC, the Utility would be unable to include the new utility-owned PV facilities in rate base. Instead of earning an ROE, the Utility's revenue requirement for recovery of the cost of developing any utility-owned facilities would depend on the amount of power produced by the utility-owned PV facilities and the applicable weighted average price of winning bids received in response to annual program RFOs. The Utility would not be required to build any of the authorized utility-owned capacity under the proposed decision, but rather would elect annually whether to build utility-owned facilities after the applicable weighted average winning bid price had been determined. An alternate proposed decision that also was issued on January 26, 2010 contains similar recommendations. The Utility continues to believe that traditional rate-base treatment would be appropriate. The CPUC is expected to issue a final decision during the first quarter of 2010.

Additionally, on December 3, 2009, the Utility filed an application with the CPUC requesting approval to acquire and operate a wind project to be developed and constructed by Iberdrola Renewables, Inc. in Southern California. The proposed project would have a capacity of up to 246 MW with a guaranteed minimum capacity of 189 MW. The final size of the project would depend upon permitting requirements, completion of land rights acquisition, and turbine supply. Assuming the project is built to its full capacity of 246 MW, the Utility estimates it would incur capital costs of approximately $900 million. The project is targeted to become operational as early as December 2011. A CPUC decision is expected by the end of 2010.

OFF-BALANCE SHEET ARRANGEMENTS

PG&E Corporation and the Utility do not have any off-balance sheet arrangements that have had, or are reasonably likely to have, a current or future material effect on their financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures, or capital resources.

REGULATORY MATTERS

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

2011 GENERAL RATE CASE APPLICATION

In the Utility's last GRC, the CPUC authorized the Utility's revenue requirements for 2007 through 2010 for its basic business and operational costs related to its electric and natural gas distribution and electric generation operations. On December 21, 2009, the Utility filed its 2011 GRC application. The Utility is requesting that the CPUC authorize the amount of base revenues that the Utility may collect from customers to recover its costs for electric and natural gas distribution operations and electric generation operations for a three-year period (2011 through 2013). The Utility's request represents a proposed revenue increase for 2011 of $1.1 billion, or 6.4%, above the 2010 total revenue forecast. The critical driver of the Utility's request in this 2011 GRC will be the need to invest in energy infrastructure to meet customers' expectations for service quality. The Utility estimates that it will need to spend an average of about $2.7 billion in capital expenditures annually on these infrastructure improvements, especially replacement of gas and electric systems that are reaching the end of their useful lives. The Utility also needs adequate funds to continue to safely operate, maintain, and upgrade generation plants to serve growing demand.

The Utility also has proposed that the CPUC establish balancing accounts for several categories of costs that are subject to a high degree of volatility based on economic conditions and other factors, including new customer connections, emergency service restoration, uncollectible accounts, and employee health care costs.

The Utility also has requested that the CPUC establish a ratemaking mechanism for 2012 and 2013 designed to increase the Utility's authorized revenues in years between GRCs to reflect increases in rate base due to capital investments in infrastructure and increases in wages and expenses. The proposed mechanism also would require revenue requirements to be adjusted to reflect changes in franchise, payroll, income, or property tax rates, as well as new taxes or fees imposed by governmental agencies. The Utility estimates that this mechanism would result in a revenue requirement increase of $275 million in 2012 and an additional increase of $343 million in 2013. The Utility will advise the CPUC of the actual amount of these proposed increases in October 2011 and October 2012 for the years 2012 and 2013, respectively.

The Utility requested that the CPUC issue a final decision by the end of 2010. If the decision is delayed, the Utility will, consistent with CPUC practice in prior GRCs, request the CPUC to issue an order directing that the authorized revenue requirement changes be effective January 1, 2011, even if the decision is issued subsequent to that date.

PG&E Corporation and the Utility are unable to predict what amount of revenue requirements the CPUC will authorize for the period from 2011 through 2013, when a final decision in this proceeding will be received, or how the final decision will impact their financial condition or results of operations.

2011 GAS TRANSMISSION AND STORAGE RATE CASE

On September 18, 2009, the Utility filed an application with the CPUC to initiate the Utility's 2011 Gas Transmission and Storage rate case so that the CPUC can determine the rates and terms and conditions of the Utility's gas transmission and storage services beginning January 1, 2011. The rates and terms and conditions of the Utility's gas transmission and storage services for 2008 through 2010 were set by the terms of a CPUC-approved all-party settlement agreement known as the Gas Accord IV that was approved by the CPUC in September 2007. The Utility proposes to continue a majority of the Gas Accord IV's terms and conditions of natural gas transportation and storage services.

The Utility has requested that the CPUC approve a 2011 natural gas transmission and storage revenue requirement of $529.1 million, an increase of $67.3 million over the 2010 adopted revenue requirement. The Utility also seeks attrition increases for 2012, 2013, and 2014 of $32.4 million, $30.7 million, and $22.6 million, respectively.

Under the Utility's proposal, a substantial portion of the authorized revenue requirements – primarily those costs allocated to residential and small commercial customers (called "core" customers) – would continue to be assured of recovery through balancing account mechanisms and/or fixed reservation charges. The Utility has proposed to simplify the current rate structure by, among other changes, setting rates for core and non-core customers based on forecast demand. The Utility's ability to recover its remaining revenue requirements would continue to depend on throughput volumes, gas prices, and the extent to which non-core customers and other shippers contract for firm transmission services. To reduce the Utility's financial risk associated with these factors, the Utility has proposed to share equally with customers any under-collection or over-collection of natural gas transmission and storage revenue requirements. The Utility has proposed additional cost recovery mechanisms for costs that are difficult to forecast, such as the cost of electricity used to operate natural gas compressor stations and costs to comply with GHG regulations.

The Utility has requested that the CPUC issue a final decision by the end of 2010. If the CPUC does not issue a final decision by the end of 2010 to approve new rates effective January 1, 2011, the September 2007 CPUC decision approving the Gas Accord IV provides that the rates and terms and conditions of service in effect as of December 31, 2010 will remain in effect, with an automatic 2% escalation in rates, for local transmission only, as of January 1, 2011.

ELECTRIC TRANSMISSION OWNER RATE CASES

The Utility generally files a TO rate case every year to request that the FERC authorize the Utility to collect an annual retail transmission revenue requirement at rates based on the Utility's forecast of customer demand for the particular rate case year. The Utility's ability to recover the FERC-authorized revenue requirement is subject to the actual volume of electricity sales for the particular rate case year. The Utility is typically able to collect the proposed new rates based on the amount of the requested annual revenue requirement before the FERC issues a decision authorizing new rates. The rates collected before the FERC issues a decision are subject to refund to customers.

On June 18, 2009, the FERC approved a settlement that sets the Utility's annual retail transmission base revenue requirement at $776 million, effective March 1, 2009. As part of the settlement, the Utility will refund any over-collected amounts to customers, with interest, through an adjustment to rates in 2011.

On July 30, 2009, the Utility filed an application with the FERC requesting an annual retail transmission revenue requirement of $946 million. The proposed rates represent an increase of $170 million over current authorized revenue requirements. On September 30, 2009, the FERC accepted the Utility's application making the proposed rates effective March 1, 2010 subject to refund following the conclusion of hearings and the outcome of judge-supervised settlement discussions.

ENERGY EFFICIENCY PROGRAMS AND INCENTIVE RATEMAKING

The CPUC established a ratemaking mechanism to provide incentives to the California investor-owned utilities to meet the CPUC's energy savings goals through implementation of the utilities' energy efficiency programs. As originally established, this mechanism was intended to apply to the 2006 through 2008 and 2009 through 2011 program cycles. In January 2009, the CPUC established a new rulemaking proceeding to modify the mechanism for energy efficiency programs in 2009 and future years. It is uncertain what modifications will ultimately be adopted by the CPUC.

On December 17, 2009, in accordance with the existing mechanism, the CPUC awarded the Utility incentive revenues of $33.4 million based on the energy savings achieved through implementation of the Utility's energy efficiency programs during the 2006 through 2008 program cycle. (This amount is in addition to incentive revenues of $41.5 million awarded by the CPUC to the Utility in December 2008 based on the Utility's 2006 through 2007 program performance.) Consistent with the incentive award process previously adopted by the CPUC, the CPUC held back an additional $40.3 million of incentive revenues. The additional amount of incentive revenues that the Utility could receive, if any, will be determined after final energy savings for the 2006 through 2008 program cycle are verified and the true-up process is completed in 2010. The CPUC adopted a schedule for the final true-up process that calls for a final decision by the end of 2010.

With respect to the utilities' 2009 through 2011 energy efficiency programs, the CPUC issued a decision on September 24, 2009 that changed the program cycle to cover 2010 through 2012. The CPUC also authorized the Utility to continue to collect the bridge funding for its 2009 programs and authorized the Utility to collect $1.3 billion to fund its 2010 through 2012 programs, a 42% increase over the amount authorized for the 2006 through 2008 programs. The CPUC has not yet determined how the existing incentive mechanisms will be modified. Therefore, the amount of incentive revenues the Utility may earn for implementation of its energy efficiency programs in 2009 and future years, if any, is uncertain.

DIABLO CANYON RELICENSING APPLICATION

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. NRC regulations require extensive monitoring and review of the safety, radiological, environmental, and security aspects of these facilities. 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. On November 24, 2009, the Utility filed an application to request the NRC to renew each of the operating licenses for Diablo Canyon for 20 years, until November 2044 for Unit 1 and August 2045 for Unit 2, citing a critical need in California for the long-term supply of clean, affordable, and reliable electricity. The license renewal process is expected to take several years as the NRC holds public hearings and conducts safety and environmental analyses and site audits. On January 29, 2010, the Utility requested that the CPUC authorize the Utility to recover in rates the costs of seeking license renewal. The Utility currently estimates that it will incur $85 million through 2014 in connection with the relicensing process.

ENVIRONMENTAL MATTERS

The Utility's operations are subject to extensive federal, state, and local laws and permits relating to the protection of the environment and the safety and health of the Utility's personnel and the public. (See "Risk Factors" below.) These laws and requirements relate to a broad range of the Utility's activities, including the discharge of pollutants into the air, water, and soil; the transportation, handling, storage, and disposal of spent nuclear fuel; remediation of hazardous wastes; and the reporting and reduction of carbon dioxide and other GHG emissions.

CLIMATE CHANGE

PG&E Corporation and the Utility believe the link between man-made GHG emissions and global climate change is clear and convincing and that mandatory GHG reductions are necessary. PG&E Corporation and the Utility believe the development of a market-based cap-and-trade system, in conjunction with successful energy efficiency and demand-side management programs and the development of renewable energy resources, can reduce GHG emissions while diversifying energy supply resources and minimizing costs to customers. Various laws and regulations addressing climate change and GHG emissions are being considered at the state, federal, and regional levels. Several contentious issues must be resolved before a state, regional, or national cap-and-trade program for emission allowances can be established, including determining whether emission allowances should be auctioned or freely allocated to the utilities to reduce customer costs, whether price caps or collars should be established for emission allowances, the use of emission offsets, and how any auction revenues or other value should be used.

The California Global Warming Solutions Act of 2006 ("AB 32") requires the gradual reduction of GHG emissions in California to 1990 levels by 2020 on a schedule beginning in 2012. The California Air Resources Board ("CARB") has been authorized to monitor and enforce compliance with AB 32. In December 2008, the CARB adopted a scoping plan that contains recommendations for achieving the maximum technologically feasible and cost-effective GHG reductions to meet the 2020 reduction target. These recommendations include implementing a 33% renewable portfolio standard ("RPS") by 2020, increasing energy efficiency goals, expanding the use of combined heat and power facilities, and developing a multi-sector cap-and-trade program. The CARB is required to adopt regulations to implement the scoping plan no later than January 1, 2011 to become effective on January 1, 2012.

In November 2009, the CARB issued preliminary draft regulations to establish a cap-and-trade program that would set a declining ceiling on GHG emissions and allow companies to buy and sell emission allowances or offsets to meet it. For the electric sector, the CARB proposes to assign responsibility to acquire emission allowances or offsets to the generator for in-state power and to the entity that holds title to the electricity for imports into California. For the natural gas sector, the CARB will consider assigning responsibility to acquire emission allowances or offsets to the local gas distribution company with respect to the emissions of small commercial and residential natural gas consumers beginning in 2012 instead of 2015 as the CARB had originally contemplated. The owners of natural gas compressor stations would also be responsible for compliance. Although the CARB has not yet addressed the allocation of emission allowances, in December 2009, an advisory committee to the CARB, the Economic and Allocation Advisory Committee ("EAAC"), recommended that the utilities be required to pay for emission allowances rather than receive all or a portion of such allowances for free. The Utility estimates that its additional compliance costs to acquire emission allowances to meet its compliance obligations and procure electricity at market prices that reflect the supplier's cost of emission allowances, could total approximately $1 billion per year beginning in 2012. This estimate assumes a market price for emissions allowances of $30 per metric tonne and that the Utility is not freely allocated some or all of its emission allowances to reduce customer costs as recommended by the EAAC. This estimate is based on the Utility's forecasts of customer demand and levels of Utility-owned nuclear and hydroelectric generation and assumes average weather conditions. The Utility expects that these increased costs would be included in the Utility's cost of electricity that is passed through to customers or be recovered in rates as reasonable costs of complying with environmental regulations and mandates. The CARB is scheduled to issue final regulations in October 2010. The ultimate financial impact of a cap-and-trade system will depend on the final form of regulations adopted by the CARB, the actual market price of emissions allowances, and the resolution of the issues discussed above.

While proposed legislation is being considered at the federal level, the Environmental Protection Agency ("EPA"), charged with implementation and enforcement of the Clean Air Act, released a final ruling in December 2009, finding that GHG emissions cause or contribute to air pollution that endangers public health and welfare. It is expected that the EPA will adopt regulations to establish new thresholds for GHG emissions from vehicles and that the EPA will propose regulations that would apply to new or existing industrial facilities, power plants, and other stationary sources. At the regional level, the Western Climate Initiative ("WCI"), comprising seven states – including California – and four Canadian provinces, has proposed to establish a regional cap-and-trade program to reduce GHG emissions beginning in 2012. California has indicated that it seeks to participate in the WCI, but it has also indicated that it will proceed with AB 32 implementation regardless of whether the WCI cap-and-trade program is implemented.

The Utility has voluntarily reported its GHG emissions to the California Climate Action Registry ("CCAR") on an annual basis since 2002. In 2009, the Utility also voluntarily reported its 2008 GHG emissions to The Climate Registry ("TCR"), a new non-profit organization that is developing consistent reporting and measurement standards across industry sectors in North America. In 2009, the Utility also began reporting its GHG emissions to the CARB as required by AB 32. The EPA also has adopted regulations that require qualifying GHG-emitting facilities to submit annual GHG emissions reports beginning in 2011. PG&E Corporation and the Utility provide detailed GHG emissions data in their annual Corporate Responsibility Report, available on their websites. As a result of the time necessary for a thorough third-party verification of the Utility's GHG emissions in accordance with the highest standards developed by the CCAR and TCR, preliminary emissions data for 2008 is the most recent data available. Preliminary emissions data for 2008 is also contained in PG&E Corporation's and the Utility's Annual Report on Form 10-K for the year ended December 31, 2009.

During 2009, the Utility continued its programs to develop strategies to mitigate the impact of the Utility's operations on the environment (including customer energy usage) and to develop its strategy to plan for the actions it will need to take to adapt to likely impacts that climate change will have on the Utility's future operations. With respect to electric operations, climate scientists project that climate change will lead to increased electricity demand due to more extreme and frequent hot weather events and reduced hydroelectric generation due to reductions in snowpack in the Sierra Nevada. The Utility is analyzing and exploring a combination of operating changes to its hydroelectric system that may include, but are not limited to, higher winter carryover reservoir storage levels, reduced conveyance flows in canals and flumes during winter storm periods, reduced discretionary reservoir releases during the late spring and summer period, and increased sediment releases from diversion dams. If the Utility's future hydroelectric generation is reduced due to drought conditions or climate change, the Utility might have to replace some of this electricity from other sources, including natural gas. The amount of fossil-fueled generation needed to replace decreased hydroelectric generation can be reduced if renewable resources, such as geothermal and biomass, are timely developed. (See "Capital Expenditures" above for a description of the Utility's efforts to invest in renewable resources.)

With respect to natural gas operations, the Utility has taken voluntary proactive steps to reduce the release of methane, a GHG released as part of the delivery of natural gas.

The Utility's strategies to reduce GHG emissions – such as offering energy efficiency and demand response programs for customers, infrastructure improvements, and the support of renewable energy development – are also effective strategies for adapting to the expected increased demand for electricity in extreme hot weather events likely to be caused by climate change. PG&E Corporation and the Utility are also assessing the benefits and challenges associated with various climate change policies, identifying how a comprehensive program can be structured to mitigate overall costs to customers and the economy as a whole, as well as to ensure that the environmental objectives of the program are met.

WATER QUALITY

In addition, there is continuing uncertainty about the status of state and federal regulations issued under Section 316(b) of the Clean Water Act, which require that cooling water intake structures at electric power plants, such as the nuclear generation facilities at Diablo Canyon, reflect the best technology available to minimize adverse environmental impacts. Depending on the form of the final regulations that may ultimately be adopted by the EPA or the California Water Resources Control Board ("Water Board"), the Utility may incur significant capital expense to comply with the final regulations, which the Utility would seek to recover through rates. If either of the final regulations adopted by the EPA or the Water Board requires the installation of cooling towers at Diablo Canyon, and if installation of such cooling towers is not technically or economically feasible, the Utility may be forced to cease operations at Diablo Canyon and may incur a material charge. (See Note 16 of the Notes to the Consolidated Financial Statements for more information.)

REMEDIATION

The Utility may be required to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party under environmental laws. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances at former manufactured gas plant ("MGP") sites; power plant sites; and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous materials, even if the Utility did not deposit those substances on the site. In particular, the Utility has a program, in cooperation with environmental agencies and third-party owners, to evaluate and take appropriate action to mitigate any potential environmental concerns posed by certain former MGP sites within the Utility's service territory. As part of this program, the Utility recently contacted the owners of property located on three former MGP sites in urban, residential areas of San Francisco to offer to test the soil for residues, and depending on the results of such tests, to take appropriate remedial action. Until the Utility's investigation of these MGP sites in San Francisco is complete, the extent of the Utility's obligation to remediate is established, and any appropriate remedial actions are determined, the Utility is unable to determine the amounts it may spend in the future to remediate these sites and no amounts have been accrued for these sites (other than investigative costs). Although it is reasonably possible that the Utility will incur losses in the future related to these sites, the Utility is unable to reasonably estimate the amount of such loss. The Utility expects that it will recover 90% of the costs to remediate MGP sites under a ratemaking mechanism established by the CPUC. The Utility will seek to recover remaining costs through insurance. (See "Risk Factors" and "Critical Accounting Policies" below, as well as Note 16 of the Notes to the Consolidated Financial Statements, for a discussion of estimated environmental remediation liabilities.)

LEGAL MATTERS

PG&E Corporation and the Utility are subject to various laws and regulations and, in the normal course of business, PG&E Corporation and the Utility are named as parties in a number of claims and lawsuits. (See Note 16 of the Notes to the Consolidated Financial Statements for a discussion of the accrued liability for legal matters.)

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; their financing arrangements; the marketplace for electricity, natural gas, electricity transmission, natural gas transportation, and storage; other goods and services; and other aspects of their businesses. PG&E Corporation and the Utility categorize market risks as "price risk" and "interest rate risk." The Utility is also exposed to "credit risk," the risk that counterparties fail to perform their contractual obligations.

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.

PRICE RISK

The Utility is exposed to commodity price risk as a result of its electricity procurement activities, including the procurement of natural gas and nuclear fuel necessary for electricity generation and natural gas procurement for core customers. As long as the Utility can conclude that it is probable that its reasonably incurred wholesale electricity procurement costs and natural gas costs are recoverable, fluctuations in electricity and natural gas prices will not affect earnings but may impact cash flows. The Utility's natural gas transportation and storage costs for core customers are also fully recoverable through a ratemaking mechanism.

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.

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

The Utility's value-at-risk calculated under the methodology described above was approximately $12 million at December 31, 2009. The Utility's high, low, and average values-at-risk during the 12 months ended December 31, 2009 were approximately $17 million, $9 million, and $14 million, respectively.

See Note 10 of the Notes to the Consolidated Financial Statements for further discussion of price risk management activities.

INTEREST RATE RISK

Interest rate risk sensitivity analysis is used to measure interest rate risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. At December 31, 2009, if interest rates changed by 1% for all current PG&E Corporation and the Utility variable rate and short-term debt and investments, the change would have an immaterial impact to net income over the next 12 months.

CREDIT RISK

The Utility conducts business with counterparties mainly in the energy industry, including other California investor-owned electric utilities, municipal utilities, energy trading companies, financial institutions, and oil and natural gas production companies located in the United States and Canada. If a counterparty failed to perform on its contractual obligation to deliver electricity or gas, then the Utility may find it necessary to procure electricity or gas at current market prices, which may be higher than the contract prices.

The Utility manages credit risk associated with its counterparties by assigning credit limits based on evaluations of their financial conditions, net worth, credit ratings, and other credit criteria as deemed appropriate. Credit limits and credit quality are monitored periodically. The Utility ties many energy contracts to master commodity enabling agreements that may require security (referred to as "Credit Collateral" in the table below). Credit Collateral may be in the form of cash or letters of credit. The Utility may accept other forms of performance assurance in the form of corporate guarantees of acceptable credit quality or other eligible securities (as deemed appropriate by the Utility). Credit Collateral or performance assurance may be required from counterparties when current net receivables and replacement cost exposure exceed contractually specified limits.

The following table summarizes the Utility's net credit risk exposure to its counterparties, as well as the Utility's credit risk exposure to counterparties accounting for greater than 10% net credit exposure, as of December 31, 2009 and 2008:

(in millions)	Gross Credit Exposure Before Credit Collateral(1)	Credit Collateral	Net Credit Exposure(2)	Number of Wholesale Customers or Counterparties >10%	Net Exposure to Wholesale Customers or Counterparties >10%
December 31, 2009	**$202**	**$24**	**$178**	**3**	**$154**
December 31, 2008	$240	$84	$156	2	$107

(1) Gross credit exposure equals mark-to-market value on physically and financially settled contracts, notes receivable, and net receivables (payables) where netting is contractually allowed. Gross and net credit exposure amounts reported above do not include adjustments for time value or liquidity.

(2) Net credit exposure is the Gross Credit Exposure Before Credit Collateral minus Credit Collateral (cash deposits and letters of credit). For purposes of this table, parental guarantees are not included as part of the calculation.

CRITICAL ACCOUNTING POLICIES

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

The Utility's rates are primarily set by the CPUC and the FERC and are designed to recover the cost of providing service. The Utility capitalizes and records, as a regulatory asset, costs that would otherwise be charged to expense if it is probable that the incurred costs will be recovered in future rates. The regulatory assets are amortized over future periods when the costs are expected to be recovered. If costs expected to be incurred in the future are currently being recovered through rates, the Utility records those expected future costs as regulatory liabilities. In addition, amounts that are probable of being credited or refunded to customers in the future are recorded as regulatory liabilities.

Determining probability requires significant judgment on the part of management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders, and the strength or status of applications for rehearing or state court appeals. For some of the Utility's regulatory assets, including the regulatory assets for ERBs and utility retained generation, the Utility has determined that the costs are recoverable based on specific approval from the CPUC. The Utility also records a regulatory asset when a mechanism is in place to recover current expenditures and historical experience indicates that recovery of incurred costs is probable, such as the regulatory assets for pension benefits; deferred income tax; price risk management; and unamortized loss, net of gain, on reacquired debt. The CPUC has not denied the recovery of any material costs previously recognized by the Utility as a regulatory asset during the periods ended December 31, 2009, 2008, or 2007.

The Utility records regulatory liabilities when the CPUC or the FERC requires a refund to be made to customers, authorizes the collection of rates intended to recover costs that are expected to be incurred in the future, or a regulator has required that a gain or other reduction of net allowable costs be given to customers over future periods.

If the Utility determined that it is no longer probable that revenues or costs would be recovered or reflected in future rates, or if the Utility ceased to be subject to rate regulation, the revenues or costs would be charged to income in the period in which they were incurred. At December 31, 2009, PG&E Corporation and the Utility reported regulatory assets (including current regulatory balancing accounts receivable) of $6.6 billion and regulatory liabilities (including current balancing accounts payable) of $4.4 billion.

ENVIRONMENTAL REMEDIATION LIABILITIES

The Utility is subject to loss contingencies pursuant to federal and California environmental laws and regulations that in the future may require the Utility to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party. Such contingencies may exist for the remediation of hazardous substances at various potential sites, including, but not limited to, former MGP sites, power plant sites, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous materials, even if the Utility did not deposit those substances on the site.

The Utility generally commences the environmental remediation assessment process upon notification from federal or state agencies, or other parties, of a potential site requiring remedial action. (In some instances, the Utility may voluntarily initiate action to determine its remediation liability for sites that it no longer owns in cooperation with regulatory agencies. For example, the Utility has begun a voluntary program related to certain former MGP sites.) Based on such notification, the Utility completes an assessment of the potential site and evaluates whether it is probable that a remediation liability has been incurred. The Utility records an environmental remediation liability when site assessments indicate remediation is probable and it can reasonably estimate the loss within a range of possible amounts. Given the complexities of the legal and regulatory environment and the inherent uncertainties involved in the early stages of a remediation project, the process for estimating remediation liabilities is subjective and requires significant judgment. Key factors evaluated in developing cost estimates include the extent and types of hazardous substances at a potential site, the range of technologies that can be used for remediation, the determination of the Utility's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties.

When possible, the Utility estimates costs using site-specific information, but also considers historical experience for costs incurred at similar sites depending on the level of information available. Estimated costs are composed of the direct costs of the remediation effort and the costs of compensation for employees who are expected to devote a significant amount of time directly to the remediation effort. These estimated costs include remedial site investigations, remediation actions, operations and maintenance activities, post remediation monitoring, and the costs of technologies that are expected to be approved to remediate the site. Remediation efforts for a particular site generally extend over a period of several years. During this period, the laws governing the remediation process may change, thereby possibly affecting the cost of the remediation effort.

The Utility evaluates the possible range of estimated costs and records an environmental remediation liability based on the lower end of the range of estimated costs, unless a more objective estimate can be achieved. Amounts recorded are not discounted to their present value. When the Utility is one of several potentially responsible parties, the Utility records the liability based on its estimates of its allocable share of the remediation liability. The recorded liabilities are re-examined every quarter, and adjustments are made based on changes in facts and circumstances or as additional information becomes available.

At December 31, 2009 and 2008, the Utility's accruals for undiscounted and gross environmental liabilities were $586 million and $568 million, respectively. The Utility's undiscounted future costs could increase to as much as $1 billion if other potentially responsible parties are not able to contribute to these costs or if the extent of contamination or necessary remediation is greater than anticipated, and could increase further if the Utility chooses to remediate beyond regulatory requirements. Although the Utility has accrued for known environmental obligations that are probable and reasonably estimable, estimated costs may vary significantly from actual costs, and the amount of additional future costs may be material to results of operations in the period in which they are recognized.

ASSET RETIREMENT OBLIGATIONS

The Utility accounts for an asset retirement obligation ("ARO") at fair value in the period during which the Utility incurs the legal obligation if a reasonable estimate of fair value and its settlement date can be made. A legal obligation can arise from an existing or enacted law, statute, or ordinance; a written or oral contract; or under the legal doctrine of promissory estoppel.

At the time of recording an ARO, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. The Utility recognizes a regulatory asset or liability for the timing differences between the recognition of costs as recorded in accordance with GAAP and costs recovered through the ratemaking process.

The fair value of an ARO is dependent upon the following factors:

- **Decommissioning costs:** The estimated costs for labor, equipment, material, and other disposal costs based on the decommissioning studies;
- **Inflation adjustment:** The estimated cash flows are adjusted for inflation estimates based on the component of cost;
- **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;
- **Third-party mark-up adjustments:** Internal labor costs included in the cash flow calculation are adjusted for costs that a third party would incur in performing the tasks necessary to retire the asset; and
- **Estimated date of decommissioning:** The fair value of the obligation will change based on the expected date of decommissioning.

Changes in these factors could materially affect the obligation recorded to reflect the ultimate cost associated with retiring the assets. For example, a premature shutdown of the nuclear facilities at Diablo Canyon would increase the likelihood of an earlier start to decommissioning and cause an increase in the obligation. (See Note 12 of the Notes to the Consolidated Financial Statements.) Additionally, if the inflation adjustment increased 25 basis points, this would increase the amount of an ARO by approximately 1.30%. Similarly, an increase in the discount rate by 25 basis points would decrease the amount of an ARO by 0.90%. At December 31, 2009, the Utility's estimated cost of retiring these assets is $1.6 billion.

ACCOUNTING FOR INCOME TAXES

PG&E Corporation's and the Utility's accounting for taxes requires judgment regarding the potential tax effects of ongoing operations and uncertain tax positions to determine obligations owed to tax authorities. (See Note 9 of the Notes to the Consolidated Financial Statements.) 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

Eligible employees and retirees of PG&E Corporation and its subsidiaries receive qualified and non-qualified non-contributory defined benefit pension plans. Retired employees and their eligible dependents of PG&E Corporation and its subsidiaries receive 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 are based on a variety of factors, including the provisions of the plans, employee demographics and various actuarial calculations, assumptions, and accounting mechanisms.

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 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 that 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.

Changes in benefit obligations associated with these assumptions may not be recognized as costs on the statement of income. Differences between actuarial assumptions and actual plan results are deferred in Accumulated other comprehensive income (loss) 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, 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 $458 million in 2009, $169 million in 2008, and $117 million in 2007. PG&E Corporation and the Utility recorded expense for other postretirement benefits totaled $94 million in 2009, $44 million in 2008, and $44 million in 2007.

PG&E Corporation and the Utility recognize the funded status of their respective plans on their respective Consolidated Balance Sheet with an offsetting entry to Accumulated other comprehensive income (loss), resulting in no impact to their respective Consolidated Statements of Income.

Since 1993, the CPUC has authorized the Utility to recover the costs associated with its other postretirement benefits based on the annual tax-deductible contributions to the appropriate trusts. Regulatory adjustments have been recorded in the Consolidated Statements of Income and the Consolidated Balance Sheets of the Utility to reflect the difference between Utility pension expense or income for accounting purposes and Utility pension expense or income for ratemaking, which is based on a funding approach.

The differences between pension benefit costs recognized in accordance with GAAP and amounts recognized for ratemaking purposes are recorded as a regulatory asset or liability as amounts are probable of recovery from customers. (See Note 3 of the Notes to the Consolidated Financial Statements.) Therefore, the difference is not expected to impact net income in future periods.

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, the Utility has not identified any minimum funding requirements related to its pension plans.

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, absolute return securities, and fixed income securities. Investment securities are exposed to various risks, including interest rate risk, credit risk, 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's defined benefit pension plan, the assumed return of 6.8% compares to a 10-year actual return of 4.7%.

The rate used to discount pension and other postretirement benefit plan liabilities was based on a yield curve developed from market data of approximately 300 Aa-grade non-callable bonds at December 31, 2009. 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 2009 Pension Costs	Increase in Projected Benefit Obligation at December 31, 2009
Discount rate	(0.5)%	$70	$746
Rate of return on plan assets	(0.5)%	40	–
Rate of increase in compensation	0.5%	32	176

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 2009 Other Postretirement Benefit Costs	Increase in Accumulated Benefit Obligation at December 31, 2009
Health care cost trend rate	0.5%	$6	$39
Discount rate	(0.5)%	6	84
Rate of return on plan assets	(0.5)%	5	–

ACCOUNTING PRONOUNCEMENTS ISSUED BUT NOT YET ADOPTED

TRANSFERS AND SERVICING (TOPIC 860) — ACCOUNTING FOR TRANSFERS OF FINANCIAL ASSETS

In December 2009, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2009-16, "Transfers and Servicing (Topic 860) – Accounting for Transfers of Financial Assets" ("ASU No. 2009-16"). ASU No. 2009-16 eliminates the concept of a qualifying special-purpose entity and clarifies the requirements for derecognizing a financial asset and for applying sale accounting to a transfer of a financial asset. In addition, ASU No. 2009-16 requires an entity to disclose more information about transfers of financial assets; the entity's continuing involvement, if any, with transferred financial assets; and the entity's continuing risks, if any, from transferred financial assets. ASU No. 2009-16 is effective prospectively for PG&E Corporation and the Utility beginning on January 1, 2010. PG&E Corporation and the Utility are currently evaluating the impact of ASU No. 2009-16.

CONSOLIDATIONS (TOPIC 810) — IMPROVEMENTS TO FINANCIAL REPORTING BY ENTERPRISES INVOLVED WITH VARIABLE INTEREST ENTITIES

In December 2009, the FASB issued ASU No. 2009-17, "Consolidations (Topic 810) – Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities" ("ASU No. 2009-17"). ASU No. 2009-17 amends the Consolidation Topic of the FASB Accounting Standards Codification ("ASC") regarding when and how to determine, or re-determine, whether an entity is a variable interest entity ("VIE"). In addition, ASU No. 2009-17 replaces the Consolidation Topic of the FASB ASC's quantitative approach for determining who has a controlling financial interest in a VIE with a qualitative approach. Furthermore, ASU No. 2009-17 requires ongoing assessments of whether an entity is the primary beneficiary of a VIE. ASU No. 2009-17 is effective prospectively for PG&E Corporation and the Utility beginning on January 1, 2010. PG&E Corporation and the Utility are currently evaluating the impact of ASU No. 2009-17.

RISK FACTORS

RISKS RELATED TO PG&E CORPORATION

As a holding company, PG&E Corporation depends on cash distributions and reimbursements from the Utility to meet its debt service and other financial obligations and to pay dividends on its common stock.

PG&E Corporation is a holding company with no revenue generating operations of its own. PG&E Corporation's ability to pay interest on its $247 million of Convertible Subordinated Notes and to pay dividends on its common stock, as well as satisfy its other financial obligations, primarily depends on the earnings and cash flows of the Utility and the ability of the Utility to distribute cash to PG&E Corporation (in the form of dividends and share repurchases) and reimburse PG&E Corporation for the Utility's share of applicable expenses. Before it can distribute cash to PG&E Corporation, the Utility must use its resources to satisfy its own obligations, including its obligation to serve customers, to pay principal and interest on outstanding debt, to pay preferred stock dividends, and meet its obligations to employees and creditors. If the Utility is not able to make distributions to PG&E Corporation or to reimburse PG&E Corporation, PG&E Corporation's ability to meet its own obligations could be impaired and its ability to pay dividends could be restricted.

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.

The CPUC imposed certain conditions when it approved the original formation of a holding company for the Utility, 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 adopting an expansive interpretation of PG&E Corporation's obligations under this condition, including the requirement that PG&E Corporation "infuse the Utility with all types of capital necessary for the Utility to fulfill its obligation to serve." The CPUC's interpretation of PG&E Corporation's obligation under the first priority condition could require PG&E Corporation to infuse the Utility with significant capital in the future or could prevent distributions from the Utility to PG&E Corporation, either of which could materially restrict PG&E Corporation's ability to pay or increase its common stock dividend, meet other obligations, or execute its business strategy.

RISKS RELATED TO PG&E CORPORATION AND THE UTILITY

PG&E Corporation's and the Utility's financial condition and results of operations will be affected by the terms of future debt and equity financings.

The Utility's ability to fund its operations, pay principal and interest on its debt, fund capital expenditures and provide collateral to support its natural gas and electricity procurement hedging contracts depends on the levels of its operating cash flow and access to the capital and credit markets. In addition, PG&E Corporation's ability to fund its operations, make capital expenditures, and contribute equity to the Utility as needed to maintain the Utility's CPUC-authorized equity ratio depends on the ability of the Utility to pay dividends to PG&E Corporation and PG&E Corporation's independent access to the capital and credit markets. PG&E Corporation may also be required to access the capital markets when the Utility is successful in selling long-term debt so that it may make the equity contributions required to maintain the Utility's applicable equity ratio.

If the Utility were unable to access the capital markets, it could be required to decrease or suspend dividends to PG&E Corporation. PG&E Corporation also would need to consider its alternatives, such as contributing capital to the Utility, to enable the Utility to fulfill its obligation to serve. If PG&E Corporation is required to contribute equity to the Utility in these circumstances, it would be required to secure these funds from the capital or credit markets.

PG&E Corporation's and the Utility's ability to access the capital and credit markets and the costs and terms of available financing depend on many factors, including changes in their credit ratings, changes in the federal or state regulatory environment affecting energy companies, the overall health of the energy industry, volatility in electricity or natural gas prices, and general economic and market conditions.

Market performance or changes in other assumptions could require PG&E Corporation and the Utility to make significant unplanned contributions to its pension plan, other postretirement benefits plans, and nuclear decommissioning trusts.

PG&E Corporation and the Utility provide defined benefit pension plans and other postretirement benefits for eligible employees and retirees. The Utility also maintains three trusts for the purposes of providing funds to decommission its nuclear facilities. Up to approximately 60% of the plan assets and trust assets have generally been invested in equity securities, which are subject to market fluctuation. A decline in the market value may increase the funding requirements for these plans and trusts.

The cost of providing pension and other postretirement benefits is also affected by other factors, including the assumed rate of return on plan assets, employee demographics, discount rates used in determining future benefit obligations, rates of increase in health care costs, levels of assumed interest rates, future government regulation, and prior contributions to the plans. Similarly, funding requirements for the nuclear decommissioning trusts are affected by changes in the laws or regulations regarding nuclear decommissioning or decommissioning funding requirements, changes in assumptions as to decommissioning dates, technology and costs of labor, materials and equipment change, and assumed rate of return on plan assets. For example, changes in interest rates affect the liabilities under the plans: as interest rates decrease, the liabilities increase, potentially increasing the funding requirements.

The Utility recovers forecasted costs to fund pension and postretirement plan contributions and nuclear decommissioning through rates. If the Utility is required to make significant unplanned contributions to fund the pension and postretirement plans and nuclear decommissioning trusts and is unable to recover such contributions in rates, the contributions would negatively affect PG&E Corporation's and the Utility's financial condition, cash flows, and results of operations.

Other Utility obligations, such as its workers' compensation obligations, are not separately earmarked for recovery through rates. Therefore, increases in the Utility's workers' compensation liabilities and other unfunded liabilities caused by a decrease in the applicable discount rate negatively impact net income.

The Utility's revenues, operating results, and financial condition may fluctuate with the economy and the economy's corresponding impact on the Utility's customers.
The Utility is impacted by the economic cycle of the customers it serves. The declining economy in the Utility's service territory and the declines in the values of residential real estate have resulted in lower customer demand and lower customer growth at the Utility, and an increase in unpaid customer accounts receivable. Increasing unemployment could further reduce demand as residential customers voluntarily reduce their consumption of electricity in response to decreases in their disposable income. A sustained downturn or sluggishness in the economy could reduce the Utility's sales to industrial and commercial customers. Although the Utility generally recovers its costs through rates, regardless of sales volume, rate pressures increase when the costs are borne by a smaller sales base.

The completion of capital investment projects is subject to substantial risks, and the rate at which the Utility invests and recovers capital will directly affect net income.
The Utility's ability to develop new generation facilities and to invest in its electric and gas systems is subject to many risks, including risks related to obtaining regulatory approval for capital investment projects, securing adequate and reasonably priced financing, obtaining and complying with the terms of permits, meeting construction budgets and schedules, and satisfying operating and environmental performance standards. Third-party contractors on which the Utility depends to develop these projects also face many of these risks. The development of proposed Utility-owned renewable energy projects may also be affected by the extent to which necessary electric transmission facilities are built and evolving federal and state policies regarding the development of a "smart" electric transmission grid. Changes in tax laws or policies, such as those relating to production and investment tax credits for renewable energy projects, may also affect when or whether the Utility develops a potential project. In addition, reduced forecasted demand for electricity and natural gas as a result of the slowing economy may also increase the risk that projects are deferred, abandoned, or cancelled.

In addition, the Utility may incur costs that it will not be permitted to recover from customers. The Utility's amount and timing of capital expenditures can be affected by changes in the economy that impact customer demand and the rate of new customer connections. If capital spending in a particular time period is greater than assumed when rates were set, earnings could be negatively affected by an increase in depreciation, taxes, and financing interest and the absence of authorized revenue requirements to recover an ROE on the amount of capital expenses that exceeds assumed amounts.

PG&E Corporation's investment in new natural gas pipeline projects is subject to similar risks and, in the case of the proposed Pacific Connector, is subject to the development of a proposed liquefied natural gas storage terminal by third parties. In addition, pipeline project development is conditioned on obtaining certain levels of capacity commitments from shippers. Many of these conditions must be satisfied by PG&E Corporation's investment partners.

PG&E Corporation's and the Utility's financial statements reflect various estimates, assumptions, and values; changes to these estimates, assumptions, and values — as well as the application of and changes in accounting rules, standards, policies, guidance, or interpretations — could materially affect PG&E Corporation's and the Utility's financial condition or results of operations.
The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of revenues, expenses, assets, and liabilities, and the disclosure of contingencies. (See the discussion under Note 1 of the Notes to the Consolidated Financial Statements and the section entitled "Critical Accounting Policies" in the MD&A.) If the information on which the estimates and assumptions are based prove to be incorrect or incomplete; if future events do not occur as anticipated; or if there are changes in applicable accounting guidance, policies, or interpretation, management's estimates and assumptions will change as appropriate. A change in management's estimates or assumptions, or the recognition of actual losses that differ from the amount of estimated losses, could have a material impact on PG&E Corporation's and the Utility's financial condition and results of operations. For example, if management can no longer assume that potentially responsible parties will pay a material share of the costs of environmental remediation or if PG&E Corporation or the Utility incurs losses in connection with environmental remediation; litigation; or other legal, administrative, or regulatory proceedings that materially exceed the provision it estimated for these liabilities, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flow would be materially adversely affected.

PG&E Corporation's and the Utility's financial 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'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, its operating expenses, and an adequate return of and on the capital invested in its utility assets, including the costs of long-term debt and equity issued to finance their acquisition. Unanticipated changes in operating expenses or capital expenditures can 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 Utility's revenue requirements for its basic electric and natural gas distribution operations and its electric generation operations have been set by the CPUC through 2010, and the Utility's next GRC will not be effective until January 1, 2011. In addition, the CPUC or the FERC may not allow the Utility to recover costs that it has already incurred on the basis that such costs were not reasonably or prudently incurred or for other reasons.

The CPUC also has authorized the Utility to collect rates to recover the costs of various public policy programs that provide customer incentives and subsidies for energy efficiency programs and for the development and use of renewable and self-generation technologies. In addition, the CPUC has authorized ratemaking mechanisms that permit the utilities to earn incentives (or incur a reimbursement obligation) depending on the extent to which the utilities meet the CPUC's energy savings and demand reduction goals over three-year program cycles. There is considerable uncertainty about how the costs and the savings attributable to these energy efficiency programs will be measured and verified. As customer rates rise to reflect these subsidies, customer incentives, or shareholder incentives, the risk may increase that the CPUC or another 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.

In addition, 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, 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. In 2003, PG&E Corporation, the Utility, and the CPUC entered into a settlement agreement to resolve the Utility's Chapter 11 proceeding, which was incorporated into the Utility's plan of reorganization that became effective in April 2004. Even though the 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, the CPUC may not find that all of the Utility's costs are reasonable and prudent, or the CPUC may take actions or fail to take actions that would be to the Utility's detriment. In addition, the bankruptcy court having jurisdiction of the Chapter 11 settlement agreement or other courts may fail to implement or 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.

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 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 must procure electricity to meet customer demand, plus applicable reserve margins not satisfied from the Utility's own generation facilities and existing electricity contracts. When 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.

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, or terminations of the Utility's existing electricity purchase contracts termination of the DWR's obligations to provide electricity under purchase contracts allocated to the Utility's customers; 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; and the acquisition, retirement, or closure of generation facilities. The amount of electricity the Utility would need to purchase would immediately increase if there were 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 customers who purchase electricity from alternate energy providers (referred to as "direct access" customers) or customers of community choice aggregators (see below) decided to return to receiving bundled services from the Utility.

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 that 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 because of a general economic downturn in the Utility service territory, the restoration of customer direct access, municipalization, or the formation and operation of community choice aggregators. California law permits California cities and counties which have registered as community choice aggregators to purchase and sell electricity for their residents and businesses. The Utility would continue to provide distribution, metering, and billing services to the community choice aggregators' customers, and would be those customers' electricity provider of last resort.

In addition, the Utility could lose customers, or experience lesser demand, because of increased self-generation. The risk of the loss of customers and decreased demand 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 stricter GHG regulations or other state regulations that cause customers to leave the Utility's service territory.

If the Utility were in a long position, the Utility would be required to sell the excess electricity purchased from third parties under electricity purchase contracts, possibly at a loss. In addition, excess electricity generated by the Utility's own generation facilities may also have to be sold, possibly at a loss, and costs that 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.

If the new day-ahead, hour-ahead, and real-time wholesale electricity markets that became effective in California during 2009 do not continue to function effectively, or if the Utility incurs costs to adapt to future changes to the rules governing these markets or losses in connection with congestion charges and these costs and losses are not recoverable, PG&E Corporation's and the Utility's results of operations and financial condition could be negatively impacted.

In response to the electricity market manipulation that occurred during the 2000–2001 energy crisis and the underlying need for improved congestion management, the CAISO undertook an initiative called Market Redesign and Technology Upgrade ("MRTU") to implement a new day-ahead wholesale electricity market and to improve electricity grid management reliability, operational efficiencies, and related technology infrastructure. MRTU became effective on April 1, 2009. The CAISO will be implementing additional market design features over the next several years in order to meet FERC mandates and to include features that were deferred in the initial market launch. MRTU has added significant market complexity and has required the Utility to make major changes to its systems and software interfacing with the CAISO. As directed by the CPUC, the Utility has sought recovery of the costs it incurred to accommodate MRTU in the CPUC proceeding established to determine whether the Utility's 2009 electric procurement costs were properly recorded.

Among other features, the MRTU initiative provides that electric transmission congestion costs and credits will be determined between any two locations and charged to the market participants, including load-serving entities ("LSEs") like the Utility that take energy that passes between those locations. The CAISO has created congestion revenue rights ("CRRs") to allow market participants, including LSEs, to hedge the financial risk of CAISO-imposed congestion charges in the MRTU day-ahead market. The CAISO releases CRRs through an annual and monthly process, each of which includes both an allocation phase (in which LSEs receive CRRs at no cost based on the customer demand or "load" they serve) and an auction phase (priced at market and available to all market participants). The Utility has been allocated and has acquired via auction certain CRRs as of December 31, 2009, and anticipates acquiring additional CRRs through the allocation and auction phases. CRRs are considered derivative instruments and are recorded at fair value within the Consolidated Balance Sheets.

If the Utility incurs significant costs to implement MRTU and subsequent phases, including the costs associated with CRRs, that are not timely recovered from customers; if the new market mechanisms created by MRTU result in any price/market flaws that are not promptly and effectively corrected by the market mechanisms, the CAISO, or the FERC; if the Utility's CRRs are not sufficient to hedge the financial risk associated with its CAISO-imposed congestion costs under MRTU; or if either the CAISO's or the Utility's MRTU-related systems and software do not perform as intended, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially adversely affected.

The Utility may fail to realize the benefits of its advanced metering system, the advanced metering system may fail to perform as intended, or the Utility may incur unrecoverable costs to deploy the advanced metering system and associated dynamic pricing, resulting in higher costs and/or reduced cost savings.

During 2006, the Utility began to implement the SmartMeter™ advanced metering infrastructure project for residential and small commercial customers. This project, which is expected to be completed by the end of 2011, involves the installation of approximately 10 million advanced electricity and gas meters throughout the Utility's service territory. 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 CPUC has authorized the Utility to recover approximately $2.2 billion in estimated project costs, including $1.8 billion of capital expenditures. In addition, the Utility can recover in rates 90% of up to $100 million in costs that exceed the authorized $2.2 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.

The CPUC also has ordered the Utility to implement "dynamic pricing" for its electricity customers to encourage efficient energy consumption and cost-effective demand response by more closely aligning retail rates with the wholesale electricity market. The Utility is required to implement dynamic pricing for its large commercial and industrial customers based on critical peak prices by May of 2010, but these customers may choose an alternative rate structure. Starting in November 2011, the Utility is required to implement dynamic pricing for small and medium non-residential customers who have advanced meters based on time-of-use ("TOU") and critical peak pricing, but these customers may choose an alternative rate structure, such as TOU without critical peak pricing. The Utility has requested that the CPUC authorize the Utility to recover estimated costs of approximately $160 million to implement dynamic pricing, including approximately $32 million as an allowance for unforeseen costs the Utility may incur in connection with such a large and complex capital project. A proposed decision has been issued for the CPUC's consideration recommending that the Utility be authorized to recover $123.6 million, its estimated costs excluding the $32 million contingency amount. Any costs the Utility incurs in excess of $123.6 million would be recoverable only if the CPUC determines that such costs were reasonable. It is anticipated the CPUC will issue a final decision in the first quarter of 2010.

If the Utility fails to recognize the expected benefits of its advanced metering infrastructure, if the Utility incurs additional advanced metering costs that the CPUC does not find reasonable or are unrecoverable, if the Utility incurs costs to implement dynamic pricing that are not recoverable, or if the Utility cannot 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.

If the Utility cannot 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 the Utility fails to acquire sufficient capacity to meet these 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 that the Utility should have secured. The CPUC has set this penalty at $120 per kW-year. The CPUC also adopted "local" resource adequacy requirements for specific regions in which locally-situated electricity capacity may be needed due to transmission constraints. The CPUC set the penalty for failure to meet local resource adequacy requirements at $40 per kW-year. In addition to penalties, the CAISO can require LSEs that fail to meet their resource adequacy requirements to pay the CAISO's cost of buying electricity capacity to fulfill the LSEs' resource adequacy target levels. If the Utility fails to meet resource adequacy requirements, the Utility may be subject to penalties imposed by the CPUC and the CAISO.

In addition, California law requires retail sellers such as the Utility to comply with the RPS by increasing their deliveries of renewable energy each year so that the amount of electricity delivered from eligible renewable resources equals at least 20% of their total retail sales by the end of 2010. If a retail seller is unable to meet its target for a particular year, the current CPUC "flexible compliance" rules allow the deficit to be carried forward for up to three years (i.e., to 2013), so that future deliveries of renewable power can be used to make up the deficit. Although the California governor vetoed legislation to increase the RPS mandate to at least 33% by 2020, he issued an executive order directing the CARB to adopt regulations by July 31, 2010 that would require all load-serving entities, including the utilities, to reach a 33% RPS by 2020. (In December 2008, the CARB issued a scoping plan containing recommendations on how to implement the GHG reductions required by current California law, including a recommendation to establish a 33% RPS mandate. The governor's executive order is consistent with this recommendation.)

Under existing regulations implementing the 20% RPS by 2010, the CPUC can impose penalties of $50 per megawatt-hour ("MWh"), up to $25 million per year, for an unexcused failure to comply with the current RPS requirements. The CPUC can excuse noncompliance if a retail seller is able to demonstrate good cause, such as insufficient transmission capacity or the failure of the renewable energy provider to timely develop a renewable resource. Following several RFOs and bilateral negotiations, the Utility entered into various agreements to purchase renewable generation to be produced by facilities proposed to be developed by third parties. The development of these renewable generation facilities is subject to many risks, including risks related to permitting, financing, technology, fuel supply, environmental matters, and the construction of sufficient transmission capacity. Whether the Utility can meet the current RPS, even while relying on the flexible compliance rules, depends on timely development of renewable energy facilities. Additionally, it is uncertain whether the new regulations for a 33% RPS to be adopted by the CARB and other regulatory agencies would include provisions for the imposition of penalties for failure to meet the increased RPS requirement. If penalty provisions were to be adopted, it is uncertain whether provisions would be included to excuse noncompliance and whether any penalties that may be imposed would be duplicative of any penalty imposed by the CPUC for failure to meet the current RPS requirement.

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. This may result in stranded investment capital, loss of customer growth, and additional barriers to cost recovery. 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. Also, the Utility's natural gas transportation facilities could risk being bypassed by interstate pipeline companies that construct facilities in the Utility's markets, 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.

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. Changing commodity prices may increase short-term cash requirements.

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 liquefied natural gas 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.

The Utility's exposure to natural gas price volatility will increase as the DWR electricity purchase contracts allocated to the Utility begin to expire or as the DWR contracts are terminated or assigned to the Utility. The final DWR contract is scheduled to expire in 2015. Although the Utility attempts to execute CPUC-approved hedging programs to reduce the natural gas price risk, these hedging programs may not be successful or the costs of the Utility's hedging programs may not be fully recoverable.

Further, if wholesale electricity or natural gas prices significantly increase, public pressure, other regulatory influences, governmental influences, or other factors could constrain the CPUC from authorizing timely recovery of the Utility's costs from customers. If the Utility cannot recover a 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.

Economic downturn and the resulting drop in demand for energy commodities has reduced the prices of electricity and natural gas and required the Utility to deposit or return collateral in connection with its commodity hedging contracts. To the extent such commodity prices remain volatile, the Utility's liquidity and financing needs may fluctuate due to the collateral requirements associated with its commodity hedging contracts. If the Utility is required to finance higher liquidity levels, the increased interest costs may negatively impact net income.

The Utility's financial condition and results of operations could be materially adversely affected if it cannot successfully manage the risks inherent in operating the Utility's facilities and information systems.

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. These interconnected systems are becoming increasingly reliant on evolving information technology systems, including the development of technologies and systems to establish a "Smart Grid" to monitor and manage the nation's interconnected electric transmission grids. The Utility's wide deployment of an advanced metering infrastructure throughout its service territory in California, in combination with the system changes needed to implement "dynamic pricing" for the Utility's customers, may increase the risk of damage from a systemwide failure or from an intentional disruption of the system by third parties. The operation of the Utility's facilities and information systems and the facilities and information systems of third parties on which it relies involves numerous risks, the realization of which can 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 claims by customers or third parties for damage to property, personal injury, or the failure to maintain confidentiality of customer information. These risks include:

- operating limitations that may be imposed by environmental laws or regulations, including those relating to GHG, or other regulatory requirements;
- imposition of stricter 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;
- equipment failure;
- failure or intentional disruption of the Utility's information systems, including those relating to operations, such as the advanced metering infrastructure being deployed by the Utility, or financial information, such as customer billing;
- labor disputes, workforce shortage, and availability of qualified personnel;
- weather, storms, earthquakes, wildland and other fires, floods or other natural disasters, war, pandemic, and other catastrophic events;
- explosions, accidents, dam failure, mechanical breakdowns, and terrorist activities; and
- other events or hazards.

In 2008, the Utility undertook a thorough review of its operating practices and procedures used in its natural gas system, including its gas leak survey practices. The Utility determined that improvements needed to be made to operating practices and procedures, including increasing the accuracy of gas maintenance records and compliance with operating procedures. During 2009, the Utility incurred costs of approximately $100 million to accelerate the work associated with systemwide gas leak surveys. The accelerated work is scheduled to be completed in April 2010. Throughout this time, the CPUC's Consumer Protection and Safety Division ("CPSD") has been conducting an informal investigation of the Utility's natural gas distribution maintenance practices. The Utility has provided information to the CPSD about the Utility's review and the remedial steps the Utility has taken. PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows would be materially adversely affected if the Utility were to incur material costs or other material liabilities in connection with these operational issues that were not recoverable through rates or otherwise offset by operating efficiencies or other revenues.

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 may experience a labor shortage if it is unable to attract and retain qualified personnel to replace employees who retire or leave for other reasons, or the Utility's operations may be affected by labor disruptions as a substantial number of employees are covered by collective bargaining agreements that are subject to re-negotiation as their terms expire.

The Utility's workforce is aging and many employees will become eligible to retire within the next few years. Although the Utility has undertaken efforts to recruit and train new field service personnel, the Utility may not be successful. The Utility may be faced with a shortage of experienced and qualified personnel that could negatively impact the Utility's operations as well as its financial condition and results of operations.

At December 31, 2009, there were 12,648 Utility employees covered by collective bargaining agreements with three unions. The terms of these agreements impact the Utility's labor costs. While these contracts are re-negotiated, it is possible that labor disruptions could occur. In addition, it is possible that some of the remaining non-represented Utility employees will join one of these unions in the future.

The Utility's future operations may be impacted by climate change that may have a material impact on the Utility's financial condition and results of operations.

A report issued on June 16, 2009 by the U.S. Global Change Research Program (an interagency effort led by the National Oceanic and Atmospheric Administration) states that climate changes caused by rising emissions of carbon dioxide and other heat-trapping gases have already been observed in the United States, including increased frequency and severity of hot weather, reduced runoff from snow pack, and increased sea levels. In December 2009, the EPA issued a finding that GHG emissions cause or contribute to air pollution that endangers public health and welfare. The impact of events or conditions caused by climate change could range widely, from highly localized to worldwide, and the extent to which the Utility's operations may be affected is uncertain. For example, if reduced snowpack decreases the Utility's hydroelectric generation, there will be a need for additional generation from other sources. Under certain circumstances, the events or conditions caused by climate change could result in a full or partial disruption of the ability of the Utility – or one or more of the entities on which it relies – to generate, transmit, transport, or distribute electricity or natural gas. The Utility has been studying the potential effects of climate change on the Utility's operations and is developing contingency plans to adapt to those events and conditions that the Utility believes are most significant. Events or conditions caused by climate change could have a greater impact on the Utility's operations than has been forecast and could result in lower revenues or increased expenses, or both. If the CPUC fails to adjust the Utility's rates to reflect the impact of events or conditions caused by climate change, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially adversely affected.

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. Compliance in the future may require significant expenditures relating to reduction of GHG, regulation of water intake or discharge at certain facilities, and mitigation measures associated with electric and magnetic fields. Generally, the Utility has recovered the costs of complying with environmental laws and regulation in the Utility's rates, subject to reasonableness review.

California legislation imposes a statewide limit on the emission of GHG that must be achieved by 2020 and prohibits LSEs, including investor-owned utilities, from entering into long-term financial commitments for generation resources unless the new generation resources conform to a GHG emission performance standard. In November 2009, the CARB issued preliminary draft regulations to establish a cap-and-trade program that would set a declining ceiling on GHG emissions and allow companies to buy and sell emission allowances or offsets to meet it. Depending on the final form of regulations adopted by the CARB, the Utility could incur significant additional costs to ensure that it complies with the new rules. In addition, the Utility expects that its cost to procure electricity from other generation providers will reflect their costs of compliance and the actual market price of emission allowances. The Utility estimates that these costs could total approximately $1 billion per year beginning in 2012, assuming a market price for emissions allowances of $30 per metric tonne and that the Utility is not freely allocated some or all of its emission allowances to reduce customer costs. Although these costs are expected to be passed through to customers, there can be no assurance that the CPUC will permit full recovery of these costs.

In addition, the Utility already has significant liabilities (currently known, unknown, actual, and potential) related to environmental contamination at current and former Utility facilities, including natural gas compressor stations and former MGP sites, as well as at third-party-owned sites. From the mid-1800s through the early 1900s, before the advent of natural gas, the Utility owned and operated 41 MGPs located throughout its service territory. Those operations generated residues – mainly coal tar (similar to roofing tar), lampblack (an oily soot), and coal ash. Some of these residues were disposed of on the MGP site, and in some cases they remain on the properties today. Some compounds contained in the residues are now classified as hazardous. The Utility has a program, in cooperation with the California Environmental Protection Agency, to evaluate and take appropriate action to mitigate any potential environmental concerns posed by certain of these former MGP sites. As part of this program, the Utility recently contacted the owners of property located on three former MGP sites in urban, residential areas of San Francisco to offer to test the soil for residues, and depending on the results of such tests, to take appropriate remedial action. Until the Utility's investigation is complete, the extent of the Utility's obligation to remediate is established, and appropriate remedial actions are determined, the Utility is unable to determine the amount it may spend in the future to remediate these MGP sites in San Francisco. The CPUC has established a special ratemaking mechanism under which the Utility is authorized to recover 90% of environmental costs associated with hazardous waste remediation, including the cleanup of these MGP sites, without a reasonableness review. There is no guarantee that the CPUC will not discontinue or change this ratemaking mechanism in the future. In addition, this ratemaking mechanism does not apply to costs or losses the Utility may incur as a result of claims for property damage or personal injury.

The Utility's environmental compliance and remediation costs could increase, and the timing of its future capital expenditures 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. If the Utility must pay materially more than the amount that it currently has accrued on its Consolidated Balance Sheets to satisfy its environmental remediation obligations, including those related to former MGP sites, and if the Utility 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 sources, adversely affecting its financial condition, results of operations, and cash flow.

Operating and decommissioning 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 when their licenses expire. The Utility maintains insurance 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 $235 million of liabilities arising out of each nuclear incident occurring not only at the Utility's Diablo Canyon facility but at any other nuclear power plant in the United States.

The NRC has issued operating licenses for Diablo Canyon that expire in 2024 for Unit 1 and 2025 for Unit 2. In November 2009, the Utility requested that the NRC renew each of these licenses for an additional 20 years. The Utility expects the license renewal process to take many years, as the NRC conducts detailed environmental, seismic, and safety-related studies and holds public hearings. The NRC has broad authority to impose licensing and safety-related requirements that could require the Utility to incur significant capital expenditures in connection with the re-licensing process.

The NRC also has issued a license for the Utility to construct a dry cask storage facility to store spent nuclear fuel on site at Diablo Canyon. Although the dry cask storage facility is complete and the initial movement of spent fuel has occurred, an appeal of the NRC license is still pending.

If one or both units at Diablo Canyon were shut down pursuant to an NRC order; 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.

Furthermore, certain aspects of the Utility's nuclear operations are subject to other federal, state, and local regulatory requirements that are overseen by other federal, state, or local agencies. For example, as discussed above under "Environmental Matters," there is substantial uncertainty concerning the final form of federal and state regulations to implement Section 316(b) of the Clean Water Act. Depending on the nature of the final regulations that may ultimately be adopted by the EPA, the Water Board, or the California Legislature, the Utility may incur significant capital expense to comply with the final regulations, which the Utility would seek to recover through rates. If either the federal or state final regulations require the installation of cooling towers at Diablo Canyon, and if installation of such cooling towers is not technically or economically feasible, the Utility may be forced to cease operations at Diablo Canyon.

If the CPUC prohibits the Utility from recovering a material amount of its capital expenditures, nuclear 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.

The Utility is subject to penalties for failure to comply with federal, state, or local statutes and regulations. Changes in the political and regulatory environment could cause federal and state statutes, 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, regulations, rules, tariffs, and orders of the CPUC, the FERC, the NRC, and other regulatory agencies relating to the aspects of its electricity and natural gas utility operations that fall within the jurisdictional authority of such agencies. These include customer billing, customer service, affiliate transactions, vegetation management, operating and maintenance practices, and safety and inspection practices. The Utility is subject to fines, penalties, and sanctions for failure to comply with applicable statutes, regulations, rules, tariffs, and orders.

For example, under the Energy Policy Act of 2005, the FERC can impose penalties (up to $1 million per day per violation) for failure to comply with mandatory electric reliability standards, including standards to protect the nation's bulk power system against potential disruptions from cyber and physical security breaches. As part of the continuing development of new and modified reliability standards, the FERC has approved changes to its Critical Infrastructure Protection reliability standards (effective April 1, 2010) that will establish a compliance schedule for assets that a utility has identified as "critical cyber assets." As these and other standards and rules evolve, and as the wholesale electricity markets become more complex, the Utility's risk of noncompliance may increase.

In addition, there is risk that these statutes, regulations, rules, tariffs, and orders may become more stringent and difficult to comply with in the future, or that their interpretation and application may change over time and that the Utility will be determined to have not complied with such new interpretations. If this occurs, the Utility could be exposed to increased costs to comply with the more stringent requirements or new interpretations and to potential liability for customer refunds, penalties, or other amounts. If it is determined that the Utility did not comply with applicable statutes, regulations, 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 also must 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 often have 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.

If the Utility cannot obtain, renew, or comply with necessary governmental permits, authorizations, or licenses, or if the Utility cannot 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.

CONSOLIDATED STATEMENTS OF INCOME

PG&E Corporation

(in millions, except per share amounts)	Year Ended December 31, 2009	2008	2007
Operating Revenues			
Electric	**$10,257**	$10,738	$ 9,480
Natural gas	**3,142**	3,890	3,757
Total operating revenues	**13,399**	14,628	13,237
Operating Expenses			
Cost of electricity	**3,711**	4,425	3,437
Cost of natural gas	**1,291**	2,090	2,035
Operating and maintenance	**4,346**	4,201	3,881
Depreciation, amortization, and decommissioning	**1,752**	1,651	1,770
Total operating expenses	**11,100**	12,367	11,123
Operating Income	**2,299**	2,261	2,114
Interest income	**33**	94	164
Interest expense	**(705)**	(728)	(762)
Other income (expense), net	**67**	(4)	43
Income Before Income Taxes	**1,694**	1,623	1,559
Income tax provision	**460**	425	539
Income from Continuing Operations	**1,234**	1,198	1,020
Discontinued Operations			
NEGT income tax benefit	**–**	154	–
Net Income	**1,234**	1,352	1,020
Preferred stock dividend requirement of subsidiary	**14**	14	14
Income Available for Common Shareholders	**$ 1,220**	$ 1,338	$ 1,006
Weighted Average Common Shares Outstanding, Basic	**368**	357	351
Weighted Average Common Shares Outstanding, Diluted	**386**	358	353
Earnings Per Common Share from Continuing Operations, Basic	**$ 3.25**	$ 3.23	$ 2.79
Net Earnings Per Common Share, Basic	**$ 3.25**	$ 3.64	$ 2.79
Earnings Per Common Share from Continuing Operations, Diluted	**$ 3.20**	$ 3.22	$ 2.78
Net Earnings Per Common Share, Diluted	**$ 3.20**	$ 3.63	$ 2.78
Dividends Declared Per Common Share	**$ 1.68**	$ 1.56	$ 1.44

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

PG&E Corporation

	Balance at December 31,	
(in millions)	**2009**	2008
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 527**	$ 219
Restricted cash	**633**	1,290
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $68 million in 2009 and $76 million in 2008)	**1,609**	1,751
Accrued unbilled revenue	**671**	685
Regulatory balancing accounts	**1,109**	1,197
Inventories:		
Gas stored underground and fuel oil	**114**	232
Materials and supplies	**200**	191
Income taxes receivable	**127**	120
Prepaid expenses and other	**667**	718
Total current assets	**5,657**	6,403
Property, Plant, and Equipment		
Electric	**30,481**	27,638
Gas	**10,697**	10,155
Construction work in progress	**1,888**	2,023
Other	**14**	17
Total property, plant, and equipment	**43,080**	39,833
Accumulated depreciation	**(14,188)**	(13,572)
Net property, plant, and equipment	**28,892**	26,261
Other Noncurrent Assets		
Regulatory assets	**5,522**	5,996
Nuclear decommissioning funds	**1,899**	1,718
Income taxes receivable	**596**	–
Other	**379**	482
Total other noncurrent assets	**8,396**	8,196
TOTAL ASSETS	**$ 42,945**	$ 40,860

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS
PG&E Corporation

(in millions, except share amounts)	Balance at December 31, 2009	2008
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term borrowings	**$ 833**	$ 287
Long-term debt, classified as current	**342**	600
Energy recovery bonds, classified as current	**386**	370
Accounts payable:		
Trade creditors	**984**	1,096
Disputed claims and customer refunds	**773**	1,580
Regulatory balancing accounts	**281**	730
Other	**349**	343
Interest payable	**818**	802
Income taxes payable	**214**	–
Deferred income taxes	**332**	251
Other	**1,501**	1,567
Total current liabilities	**6,813**	7,626
Noncurrent Liabilities		
Long-term debt	**10,381**	9,321
Energy recovery bonds	**827**	1,213
Regulatory liabilities	**4,125**	3,657
Pension and other postretirement benefits	**1,773**	2,088
Asset retirement obligations	**1,593**	1,684
Deferred income taxes	**4,732**	3,397
Other	**2,116**	2,245
Total noncurrent liabilities	**25,547**	23,605
Commitments and Contingencies		
Equity		
Shareholders' Equity		
Preferred stock, no par value, authorized 80,000,000 shares, $100 par value, authorized 5,000,000 shares, none issued	**–**	–
Common stock, no par value, authorized 800,000,000 shares, issued 370,601,905 common and 670,552 restricted shares in 2009 and issued 361,059,116 common and 1,287,569 restricted shares in 2008	**6,280**	5,984
Reinvested earnings	**4,213**	3,614
Accumulated other comprehensive loss	**(160)**	(221)
Total shareholders' equity	**10,333**	9,377
Noncontrolling Interest – Preferred Stock of Subsidiary	**252**	252
Total equity	**10,585**	9,629
TOTAL LIABILITIES AND EQUITY	**$42,945**	$40,860

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

PG&E Corporation

(in millions)	Year ended December 31, 2009	2008	2007
Cash Flows from Operating Activities			
Net income	**$ 1,234**	$ 1,352	$ 1,020
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	**1,947**	1,863	1,959
Allowance for equity funds used during construction	**(94)**	(70)	(64)
Deferred income taxes and tax credits, net	**809**	590	55
Other changes in noncurrent assets and liabilities	**(17)**	(126)	192
Effect of changes in operating assets and liabilities:			
Accounts receivable	**156**	(87)	(6)
Inventories	**109**	(59)	(41)
Accounts payable	**(40)**	(140)	(178)
Disputed claims and customer refunds	**(700)**	–	–
Income taxes receivable/payable	**171**	(59)	56
Regulatory balancing accounts, net	**(521)**	(394)	(567)
Other current assets	**(2)**	(221)	172
Other current liabilities	**13**	120	8
Other	**(26)**	(6)	(46)
Net cash provided by operating activities	**3,039**	2,763	2,560
Cash Flows from Investing Activities			
Capital expenditures	**(3,958)**	(3,628)	(2,769)
Decrease in restricted cash	**666**	36	185
Proceeds from sales of nuclear decommissioning trust investments	**1,351**	1,635	830
Purchases of nuclear decommissioning trust investments	**(1,414)**	(1,684)	(933)
Other	**19**	(11)	21
Net cash used in investing activities	**(3,336)**	(3,652)	(2,666)
Cash Flows from Financing Activities			
Borrowings under accounts receivable facility and revolving credit facility	**300**	533	850
Repayments under accounts receivable facility and revolving credit facility	**(300)**	(783)	(900)
Net issuance (repayments) of commercial paper, net of discount of $3 million in 2009, $11 million in 2008, and $1 million in 2007	**43**	6	(209)
Proceeds from issuance of short-term debt, net of issuance costs of $1 million in 2009	**499**	–	–
Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $29 million in 2009, $19 million in 2008, and $16 million in 2007	**1,730**	2,185	1,184
Long-term debt matured or repurchased	**(909)**	(454)	–
Rate reduction bonds matured	**–**	–	(290)
Energy recovery bonds matured	**(370)**	(354)	(340)
Common stock issued	**219**	225	175
Common stock dividends paid	**(590)**	(546)	(496)
Other	**(17)**	(49)	21
Net cash provided by (used in) financing activities	**605**	763	(5)
Net change in cash and cash equivalents	**308**	(126)	(111)
Cash and cash equivalents at January 1	**219**	345	456
Cash and cash equivalents at December 31	**$ 527**	$ 219	$ 345
Supplemental disclosures of cash flow information			
Cash received (paid) for:			
Interest, net of amounts capitalized	**$ (612)**	$ (523)	$ (514)
Income taxes, net	**359**	112	(537)
Supplemental disclosures of noncash investing and financing activities			
Common stock dividends declared but not yet paid	**$ 157**	$ 143	$ 129
Capital expenditures financed through accounts payable	**273**	348	279
Noncash common stock issuances	**50**	22	6

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF EQUITY

PG&E Corporation

(in millions, except share amounts)	Common Stock Shares	Common Stock Amount	Common Stock Held by Subsidiary	Reinvested Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity	Non-controlling Interest – Preferred Stock of Subsidiary	Total Equity	Compre-hensive Income
Balance at December 31, 2006	374,181,059	$5,877	$(718)	$2,671	$ (19)	$ 7,811	$252	$ 8,063	
Income available for common shareholders	–	–	–	1,006	–	1,006	–	1,006	$1,006
Employee benefit plan adjustment (net of income tax expense of $17 million)	–	–	–	–	29	29	–	29	29
Comprehensive income									$1,035
Common stock issued, net	5,465,217	175	–	–	–	175	–	175	
Stock-based compensation amortization	–	31	–	–	–	31	–	31	
Common stock dividends declared and paid	–	–	–	(379)	–	(379)	–	(379)	
Common stock dividends declared but not yet paid	–	–	–	(129)	–	(129)	–	(129)	
Tax benefit from employee stock plans	–	27	–	–	–	27	–	27	
Adoption of new accounting pronouncement	–	–	–	(18)	–	(18)	–	(18)	
Balance at December 31, 2007	379,646,276	6,110	(718)	3,151	10	8,553	252	8,805	
Income available for common shareholders	–	–	–	1,338	–	1,338	–	1,338	$1,338
Employee benefit plan adjustment (net of income tax benefit of $156 million)	–	–	–	–	(231)	(231)	–	(231)	(231)
Comprehensive income									$1,107
Common stock issued, net	7,365,909	247	–	–	–	247	–	247	
Common stock cancelled	(24,665,500)	(403)	718	(315)	–	–	–	–	
Stock-based compensation amortization	–	24	–	–	–	24	–	24	
Common stock dividends declared and paid	–	–	–	(417)	–	(417)	–	(417)	
Common stock dividends declared but not yet paid	–	–	–	(143)	–	(143)	–	(143)	
Tax benefit from employee stock plans	–	6	–	–	–	6	–	6	
Balance at December 31, 2008	362,346,685	5,984	–	3,614	(221)	9,377	252	9,629	
Income available for common shareholders	–	–	–	1,220	–	1,220	–	1,220	$1,220
Employee benefit plan adjustment (net of income tax expense of $8 million)	–	–	–	–	61	61	–	61	61
Comprehensive income									**$1,281**
Common stock issued, net	8,925,772	269	–	–	–	269	–	269	
Stock-based compensation amortization	–	20	–	–	–	20	–	20	
Common stock dividends declared and paid	–	–	–	(464)	–	(464)	–	(464)	
Common stock dividends declared but not yet paid	–	–	–	(157)	–	(157)	–	(157)	
Tax benefit from employee stock plans	–	7	–	–	–	7	–	7	
Balance at December 31, 2009	**371,272,457**	**$6,280**	**$ –**	**$4,213**	**$(160)**	**$10,333**	**$252**	**$10,585**	

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF INCOME

Pacific Gas and Electric Company

(in millions)	Year ended December 31, 2009	2008	2007
Operating Revenues			
Electric	**$10,257**	$10,738	$ 9,481
Natural gas	**3,142**	3,890	3,757
Total operating revenues	**13,399**	14,628	13,238
Operating Expenses			
Cost of electricity	**3,711**	4,425	3,437
Cost of natural gas	**1,291**	2,090	2,035
Operating and maintenance	**4,343**	4,197	3,872
Depreciation, amortization, and decommissioning	**1,752**	1,650	1,769
Total operating expenses	**11,097**	12,362	11,113
Operating Income	**2,302**	2,266	2,125
Interest income	**33**	91	150
Interest expense	**(662)**	(698)	(732)
Other income, net	**59**	28	52
Income Before Income Taxes	**1,732**	1,687	1,595
Income tax provision	**482**	488	571
Net Income	**1,250**	1,199	1,024
Preferred stock dividend requirement	**14**	14	14
Income Available for Common Stock	**$ 1,236**	$ 1,185	$ 1,010

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

Pacific Gas and Electric Company

	Balance at December 31,	
(in millions)	**2009**	2008
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 334**	$ 52
Restricted cash	**633**	1,290
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $68 million in 2009 and $76 million in 2008)	**1,609**	1,751
Accrued unbilled revenue	**671**	685
Related parties	**1**	2
Regulatory balancing accounts	**1,109**	1,197
Inventories:		
Gas stored underground and fuel oil	**114**	232
Materials and supplies	**200**	191
Income taxes receivable	**138**	25
Prepaid expenses and other	**662**	705
Total current assets	**5,471**	6,130
Property, Plant, and Equipment		
Electric	**30,481**	27,638
Gas	**10,697**	10,155
Construction work in progress	**1,888**	2,023
Total property, plant, and equipment	**43,066**	39,816
Accumulated depreciation	**(14,175)**	(13,557)
Net property, plant, and equipment	**28,891**	26,259
Other Noncurrent Assets		
Regulatory assets	**5,522**	5,996
Nuclear decommissioning funds	**1,899**	1,718
Related parties receivable	**25**	27
Income taxes receivable	**610**	–
Other	**291**	407
Total other noncurrent assets	**8,347**	8,148
TOTAL ASSETS	**$ 42,709**	$ 40,537

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

Pacific Gas and Electric Company

(in millions, except share amounts)	Balance at December 31, 2009	2008
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	**$ 833**	$ 287
Long-term debt, classified as current	**95**	600
Energy recovery bonds, classified as current	**386**	370
Accounts payable:		
Trade creditors	**984**	1,096
Disputed claims and customer refunds	**773**	1,580
Related parties	**16**	25
Regulatory balancing accounts	**281**	730
Other	**347**	325
Interest payable	**813**	802
Income tax payable	**223**	53
Deferred income taxes	**334**	257
Other	**1,307**	1,371
Total current liabilities	**6,392**	7,496
Noncurrent Liabilities		
Long-term debt	**10,033**	9,041
Energy recovery bonds	**827**	1,213
Regulatory liabilities	**4,125**	3,657
Pension and other postretirement benefits	**1,717**	2,040
Asset retirement obligations	**1,593**	1,684
Deferred income taxes	**4,764**	3,449
Other	**2,073**	2,170
Total noncurrent liabilities	**25,132**	23,254
Commitments and Contingencies		
Shareholders' Equity		
Preferred stock without mandatory redemption provisions:		
Nonredeemable, 5.00% to 6.00%, outstanding 5,784,825 shares	**145**	145
Redeemable, 4.36% to 5.00%, outstanding 4,534,958 shares	**113**	113
Common stock, $5 par value, authorized 800,000,000 shares, issued 264,374,809 shares in 2009 and 2008	**1,322**	1,322
Additional paid-in capital	**3,055**	2,331
Reinvested earnings	**6,704**	6,092
Accumulated other comprehensive loss	**(154)**	(216)
Total shareholders' equity	**11,185**	9,787
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**$42,709**	$40,537

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Pacific Gas and Electric Company

(in millions)	Year ended December 31, 2009	2008	2007
Cash Flows from Operating Activities			
Net income	**$ 1,250**	$ 1,199	$ 1,024
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	**1,927**	1,838	1,956
Allowance for equity funds used during construction	**(94)**	(70)	(64)
Deferred income taxes and tax credits, net	**787**	593	43
Other changes in noncurrent assets and liabilities	**6**	(25)	188
Effect of changes in operating assets and liabilities:			
Accounts receivable	**157**	(83)	(6)
Inventories	**109**	(59)	(41)
Accounts payable	**(33)**	(137)	(196)
Disputed claims and customer refunds	**(700)**	–	–
Income taxes receivable/payable	**21**	43	56
Regulatory balancing accounts, net	**(521)**	(394)	(567)
Other current assets	**(2)**	(223)	170
Other current liabilities	**24**	90	24
Other	**(27)**	(6)	(46)
Net cash provided by operating activities	**2,904**	2,766	2,541
Cash Flows from Investing Activities			
Capital expenditures	**(3,958)**	(3,628)	(2,768)
Decrease in restricted cash	**666**	36	185
Proceeds from sales of nuclear decommissioning trust investments	**1,351**	1,635	830
Purchases of nuclear decommissioning trust investments	**(1,414)**	(1,684)	(933)
Other	**11**	1	21
Net cash used in investing activities	**(3,344)**	(3,640)	(2,665)
Cash Flows from Financing Activities			
Borrowings under accounts receivable facility and revolving credit facility	**300**	533	850
Repayments under accounts receivable facility and revolving credit facility	**(300)**	(783)	(900)
Net issuance (repayments) of commercial paper, net of discount of $3 million in 2009, $11 million in 2008, and $1 million in 2007	**43**	6	(209)
Proceeds from issuance of short-term debt, net of issuance costs of $1 million in 2009	**499**	–	–
Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $25 million in 2009, $19 million in 2008, and $16 million in 2007	**1,384**	2,185	1,184
Long-term debt matured or repurchased	**(909)**	(454)	–
Rate reduction bonds matured	**–**	–	(290)
Energy recovery bonds matured	**(370)**	(354)	(340)
Preferred stock dividends paid	**(14)**	(14)	(14)
Common stock dividends paid	**(624)**	(568)	(509)
Equity contribution	**718**	270	400
Other	**(5)**	(36)	23
Net cash provided by financing activities	**722**	785	195
Net change in cash and cash equivalents	**282**	(89)	71
Cash and cash equivalents at January 1	**52**	141	70
Cash and cash equivalents at December 31	**$ 334**	$ 52	$ 141
Supplemental disclosures of cash flow information			
Cash received (paid) for:			
Interest, net of amounts capitalized	**$ (578)**	$ (496)	$ (474)
Income taxes, net	**170**	95	(594)
Supplemental disclosures of noncash investing and financing activities			
Capital expenditures financed through accounts payable	**$ 273**	$ 348	$ 279

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

Pacific Gas and Electric Company

(in millions)	Preferred Stock Without Mandatory Redemption Provisions	Common Stock	Additional Paid-in Capital	Common Stock Held by Subsidiary	Reinvested Earnings	Accumulated Other Comprehensive Income (Loss)	Total Share-holders' Equity	Compre-hensive Income
Balance at December 31, 2006	**$258**	**$1,398**	**$1,822**	**$(475)**	**$5,213**	**$ (16)**	**$ 8,200**	
Net income	–	–	–	–	1,024	–	1,024	$1,024
Employee benefit plan adjustment (net of income tax expense of $17 million)	–	–	–	–	–	29	29	29
Comprehensive income								**$1,053**
Equity contribution	–	17	383	–	–	–	400	
Tax benefit from employee stock plans	–	–	15	–	–	–	15	
Common stock dividend	–	–	–	–	(509)	–	(509)	
Preferred stock dividend	–	–	–	–	(14)	–	(14)	
Adoption of new accounting pronouncement	–	–	–	–	(20)	–	(20)	
Balance at December 31, 2007	**258**	**1,415**	**2,220**	**(475)**	**5,694**	**13**	**9,125**	
Net income	–	–	–	–	1,199	–	1,199	$1,199
Employee benefit plan adjustment (net of income tax expense of $159 million)	–	–	–	–	–	(229)	(229)	(229)
Comprehensive income								**$ 970**
Equity contribution	–	4	266	–	–	–	270	
Tax benefit from employee stock plans	–	–	4	–	–	–	4	
Common stock dividend	–	–	–	–	(568)	–	(568)	
Common stock cancelled	–	(97)	(159)	475	(219)	–	–	
Preferred stock dividend	–	–	–	–	(14)	–	(14)	
Balance at December 31, 2008	**258**	**1,322**	**2,331**	**–**	**6,092**	**(216)**	**9,787**	
Net income	–	–	–	–	1,250	–	1,250	$1,250
Employee benefit plan adjustment (net of income tax expense of $10 million)	–	–	–	–	–	62	62	62
Comprehensive income								**$1,312**
Equity contribution	–	–	718	–	–	–	718	
Tax benefit from employee stock plans	–	–	6	–	–	–	6	
Common stock dividend	–	–	–	–	(624)	–	(624)	
Preferred stock dividend	–	–	–	–	(14)	–	(14)	
Balance at December 31, 2009	**$258**	**$1,322**	**$3,055**	**$ –**	**$6,704**	**$(154)**	**$11,185**	

See accompanying 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 ("Utility"), a public utility operating in northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. The Utility is primarily regulated by the California Public Utilities Commission ("CPUC") and the Federal Energy Regulatory Commission ("FERC").

The Utility's accounts for electric and gas operations are maintained in accordance with the Uniform System of Accounts prescribed by the FERC.

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 the accounts of the Utility and its wholly owned and controlled subsidiaries as well as the accounts of variable interest entities for which the Utility absorbs a majority of the risk of loss or gain. All intercompany transactions have been eliminated from the Consolidated Financial Statements.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions based on a wide range of factors, including future regulatory decisions and economic conditions that are difficult to predict. Some of the more critical estimates and assumptions, discussed further below in these notes, relate to the Utility's regulatory assets and liabilities, environmental remediation liability, asset retirement obligations ("ARO"), income tax-related assets and liabilities, pension plan and other postretirement plan obligations, and accruals for legal matters. Management believes that its estimates and assumptions reflected in the Consolidated Financial Statements are appropriate and reasonable. A change in management's estimates or assumptions could result in an adjustment that would have a material impact on PG&E Corporation's and the Utility's financial condition and results of operations during the period in which such change occurred.

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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.

RESTRICTED CASH

Restricted cash consists primarily of the Utility's cash held in escrow pending the resolution of the remaining disputed claims made by electricity suppliers in the Utility's proceeding under Chapter 11 of the U.S. Bankruptcy Code ("Chapter 11"). (See Note 14 of the Notes to the Consolidated Financial Statements.) Restricted cash also includes the Utility's deposits of cash and cash equivalents made 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 collectability. If circumstances require changes in the assumption, allowance estimates are adjusted accordingly.

INVENTORIES

Inventories are carried at average cost and are valued at the lower of average cost or market. Inventories include materials, supplies, and natural gas stored underground. Materials and supplies are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, when consumed or installed. Natural gas stored underground represents purchases that are injected into inventory and then expensed at average cost when withdrawn and distributed to customers or used in electric generation.

PROPERTY, PLANT, AND EQUIPMENT

Property, plant, and equipment are reported at their original cost. These original costs include labor and materials, construction overhead, and allowance for funds used during construction ("AFUDC").

The Utility's balances at December 31, 2009 are as follows:

(in millions)	Gross Plant as of December 31, 2009	Accumulated Depreciation as of December 31, 2009	Net Plant as of December 31, 2009
Electricity generating facilities	**$ 4,777**	**$ (1,279)**	**$ 3,498**
Electricity distribution facilities	**19,924**	**(6,924)**	**13,000**
Electricity transmission	**5,780**	**(1,751)**	**4,029**
Natural gas distribution facilities	**7,069**	**(2,667)**	**4,402**
Natural gas transportation	**3,573**	**(1,554)**	**2,019**
Natural gas storage	**55**	**–**	**55**
Construction work in progress	**1,888**	**–**	**1,888**
Total	**$43,066**	**$(14,175)**	**$28,891**

The Utility's balances at December 31, 2008 are as follows:

(in millions)	Gross Plant as of December 31, 2008	Accumulated Depreciation as of December 31, 2008	Net Plant as of December 31, 2008
Electricity generating facilities	$ 3,711	$ (1,134)	$ 2,577
Electricity distribution facilities	18,777	(6,722)	12,055
Electricity transmission	5,150	(1,675)	3,475
Natural gas distribution facilities	6,666	(2,544)	4,122
Natural gas transportation	3,434	(1,482)	1,952
Natural gas storage	55	–	55
Construction work in progress	2,023	–	2,023
Total	$39,816	$(13,557)	$26,259

AFUDC

AFUDC represents a method used to compensate the Utility for the estimated cost of debt and equity used to finance regulated plant additions and is 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. AFUDC interest is recorded as a reduction to interest expense. AFUDC equity is recorded in other income. The Utility recorded AFUDC of $95 million and $44 million during 2009, $70 million and $44 million during 2008, and $64 million and $32 million during 2007, related to equity and debt, respectively.

Depreciation

The Utility depreciates property, plant, and equipment on a straight-line basis over the estimated useful lives. The composite, or group, method of depreciation is used, in which a single depreciation rate is applied to the gross investment in a particular class of property. The Utility's composite depreciation rate was 3.43% in 2009, 3.38% in 2008, and 3.28% in 2007.

	Estimated Useful Lives
Electricity generating facilities	4 to 37 years
Electricity distribution facilities	16 to 58 years
Electricity transmission	40 to 70 years
Natural gas distribution facilities	24 to 52 years
Natural gas transportation	25 to 45 years
Natural gas storage	25 to 48 years

The useful lives of the Utility's property, plant, and equipment are authorized by the CPUC and the FERC, and depreciation expense is included in rates charged to customers. Depreciation expense includes a component for the original cost of assets and a component for estimated future removal, net of any salvage value at retirement.

The Utility charges the original cost of retired plant less salvage value to accumulated depreciation upon retirement of plant. PG&E Corporation and the Utility expense repair and maintenance costs as incurred.

Nuclear Fuel

Property, plant, and equipment also include 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 capitalize costs incurred during the application development stage of internal use software projects to property, plant, and equipment. PG&E Corporation and the Utility amortize capitalized software costs ratably over the expected lives of the software, ranging from 3 to 15 years and commencing upon operational use. The Utility's capitalized software costs totaled $562 million at December 31, 2009 and $522 million at December 31, 2008, net of accumulated amortization of $315 million at December 31, 2009 and $280 million at December 31, 2008. The Utility's amortization expense for capitalized software was $37 million in 2009, $73 million in 2008, and $10 million in 2007. Amortization expense is estimated to be $37 million annually for 2010 through 2014. PG&E Corporation's capitalized software costs were less than $1 million at December 31, 2009 and December 31, 2008.

REGULATION AND THE REGULATED OPERATIONS

The Utility accounts for the financial effects of regulation based on the Regulated Operations Topic of the Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC"), which applies to regulated entities whose rates are designed to recover the cost of providing service ("cost-of-service rate regulation"). All of the Utility's operations are subject to cost-of-service rate regulation.

The Utility capitalizes and records, as a regulatory asset, costs that would otherwise be charged to expense if it is probable that the incurred costs will be recovered in future rates. The regulatory assets are amortized over future periods when the costs are expected to be recovered. If costs expected to be incurred in the future are currently being recovered through rates, the Utility records those expected future costs as regulatory liabilities. In addition, amounts that are probable of being credited or refunded to customers in the future are recorded as regulatory liabilities.

To the extent that portions of the Utility's operations cease to be subject to cost-of-service rate regulation, 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.

INTANGIBLE ASSETS

Intangible assets primarily 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 $110 million at December 31, 2009 and $95 million at December 31, 2008. The accumulated amortization was $40 million at December 31, 2009 and $35 million at December 31, 2008.

The Utility's amortization expense related to intangible assets was $4 million in 2009, $4 million in 2008, and $3 million in 2007. The estimated annual amortization expense for 2010 through 2013 based on the December 31, 2009 intangible assets balance is $4 million for 2010 and $3 million each year thereafter. Intangible assets are recorded to Other Noncurrent Assets – Other in the Consolidated Balance Sheets.

CONSOLIDATION OF VARIABLE INTEREST ENTITIES

PG&E Corporation and the Utility are required to consolidate any entity over which it has control. In most cases, control can be determined based on majority ownership. However, for certain entities, control is difficult to discern based on voting equity interests only. These entities are referred to as VIEs. Characteristics of a VIE include equity investment at risk that is not sufficient to permit the entity to finance its activities without additional subordinated financial support from other parties, or equity investors that lack any of the characteristics of a controlling financial interest. The primary beneficiary, defined as the entity that absorbs a majority of the expected losses of the VIE, receives a majority of the expected residual returns of the VIE, or both, is required to consolidate the VIE.

The Utility's exposure to VIEs relates primarily to entities with which it has a power purchase agreement. For those entities, the Utility assesses operational risk, commodity price risk, credit risk, and tax benefit risk on a qualitative basis to determine whether the Utility is a primary beneficiary of the entity and is required to consolidate the entity. This qualitative assessment also typically involves comparing the contract life to the economic life of the plant to consider the significance of the commodity price risk that the Utility might absorb. As of December 31, 2009, the Utility is not the primary beneficiary of any entities with which it has power purchase agreements.

Although the Utility is not required to consolidate any of these VIEs as of December 31, 2009, it held a significant variable interest in three VIEs as a result of being a party to the following power purchase agreements:

- A 25-year power purchase agreement approved by the CPUC in 2009 to purchase energy from a 250-megawatt ("MW") solar photovoltaic energy facility beginning on the date of commercial operations (expected in 2012);
- A 20-year power purchase agreement approved by the CPUC in 2009 to purchase energy from a 550 MW solar photovoltaic energy facility beginning on the date of commercial operations (expected in 2013); and
- A 25-year power purchase agreement approved by the CPUC in 2008 to purchase energy from a 554 MW solar trough facility beginning on the date of commercial operations (expected in 2011).

Each of these VIEs is a subsidiary of another company whose activities are financed primarily through equity from investors and proceeds from non-recourse project-specific debt financing. Activities of the VIEs consist of renewable energy production from electric generating facilities for sale to the Utility. Under each of the power purchase agreements, the Utility is obligated to purchase as-delivered electric generation output from the VIEs. The Utility does not provide any other financial or other support to these VIEs. The Utility's financial exposure is limited to the amounts paid for delivered electricity.

ASSET RETIREMENT OBLIGATIONS

PG&E Corporation and the Utility record an ARO at fair value in the period in which the obligation is incurred if the fair value can be reasonably estimated. 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. PG&E Corporation and the Utility also record a liability if a legal obligation to perform an asset retirement exists and can be reasonably estimated, but performance is conditional upon a future event. The Utility recognizes regulatory assets or liabilities as a result of timing differences between the recognition of costs and the costs recovered through the ratemaking process.

The Utility has an ARO for its nuclear generation and certain fossil fueled generation facilities. The Utility has also identified AROs 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 has recorded AROs related to gas distribution, gas transmission, electric distribution, and electric transmission system assets.

Detailed studies of the cost to decommission the Utility's nuclear power plants are conducted every three years in conjunction with the Nuclear Decommissioning Cost Triennial Proceedings ("NDCTP") conducted by the CPUC. Estimated cash flows were revised as a result of the studies completed in the first quarter of 2009. (See Note 12 of the Notes to the Consolidated Financial Statements for further discussion.)

A reconciliation of the changes in the ARO liability is as follows:

(in millions)	
ARO liability at December 31, 2007	$1,579
Revision in estimated cash flows	50
Accretion	106
Liabilities settled	(51)
ARO liability at December 31, 2008	1,684
Revision in estimated cash flows	(129)
Accretion	98
Liabilities settled	(60)
ARO liability at December 31, 2009	**$1,593**

The Utility has identified additional ARO 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 Utility 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 ARO 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, communications 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 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.

IMPAIRMENT OF LONG-LIVED ASSETS

PG&E Corporation and the Utility evaluate the carrying amounts of long-lived assets for impairment, based on projections of undiscounted future cash flows, whenever events occur or circumstances change that may affect the recoverability or the estimated life of long-lived assets. If this evaluation indicates that such cash flows are not expected to fully recover the assets, the assets are written down to their estimated fair value. No significant impairments were recorded in 2009, 2008, and 2007.

GAINS AND LOSSES ON DEBT EXTINGUISHMENTS

Gains and losses on debt extinguishments associated with regulated operations are deferred and amortized over the remaining original amortization period of the debt reacquired, consistent with recovery of costs through regulated rates. Unamortized loss on debt extinguishments, net of gain, was $227 million and $251 million at December 31, 2009 and 2008, respectively. The Utility's amortization expense related to this loss was $25 million in 2009 and $26 million in 2008 and 2007. Deferred gains and losses on debt extinguishments are recorded to Prepaid expenses and other and Other Noncurrent Assets – Regulatory assets in the Consolidated Balance Sheets.

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 after-tax changes in each component of accumulated other comprehensive income (loss):

	Employee Benefit Plans – Accumulated Other Comprehensive Income (Loss)
Balance at December 31, 2006	$ (19)
Period change in pension benefits and other benefits:	
Unrecognized prior service cost (net of income tax expense of $18 million)	26
Unrecognized net gain (net of income tax expense of $195 million)	289
Unrecognized net transition obligation (net of income tax expense of $11 million)	16
Transfer to regulatory account (net of income tax benefit of $207 million)(1)	(302)
Balance at December 31, 2007	$ 10
Period change in pension benefits and other benefits:	
Unrecognized prior service cost (net of income tax expense of $27 million)	37
Unrecognized net loss (net of income tax benefit of $1,088 million)	(1,583)
Unrecognized net transition obligation (net of income tax expense of $11 million)	15
Transfer to regulatory account (net of income tax expense of $894 million)(1)	1,300
Balance at December 31, 2008	$ (221)
Period change in pension benefits and other benefits:	
Unrecognized prior service cost (net of income tax benefit of $1 million)	(1)
Unrecognized net gain (net of income tax expense of $216 million)	363
Unrecognized net transition obligation (net of income tax expense of $11 million)	15
Transfer to regulatory account (net of income tax benefit of $218 million)(1)	(316)
Balance at December 31, 2009	**$ (160)**

(1) Amounts transferred to the pension regulatory asset account since the Utility meets the requirement for recovery from customers in future rates.

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

The Utility recognizes revenues after persuasive evidence of an arrangement exists; delivery has occurred or services have been rendered; the price to the customer is fixed or determinable; and collectability is reasonably assured. Revenues meet these criteria as the electricity and natural gas are delivered, and include amounts for services rendered but not yet billed at the end of the period.

The Utility recognizes regulatory balancing account revenues after the CPUC or the FERC has authorized rate recovery, amounts are objectively determinable and probable of recovery, and amounts will be collected within 24 months. (See Note 3 of the Notes to the Consolidated Financial Statements for further discussion.)

The CPUC authorizes most of the Utility's revenue requirements in its general rate case ("GRC"), which occurs generally every three years. The Utility's ability to recover revenue requirements authorized by the CPUC in the GRC does not depend on the volume of the Utility's sales of electricity and natural gas services. Generally, the balancing account revenue recognition criteria are met ratably over the year.

The CPUC also has authorized the Utility to collect additional revenue requirements to recover certain costs that the Utility has been authorized to pass on to customers, including costs to purchase electricity and natural gas; to fund public purpose, demand response, and customer energy efficiency programs; and to recover certain capital expenditures. Generally, the balancing account revenue recognition criteria are met at the time the costs are incurred.

The Utility's revenues and earnings also are affected by incentive ratemaking mechanisms that adjust rates depending on the extent the Utility meets certain performance criteria. (See Note 16 of the Notes to the Consolidated Financial Statements for further discussion.)

The FERC authorizes the Utility's revenue requirements in annual transmission owner rate cases. The Utility's ability to recover revenue requirements authorized by the FERC is dependent on the volume of the Utility's electricity sales, and revenue is recognized only for amounts billed.

In determining whether revenue transactions should be presented net of the related expenses, the Utility considers various factors, including whether the Utility takes title to the product being delivered, has latitude in establishing price for the product, and is subject to the customer credit risk. In January 2001, the California Department of Water Resources ("DWR") began purchasing electricity to meet the portion of demand of the California investor-owned electric utilities that was not being satisfied from the utilities' own generation facilities and existing electricity contracts. The Utility acts as a billing and collection agent on behalf of the DWR and does not have any authority to set prices for the energy delivered. The Utility does not assume customer credit risk nor take title to the electricity being delivered to the customer. Therefore, the Utility presents the electricity revenues for amounts delivered to customers net of the cost of electricity delivered by the DWR.

INCOME TAXES

PG&E Corporation and the Utility use the liability method of accounting for income taxes. Income tax provision (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. (See Note 9 of the Notes to the Consolidated Financial Statements for further discussion of income taxes.)

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 a combined state income tax return in California. PG&E Corporation and the Utility are parties to a tax-sharing agreement under which the Utility determines its income tax provision (benefit) on a stand-alone basis.

NUCLEAR DECOMMISSIONING TRUSTS

The Utility classifies its investments held in the nuclear decommissioning trust as "available-for-sale." As the day-to-day investing activities of the trusts are managed by external investment managers, the Utility is unable to assert that it has the intent and ability to hold investments to maturity or that it is more likely than not that the Utility will be required to sell the investments. Therefore, all unrealized losses are considered other-than-temporary impairments. Gains or losses on the nuclear decommissioning trust investments are refundable or recoverable, respectively, from customers. Therefore, trust earnings are deferred and included in the regulatory liability for recoveries in excess of the ARO. There is no impact on the Utility's earnings or accumulated other comprehensive income. The cost of debt and equity securities sold is determined by specific identification. (See Note 12 of the Notes to the Consolidated Financial Statements for further discussion.)

ACCOUNTING FOR DERIVATIVES AND HEDGING ACTIVITIES

Derivative instruments are recorded in PG&E Corporation's and the Utility's Consolidated Balance Sheets at fair value, unless they qualify for the normal purchase and sales exception. Changes in the fair value of derivative instruments are recorded in earnings or, to the extent that 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 in order 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 regulatory accounts.

As of September 30, 2009, the Utility de-designated all cash flow hedge relationships. Due to the regulatory accounting treatment described above, the de-designation of cash flow hedge relationships had no impact on Income Available for Common Shareholders or the Consolidated Balance Sheets.

The normal purchase and sales exception to derivative accounting requires, among other things, physical delivery of quantities expected to be used or sold over a reasonable period in the normal course of business. Transactions for which the normal purchase and sales exception is elected are not reflected in the Consolidated Balance Sheets at fair value. They are accounted for under the accrual method of accounting. Therefore, expenses are recognized as incurred.

PG&E Corporation and the Utility offset the cash collateral paid or cash collateral received against the fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement where the right of offset exists and where PG&E Corporation and the Utility intends to set off.

See Note 10 of the Notes to the Consolidated Financial Statements for further discussion and financial statement impact.

FAIR VALUE MEASUREMENTS

PG&E Corporation and the Utility determine the fair value of certain assets and liabilities based on assumptions that market participants would use in pricing the assets or liabilities. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, or the "exit price." PG&E Corporation and the Utility utilize a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value and give precedence to observable inputs in determining fair value. An instrument's level within the hierarchy is based on the lowest level of any significant input to the fair value measurement. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). Assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. (See Note 11 of the Notes to the Consolidated Financial Statements for further discussion.)

FAIR VALUE OPTION

PG&E Corporation and the Utility have not elected the fair value option for any assets or liabilities during the years ended December 31, 2009 and 2008.

ADOPTION OF NEW ACCOUNTING PRONOUNCEMENTS

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

On January 1, 2009, PG&E Corporation and the Utility adopted Statement of Financial Accounting Standards ("SFAS") No. 161, "Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133" ("SFAS No. 161"), which is codified in the Derivatives and Hedging Topic of the FASB ASC. SFAS No. 161 requires an entity to provide qualitative disclosures about its objectives and strategies for using derivative instruments and quantitative disclosures that detail the fair value amounts of, and gains and losses on, derivative instruments. SFAS No. 161 also requires disclosures about credit risk-related contingent features of derivative instruments. (See Note 10 of the Notes to the Consolidated Financial Statements.)

Noncontrolling Interests in Consolidated Financial Statements — an amendment of ARB No. 51

On January 1, 2009, PG&E Corporation and the Utility adopted SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements – an amendment of Accounting Research Bulletin No. 51" ("SFAS No. 160"), which is codified in the Consolidation Topic of the FASB ASC. SFAS No. 160 establishes accounting and reporting standards for a noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS No. 160 defines a "noncontrolling interest," previously called a "minority interest," as the portion of equity in a subsidiary not attributable, directly or indirectly, to a parent. Among other items, SFAS No. 160 requires that an entity (1) include a noncontrolling interest in its consolidated statement of financial position within equity separate from the parent's equity, (2) report amounts inclusive of both the parent's and noncontrolling interest's shares in consolidated net income, and (3) separately report the amounts of consolidated net income attributable to the parent and noncontrolling interest on the consolidated statement of operations. If a subsidiary is deconsolidated, any retained noncontrolling equity investment in the former subsidiary must be measured at fair value, and a gain or loss must be recognized in net income based on such fair value.

PG&E Corporation has reclassified its noncontrolling interest in the Utility from Preferred Stock of Subsidiaries to equity in PG&E Corporation's Consolidated Financial Statements in accordance with SFAS No. 160 for all periods presented. The Utility had no material noncontrolling interests in consolidated subsidiaries as of December 31, 2009 and December 31, 2008.

PG&E Corporation and the Utility applied the presentation and disclosure requirements of SFAS No. 160 retrospectively. Other than the change in presentation of noncontrolling interests, adoption of SFAS No. 160 did not have a material impact on PG&E Corporation's or the Utility's Consolidated Financial Statements.

Subsequent Events

On June 30, 2009, PG&E Corporation and the Utility adopted SFAS No. 165, "Subsequent Events" ("SFAS No. 165"), which is codified in the Subsequent Events Topic of the FASB ASC. SFAS No. 165 does not significantly change the prior accounting practice for subsequent events, except for the requirement to disclose the date through which an entity has evaluated subsequent events and the basis for that date. PG&E Corporation and the Utility have evaluated material subsequent events through February 19, 2010, the issue date of PG&E Corporation's and the Utility's Consolidated Financial Statements. Other than this disclosure, adoption of SFAS No. 165 did not have a material impact on PG&E Corporation's or the Utility's Consolidated Financial Statements.

Recognition and Presentation of Other-Than-Temporary Impairments

On June 30, 2009, PG&E Corporation and the Utility adopted FASB Staff Position ("FSP") SFAS 115-2 and SFAS

124-2, "Recognition and Presentation of Other-Than-Temporary Impairments," which is codified in the Investments – Debt and Equity Securities Topic of the FASB ASC. Under this FSP, to assess whether an other-than-temporary impairment exists for a debt security, an entity must (1) evaluate the likelihood of liquidating the debt security prior to recovering its cost basis, and (2) determine if any impairment of the debt security is related to credit losses. In addition, this FSP requires enhanced disclosures of other-than-temporary impairments on debt and equity securities in the financial statements. However, this FSP does not amend recognition and measurement guidance for other-than-temporary impairments of equity securities. Adoption of this FSP did not have a material impact on PG&E Corporation's or the Utility's Consolidated Financial Statements.

Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly

On June 30, 2009, PG&E Corporation and the Utility adopted FSP SFAS 157-4, "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly," which is codified in the Fair Value Measurements and Disclosures Topic of the FASB ASC. This FSP provides guidance on estimating fair value when the volume or the level of activity for an asset or a liability has significantly decreased or when transactions are not orderly when compared with normal market conditions. In particular, this FSP calls for adjustments to quoted prices or historical transaction data when estimating fair value in such circumstances. This FSP also provides guidance to identify such circumstances. Furthermore, this FSP requires fair value measurement disclosures made pursuant to the Fair Value Measurements and Disclosures Topic of the FASB ASC to be categorized by major security type (i.e., based on the nature and risks of the security). (See Note 11 of the Notes to the Consolidated Financial Statements.) Other than this change, adoption of this FSP did not have a material impact on PG&E Corporation's or the Utility's Consolidated Financial Statements.

Topic 105: Generally Accepted Accounting Principles — amendments based on Statement of Financial Accounting Standards No. 168 — The FASB Accounting Standards Codification™ and the Hierarchy of Generally Accepted Accounting Principles

On July 1, 2009, PG&E Corporation and the Utility adopted Accounting Standards Update ("ASU") No. 2009-01, "Topic 105: Generally Accepted Accounting Principles – amendments based on Statement of Financial Accounting Standards No. 168 – *The FASB Accounting Standards Codification*™ and the Hierarchy of Generally Accepted Accounting Principles" ("ASU No. 2009-01"). ASU No. 2009-01 re-defines authoritative GAAP for nongovernmental entities to comprise only the FASB ASC and, for SEC registrants, guidance issued by the SEC. The FASB ASC is a reorganization and compilation of all then-existing authoritative GAAP for nongovernmental entities, except for guidance issued by the SEC. The FASB ASC is amended to effect non-SEC changes to authoritative GAAP. Adoption of ASU No. 2009-01 only changed the referencing convention of GAAP in PG&E Corporation's and the Utility's Consolidated Financial Statements.

Employers' Disclosures about Postretirement Benefit Plan Assets

On December 31, 2009, PG&E Corporation and the Utility adopted FSP SFAS 132(R)-1, "Employers' Disclosures about Postretirement Benefit Plan Assets," which is codified in the Compensation – Retirement Benefits Topic of the FASB ASC. This FSP amends and expands the disclosure requirements of that Topic. In particular, this FSP requires an entity to provide qualitative disclosures about how investment allocation decisions are made, the inputs and valuation techniques used to measure the fair value of plan assets, and the concentration of risk within plan assets. In addition, this FSP requires quantitative disclosures showing the fair value of each major category of plan assets, the levels in which each asset is classified within the fair value hierarchy, and a reconciliation for the period of plan assets that are measured using significant unobservable inputs. This FSP only applies to annual reporting periods. (See Note 13 of the Notes to the Consolidated Financial Statements.)

ACCOUNTING PRONOUNCEMENTS ISSUED BUT NOT YET ADOPTED

Transfers and Servicing (Topic 860) — Accounting for Transfers of Financial Assets

In December 2009, the FASB issued ASU No. 2009-16, "Transfers and Servicing (Topic 860)–Accounting for Transfers of Financial Assets" ("ASU No. 2009-16"). ASU No. 2009-16 eliminates the concept of a qualifying special-purpose entity and clarifies the requirements for derecognizing a financial asset and for applying sale accounting to a transfer of a financial asset. In addition, ASU No. 2009-16 requires an entity to disclose more information about transfers of financial assets; the entity's continuing involvement, if any, with transferred financial assets; and the entity's continuing risks, if any, from transferred financial assets. ASU No. 2009-16 is effective prospectively for PG&E Corporation and the Utility beginning on January 1, 2010. PG&E Corporation and the Utility are currently evaluating the impact of ASU No. 2009-16.

Consolidations (Topic 810) — Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities

In December 2009, the FASB issued ASU No. 2009-17, "Consolidations (Topic 810)–Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities" ("ASU No. 2009-17"). ASU No. 2009-17 amends the Consolidation Topic of the FASB ASC regarding when and how to determine, or re-determine, whether an entity is a VIE. In addition, ASU No. 2009-17 replaces the Consolidation Topic of the FASB ASC's quantitative approach for determining who has a controlling financial interest in a VIE with a qualitative approach. Furthermore, ASU No. 2009-17 requires ongoing assessments of whether an entity is the primary beneficiary of a VIE. ASU No. 2009-17 is effective prospectively for PG&E Corporation and the Utility beginning on January 1, 2010. PG&E Corporation and the Utility are currently evaluating the impact of ASU No. 2009-17.

Fair Value Measurements and Disclosures (Topic 820) — Improving Disclosures about Fair Value Measurements

In January 2010, the FASB issued ASU No. 2010-06, "Fair Value Measurements and Disclosures (Topic 820)–Improving Disclosures about Fair Value Measurements" ("ASU No. 2010-06"). ASU No. 2010-06 requires additional disclosures regarding (1) transfers into and out of Levels 1 and 2 of the fair value hierarchy, and (2) fair value measurement inputs and techniques. In addition, ASU No. 2010-06 clarifies that fair value measurement disclosures and postretirement benefit plan asset disclosures should be disaggregated beyond the line items in the balance sheet. These new disclosures and this clarification are effective prospectively for PG&E Corporation and the Utility beginning on January 1, 2010. Furthermore, ASU No. 2010-06 modifies, from a net basis to a gross basis, the presentation of purchases, sales, issuances, and settlements in the disclosure of activity in Level 3 of the fair value hierarchy. This modification is effective prospectively for PG&E Corporation and the Utility beginning on January 1, 2011. PG&E Corporation and the Utility are currently evaluating the impact of ASU No. 2010-06.

NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

REGULATORY ASSETS

Current Regulatory Assets

At December 31, 2009 and 2008, the Utility had current regulatory assets of $427 million and $355 million, respectively, consisting primarily of the current portion of price risk management regulatory assets. Price risk management regulatory assets represent the deferral of unrealized losses related to price risk management derivative instruments with terms of less than one year. (See Note 10 of the Notes to the Consolidated Financial Statements for further discussion.) Current regulatory assets are included in Prepaid expenses and other in the Consolidated Balance Sheets.

Long-Term Regulatory Assets

Long-term regulatory assets are composed of the following:

	Balance at December 31,	
(in millions)	**2009**	2008
Pension benefits	**$1,386**	$1,624
Energy recovery bonds	**1,124**	1,487
Deferred income tax	**1,027**	847
Utility retained generation	**737**	799
Environmental compliance costs	**408**	385
Price risk management	**346**	362
Unamortized loss, net of gain, on reacquired debt	**203**	225
Other	**291**	267
Total long-term regulatory assets	**$5,522**	$5,996

The regulatory asset for pension benefits represents the cumulative differences between amounts recognized for ratemaking purposes and amounts recognized in accordance with GAAP, which also includes amounts that otherwise would be fully recorded to Accumulated other comprehensive loss in the Consolidated Balance Sheets. (See Note 13 of the Notes to the Consolidated Financial Statements for further discussion.)

The regulatory asset for energy recovery bonds ("ERB") represents the refinancing of the regulatory asset provided for in the settlement agreement entered into between PG&E Corporation, the Utility, and the CPUC in 2003 to resolve the Utility's proceeding under Chapter 11 ("Chapter 11 Settlement Agreement"). (See Note 5 of the Notes to the Consolidated Financial Statements for further discussion of the ERBs.) The regulatory asset is amortized over the life of the bonds consistent with the period over which the related billed revenues and bond-related expenses are recognized. The Utility expects to fully recover this asset by the end of 2012 when the ERBs mature.

The regulatory assets for deferred income taxes represent deferred income tax benefits previously passed through to customers offset by deferred income tax liabilities. The CPUC requires the Utility to pass through certain tax benefits to customers, ignoring the effect of deferred taxes on rates. Based on current regulatory ratemaking and income tax laws, the Utility expects to recover deferred income taxes related to regulatory assets over periods ranging from 1 to 45 years. (See Note 9 of the Notes to the Consolidated Financial Statements for a discussion of income taxes.)

In connection with the Chapter 11 Settlement Agreement, the CPUC authorized the Utility to recover $1.2 billion of costs related to the Utility's retained generation assets. The individual components of these regulatory assets are amortized over the respective lives of the underlying generation facilities, consistent with the period over which the related revenues are recognized. The weighted average remaining life of the assets is 16 years.

The regulatory assets for environmental compliance costs represent the portion of estimated environmental remediation expense that the Utility expects to recover in future rates as actual remediation costs are incurred. The Utility expects to recover these costs over the next 30 years. (See Note 16 of the Notes to the Consolidated Financial Statements.)

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

The regulatory assets for unamortized loss, net of gain, on reacquired debt represent 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 17 years, and these costs will be fully recovered by 2026.

At December 31, 2009, "Other" consisted of regulatory assets relating to ARO expenses recorded in accordance with GAAP, which are probable of future recovery through the ratemaking process, and removal costs associated with the replacement of the steam generators in the Utility's two nuclear generating units at the Diablo Canyon Power Plant ("Diablo Canyon"), as approved by the CPUC for future recovery. At December 31, 2009 and 2008, "Other" also consisted of costs that the Utility incurred in terminating a 30-year power purchase agreement, which are being amortized and collected in rates through September 2014, as well as costs incurred in relation to the Utility's plan of reorganization under Chapter 11 that became effective in April 2004.

In general, the Utility does not earn a return on regulatory assets in which 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.

REGULATORY LIABILITIES

Current Regulatory Liabilities

At December 31, 2009 and 2008, the Utility had current regulatory liabilities of $163 million and $313 million, respectively, primarily consisting of the current portion of price risk management regulatory liabilities. Current regulatory liabilities are included in Current Liabilities – Other in the Consolidated Balance Sheets.

Long-Term Regulatory Liabilities

Long-term regulatory liabilities are composed of the following:

	Balance at December 31,	
(in millions)	**2009**	2008
Cost of removal obligation	**$2,933**	$2,735
Public purpose programs	**508**	442
Recoveries in excess of ARO	**488**	226
Other	**196**	254
Total long-term regulatory liabilities	**$4,125**	$3,657

The regulatory liability for the Utility's cost of removal obligations represents differences between amounts collected in rates for asset removal costs and the asset removal costs recorded in accordance with GAAP.

The regulatory liability for public purpose programs represents amounts received from customers designated for public purpose program costs that are expected to be incurred in the future. For example, these regulatory liabilities include revenues collected from customers to pay for costs that the Utility expects to incur in the future under the California Solar Initiative to promote the use of solar energy in residential homes and commercial, industrial, and agricultural properties.

The regulatory liability for recoveries in excess of ARO represents differences between amounts collected in rates for decommissioning the Utility's nuclear power facilities and the ARO expenses recorded in accordance with GAAP. Decommissioning costs recovered in rates are placed in nuclear decommissioning trusts. The regulatory liability for recoveries in excess of ARO also represents the deferral of realized and unrealized gains and losses on those nuclear decommissioning trust assets.

"Other" at December 31, 2009 and 2008 included the deferral of unrealized gains related to price risk management derivative instruments with terms in excess of one year, the gain associated with the Utility's acquisition of the permits and other assets related to the Gateway Generating Station as part of a settlement that the Utility entered with Mirant Corporation, as well as costs incurred for hazardous substance remediation.

REGULATORY BALANCING ACCOUNTS

The Utility uses regulatory balancing accounts to accumulate differences between actual billed and unbilled revenues and the Utility's authorized revenue requirements for the period. The Utility also uses regulatory balancing accounts to accumulate differences between incurred costs and actual billed and unbilled revenues, as well as differences between incurred costs and authorized revenue meant to recover those costs. Under-collections that are probable of recovery through regulated rates are recorded as regulatory balancing account assets. Over-collections that are probable of being credited to customers are recorded as regulatory balancing account liabilities.

The Utility's current regulatory balancing accounts represent the amount expected to be refunded to or received from the Utility's customers through authorized rate adjustments within the next 12 months. Regulatory balancing accounts that the Utility does not expect to collect or refund in the next 12 months are included in Other Noncurrent Assets – Regulatory assets and Noncurrent Liabilities – Regulatory liabilities in the Consolidated Balance Sheets.

Current Regulatory Balancing Accounts, net

	Receivable (Payable)	
	Balance at December 31,	
(in millions)	**2009**	2008
Utility generation	**$ 355**	$ 164
Distribution revenue adjustment mechanism	**152**	40
Energy procurement costs	**128**	598
Gas fixed cost	**93**	60
Transmission revenue	**46**	173
Public purpose programs	**(5)**	(263)
Energy recovery bonds	**(185)**	(231)
Other	**244**	(74)
Total regulatory balancing accounts, net	**$ 828**	$ 467

The utility generation balancing account is used to record and recover the authorized revenue requirements associated with Utility-owned electric generation, including capital and related non-fuel operating and maintenance expenses. The Utility's recovery of these revenue requirements is independent, or "decoupled," from the volume of sales; therefore, the Utility recognizes revenue evenly over the year, even though the level of cash collected from customers will fluctuate depending on the volume of electricity sales. During periods of more temperate weather, there is generally an under-collection in this balancing account due to lower electricity sales and lower rates. During the warmer months of summer, the under-collection generally decreases due to higher rates and electric usage that cause an increase in generation revenues. At December 31, 2009, the under-collection was impacted by lower than expected electricity sales and an increase in revenue requirements related to the construction of the Gateway Generating Station and the replacement of steam generators at Diablo Canyon Unit 1.

The distribution revenue adjustment mechanism balancing account is used to record and recover the authorized electric distribution revenue requirements and certain other electric distribution-related authorized costs. The Utility recognizes revenue evenly over the year even though the level of cash collected from customers will fluctuate depending on the volume of electricity sales. During periods of more temperate weather, there is generally an under-collection in this balancing account due to lower electricity sales and lower rates. During the warmer months of summer, the under-collection generally decreases due to higher rates and electric usage that cause an increase in distribution revenues. At December 31, 2009, there was an under-collection due to lower than expected electricity sales.

The Utility is generally authorized to recover 100% of its prudently incurred electric fuel and energy procurement costs. The Utility tracks energy procurement costs in balancing accounts and files annual forecasts of energy procurement costs that it expects to incur during the following year, and rates are set to recover such expected costs.

The gas fixed cost balancing account is used to track the recovery of CPUC-authorized gas distribution revenue requirements and certain other gas distribution-related costs. The under-collection or over-collection position of this account is dependent on seasonality and volatility in gas volumes.

The transmission revenue balancing account represents the difference between electric transmission wheeling revenues received by the Utility from the California Independent System Operator ("CAISO") (on behalf of electric transmission wholesale customers) and refunds to customers plus interest.

The public purpose programs balancing accounts primarily track the recovery of the authorized public purpose program revenue requirement and the actual cost of such programs. The public purpose programs primarily consist of the energy efficiency programs; low-income energy efficiency programs; research, development, and demonstration programs; and renewable energy programs. A refund of $230 million from the California Energy Commission for unspent renewable program funding received during 2008 was returned to customers through lower rates throughout 2009.

The ERBs balancing account records certain benefits and costs associated with ERBs that are provided to, or received from, customers. In addition, this account ensures that customers receive the benefits of the net amount of energy supplier refunds, claim offsets, and other credits received by the Utility after the second series of ERBs were issued.

At December 31, 2009 and 2008, "Other" included the California Alternate Rates for Energy balancing account, which records the revenue shortfall associated with the low-income customer assistance program. Participation in the program is generally impacted by economic conditions. Program spending increases as more customers participate in the programs, resulting in an under-collection. "Other" also included incentive awards earned by the Utility for implementing customer energy efficiency programs.

NOTE 4: DEBT

LONG-TERM DEBT

The following table summarizes PG&E Corporation's and the Utility's long-term debt:

	December 31,	
(in millions)	**2009**	2008
PG&E Corporation		
Convertible subordinated notes, 9.50%, due 2010	**$ 247**	$ 280
Less: current portion	**(247)**	–
Total convertible subordinated notes	**–**	280
Senior notes, 5.75%, due 2014	**350**	–
Unamortized discount	**(2)**	–
Total senior notes	**348**	–
Total PG&E Corporation long-term debt, net of current portion	**348**	280
Utility		
Senior notes:		
3.60% due 2009	**–**	600
4.20% due 2011	**500**	500
6.25% due 2013	**400**	400
4.80% due 2014	**1,000**	1,000
5.625% due 2017	**700**	700
8.25% due 2018	**800**	800
6.05% due 2034	**3,000**	3,000
5.80% due 2037	**700**	700
6.35% due 2038	**400**	400
6.25% due 2039	**550**	–
5.40% due 2040	**550**	–
Less: current portion	**–**	(600)
Unamortized discount, net of premium	**(35)**	(22)
Total senior notes	**8,565**	7,478
Pollution control bonds:		
Series 1996 C, E, F, 1997 B, variable rates(1), due 2026(2)	**614**	614
Series 1996 A, 5.35%, due 2016	**200**	200
Series 2004 A–D, 4.75%, due 2023	**345**	345
Series 2008 A–D, variable rates, due 2016 and 2026	**–**	309
Series 2008 G and F, 3.75%(3), due 2018 and 2026	**95**	95
Series 2009 A–D, variable rates(4), due 2016 and 2026(5)	**309**	–
Less: current portion	**(95)**	–
Total pollution control bonds	**1,468**	1,563
Total Utility long-term debt, net of current portion	**10,033**	9,041
Total consolidated long-term debt, net of current portion	**$10,381**	$9,321

(1) At December 31, 2009, interest rates on these bonds and the related loans ranged from 0.20% to 0.25%.

(2) Each series of these bonds is supported by a separate letter of credit that expires on February 26, 2012. Although the stated maturity date is 2026, each series will remain outstanding only if the Utility extends or replaces the letter of credit related to the series or otherwise obtains a consent from the issuer to the continuation of the series without a credit facility.

(3) These bonds bear interest at 3.75% per year through September 19, 2010; are subject to mandatory tender on September 20, 2010; and may be remarketed in a fixed or variable rate mode.

(4) At December 31, 2009, interest rates on these bonds and the related loans ranged from 0.18% to 0.24%.

(5) Each series of these bonds is supported by a separate direct-pay letter of credit that expires on October 29, 2011. The Utility may choose to provide a substitute letter of credit for any series of these bonds, subject to a rating requirement.

PG&E CORPORATION

Senior Notes

On March 12, 2009, PG&E Corporation issued $350 million principal amount of 5.75% Senior Notes due April 1, 2014. The PG&E Corporation senior notes are unsecured and rank equally with the other senior unsecured and unsubordinated debt.

Convertible Subordinated Notes

At December 31, 2009, PG&E Corporation had outstanding $247 million of 9.50% Convertible Subordinated Notes that are scheduled to mature on June 30, 2010. These Convertible Subordinated Notes may be converted (at the option of the holder) at any time prior to maturity into 16,370,789 shares of PG&E Corporation common stock, at a conversion price of $15.09 per share. The conversion price is subject to adjustment for significant changes in the number of outstanding shares of PG&E Corporation's common stock.

In addition, holders of the Convertible Subordinated Notes are entitled to receive "pass-through dividends" determined by multiplying the cash dividend paid by PG&E Corporation per share of common stock by a number equal to the principal amount of the Convertible Subordinated Notes divided by the conversion price. During 2009, PG&E Corporation paid $28 million of pass-through dividends to the holders of Convertible Subordinated Notes. On January 15, 2010, PG&E Corporation paid $7 million of pass-through dividends. The dividend participation rights of the Convertible Subordinated Notes are considered to be embedded derivative instruments and, therefore, must be bifurcated from the Convertible Subordinated Notes and recorded at fair value in PG&E Corporation's Consolidated Financial Statements. The payment of pass-through dividends is recognized as an operating cash flow in PG&E Corporation's Consolidated Statements of Cash Flows. Changes in the fair value are recognized in PG&E

Corporation's Consolidated Statements of Income as a non-operating expense or income (in Other income (expense), net). (See Notes 10 and 11 of the Notes to the Consolidated Financial Statements for further discussion of these instruments.)

On January 13, 2009, PG&E Corporation, upon request by an investor, converted $28 million of Convertible Subordinated Notes into 1,855,865 shares, at the conversion price of $15.09 per share. Additionally, on July 1, 2009, PG&E Corporation, upon request by an investor, converted $5 million of Convertible Subordinated Notes into 331,404 shares, at the conversion price of $15.09 per share.

UTILITY

Senior Notes

At December 31, 2009, the Utility had outstanding $8.6 billion of senior notes with various interest rates and maturity dates, including the following issuances made during 2009.

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

On June 11, 2009, the Utility issued $500 million principal amount of Floating Rate Senior Notes due June 10, 2010. The interest rate for the Floating Rate Senior Notes is equal to the three-month London Interbank Offered Rate plus 0.95% and resets quarterly. At December 31, 2009, the interest rate on the Floating Rate Senior Notes was 1.21%.

On November 18, 2009, the Utility issued $550 million principal amount of 5.40% Senior Notes due January 15, 2040.

The Utility's senior notes are unsecured and rank equally with the Utility's other senior unsecured and unsubordinated debt. Under the indenture for the senior notes, the Utility has agreed that it will not incur secured debt or engage in sales leaseback transactions (except for (1) debt secured by specified liens, and (2) aggregate other secured debt and sales and leaseback transactions not exceeding 10% of the Utility's net tangible assets, as defined in the indenture) unless the Utility provides that the senior notes will be equally and ratably secured.

Pollution Control Bonds

The California Pollution Control Financing Authority and the California Infrastructure and Economic Development Bank have issued various series of tax-exempt pollution control bonds for the benefit of the Utility. Under the pollution control bond loan agreements related to the Series 1996 A bonds, the Series 2004 A–D bonds, and the Series 2008 F and G bonds, 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. With respect to the Series 1996 C, E, and F bonds; the Series 1997 B bonds; and the Series 2009 A–D bonds, the Utility reimburses the letter of credit providers for their payments to the trustee for these bonds, or if a letter of credit provider fails to pay under its respective letter of credit, the Utility is obligated to pay the principal; premium, if any; and interest on those bonds. All payments on the Series 1996 C, E, and F bonds; the Series 1997 B bonds; and the Series 2009 A–D bonds are made through draws on separate direct-pay letters of credit for each series issued by a financial institution.

All of the pollution control bonds were used to finance or refinance pollution control facilities at the Geysers geothermal power plant or at the Utility's Diablo Canyon nuclear power plant and were issued as "exempt facility bonds" within the meaning of Section 142(a) of the Internal Revenue Code of 1954, as amended ("Code"). The Utility agrees not to take any action or fail to take any action if any such action or inaction would cause the interest on the bonds to be taxable or to be other than exempt facility bonds.

In 1999, the Utility sold the Geysers geothermal power plant to Geysers Power Company, LLC pursuant to purchase and sale agreements stating that Geysers Power Company, LLC will use the bond-financed facilities solely as pollution control facilities within the meaning of Section 103(b)(4)(F) of the Code. Although Geysers Power Company, LLC subsequently filed a petition for reorganization under Chapter 11, it assumed the purchase and sale agreements under its Chapter 11 plan of reorganization that became effective on January 31, 2008. The Utility has no knowledge that Geysers Power Company, LLC intends to cease using the bond-financed facilities solely as pollution control bonds facilities within the meaning of Section 103(b)(4)(F) of the Code.

The Utility has obtained credit support from insurance companies for the Series 1996 A bonds and the Series 2004 A–D bonds such that if the Utility does not pay the principal and interest on any series of these insured bonds, the bond insurer for that series will pay the principal and interest.

On September 1, 2009, the California Infrastructure and Economic Development Bank issued $149 million of tax-exempt pollution control bonds series 2009 A and B due on November 1, 2026 and $160 million of tax-exempt pollution control bonds series 2009 C and D due on December 1, 2016. The proceeds were used to repurchase the corresponding series of 2008 pollution control bonds. The 2009 A–D bonds, issued at par with an initial rate of 0.20%, are variable rate demand notes with interest resetting daily and backed by direct-pay letters of credit. Unlike the series 2008 bonds, interest earned on the series 2009 bonds is not subject to the alternative minimum tax. A provision in the American Recovery and Reinvestment Act of 2009 allows certain tax-exempt bonds that are subject to the alternative minimum tax to be reissued or refunded in 2009 or 2010 as tax-exempt bonds that are not subject to the alternative minimum tax. As a result, the 2009 A–D bonds were issued at a lower interest rate, reducing the Utility's interest expense.

REPAYMENT SCHEDULE

PG&E Corporation's and the Utility's combined aggregate principal repayment amounts of long-term debt at December 31, 2009 are reflected in the table below:

(in millions, except interest rates)	2010	2011	2012	2013	2014	Thereafter	Total
Long-term debt:							
PG&E Corporation							
Average fixed interest rate	9.50%	–	–	–	5.75%	–	7.30%
Fixed rate obligations	$ 247	–	–	–	$ 350	–	$ 597
Utility							
Average fixed interest rate	3.75%	4.20%	–	6.25%	4.80%	6.13%	
Fixed rate obligations	$ 95	$ 500	–	$ 400	$1,000	$7,245	$ 9,240
Variable interest rate as of December 31, 2009	–	0.21%	0.21%	–	–	–	0.21%
Variable rate obligations	–	$ 309(1)	$ 614(2)	–	–	–	$ 923
Less: current portion	(342)	–	–	–	–	–	(342)
Total consolidated long-term debt	$ –	$ 809	$ 614	$ 400	$1,350	$7,245	$10,418

(1) These bonds, due from 2016 through 2026, are backed by a direct-pay letter of credit that expires on October 29, 2011. The bonds will be subject to a mandatory redemption unless the letter of credit is extended or replaced or the issuer consents to the continuation of these series without a credit facility. Accordingly, the bonds have been classified for repayment purposes in 2011.

(2) The $614 million pollution control bonds, due in 2026, are backed by letters of credit that expire on February 26, 2012. 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 2012.

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, 2009:

(in millions)							At December 31, 2009
Authorized Borrower	Facility	Termination Date	Facility Limit	Letters of Credit Outstanding	Cash Borrowings	Commercial Paper Backup	Availability
PG&E Corporation	Revolving credit facility	February 2012	$ 187(1)	$ –	$–	N/A	$ 187
Utility	Revolving credit facility	February 2012	1,940(2)	252	–	$ 333	1,355
Total credit facilities			$2,127	$252	$–	$ 333	$1,542

(1) Includes an $87 million sublimit for letters of credit and a $100 million sublimit for "swingline" loans, defined as loans that are made available on a same-day basis and are repayable in full within 30 days.

(2) Includes a $921 million sublimit for letters of credit and a $200 million sublimit for swingline loans.

PG&E CORPORATION

Revolving credit facility

PG&E Corporation has a $187 million revolving credit facility with a syndicate of lenders that expires on February 26, 2012. PG&E Corporation amended its revolving credit facility on April 27, 2009 to remove Lehman Brothers Bank, FSB ("Lehman Bank") as a lender. Prior to the amendment, the total borrowing capacity under the revolving credit facility was $200 million, including a commitment from Lehman Bank that represented $13 million, or 7%, of the total. Borrowings under the revolving 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 revolving 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 that certain conditions are met. The fees and interest rates that PG&E Corporation pays under the revolving credit facility vary depending on the Utility's unsecured debt ratings issued by Standard & Poor's ("S&P") ratings service and Moody's Investors Service ("Moody's").

The revolving 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 revolving credit facility, discussed below. In addition, the revolving 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. At December 31, 2009, PG&E Corporation met both of these tests.

UTILITY

Revolving credit facility

The Utility has a $1.94 billion revolving credit facility with a syndicate of lenders that expires on February 26, 2012. The Utility amended its revolving credit facility on April 27, 2009 to remove Lehman Bank as a lender. Prior to the amendment, the total borrowing capacity under the revolving credit facility was $2.0 billion, including a commitment from Lehman Bank that represented $60 million, or 3%, of the total. Borrowings under the revolving credit facility and letters of credit are used primarily for liquidity and to provide credit enhancements to counterparties for natural gas and energy procurement transactions. The Utility treats the amount of its outstanding commercial paper as a reduction to the amount available under its revolving credit facility so that liquidity from the revolving credit facility is available to repay outstanding commercial paper.

The revolving credit 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 revolving credit 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, 2009, the Utility met this ratio test.

Commercial Paper Program

The Utility has a $1.75 billion commercial paper program, the borrowings from which are used primarily to cover fluctuations in cash flow requirements. Liquidity support for these borrowings is provided by available capacity under the Utility's revolving credit facility, as described above. The commercial paper may have maturities up to 365 days and ranks equally with the Utility's other unsubordinated and unsecured indebtedness. Commercial paper notes are sold at an interest rate dictated by the market at the time of issuance. At December 31, 2009, the average yield was 0.31%.

NOTE 5: ENERGY RECOVERY BONDS

In 2005, PG&E Energy Recovery Funding, LLC ("PERF"), a wholly owned consolidated subsidiary of the Utility, issued two separate series of ERBs in the aggregate amount of $2.7 billion to refinance a regulatory asset that the Utility recorded in connection with the Chapter 11 Settlement Agreement. The proceeds of the ERBs were used by PERF to purchase from the Utility the right, known as "recovery property," to be paid a specified amount from a dedicated rate component ("DRC") to be collected from the Utility's electricity customers. 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 principal, interest, and miscellaneous expenses associated with the bonds.

The first series of ERBs issued on February 10, 2005 included five classes aggregating to a $1.9 billion principal amount with scheduled maturities ranging from September 25, 2006 to December 25, 2012. Interest rates on the remaining three outstanding classes range from 4.14% for the earliest maturing class to 4.47% for the latest maturing class. The proceeds of the first series of ERBs were paid by PERF to the Utility and were used by the Utility to refinance the remaining unamortized after-tax balance of the settlement regulatory asset. The second series of ERBs, issued on November 9, 2005, included three classes aggregating to an $844 million principal amount, with scheduled maturities ranging from June 25, 2009 to December 25, 2012. Interest rates on the remaining two classes are 5.03% for the earliest maturing class and 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 charges from customers.

The total amount of ERB principal outstanding was $1.2 billion at December 31, 2009 and $1.6 billion at December 31, 2008. The scheduled principal repayments for ERBs are reflected in the table below:

(in millions)	2010	2011	2012	Total
Utility				
Average fixed interest rate	4.49%	4.59%	4.66%	4.58%
Energy recovery bonds	$ 386	$ 404	$ 423	$1,213

While PERF is a wholly owned consolidated subsidiary of the Utility, it is legally separate from the Utility. The assets (including the recovery property) of PERF are not available to creditors of the Utility or PG&E Corporation, and the recovery property is not legally an asset of the Utility or PG&E Corporation.

NOTE 6: COMMON STOCK

PG&E CORPORATION

PG&E Corporation has authorized 800 million shares of no-par common stock, of which 371,272,457 shares were issued and outstanding at December 31, 2009 and 362,346,685 shares were issued and outstanding at December 31, 2008.

Of the 371,272,457 shares issued and outstanding at December 31, 2009, 670,552 shares were granted as restricted stock as share-based compensation awarded under the PG&E Corporation Long-Term Incentive Program and the 2006 Long-Term Incentive Plan (“2006 LTIP”), and 6,773,290 shares were issued upon the exercise of employee stock options, for the account of 401(k) plan participants, and to participants in the Dividend Reinvestment and Stock Purchase Plan (“DRSPP”). (See Note 13 of the Notes to the Consolidated Financial Statements.) In addition, 2,187,269 shares were issued upon the conversion of Convertible Subordinated Notes. (See Note 4 of the Notes to the Consolidated Financial Statements.)

UTILITY

The Utility is authorized to issue 800 million shares of its $5 par value common stock, of which 264,374,809 shares were issued and outstanding as of December 31, 2009 and 2008. As of December 31, 2009, PG&E Corporation held all of the Utility’s outstanding common stock.

The Utility may pay common stock dividends and repurchase its common stock provided that cumulative preferred dividends on its preferred stock are paid.

DIVIDENDS

During 2009, the Utility paid common stock dividends totaling $624 million to PG&E Corporation. During 2009, PG&E Corporation paid common stock dividends of $1.65 per share, totaling $590 million, net of $17 million that was reinvested in additional shares of common stock by participants in the DRSPP. On December 16, 2009, the Board of Directors of PG&E Corporation declared a quarterly dividend of $0.42 per share, totaling $157 million, which was paid on January 15, 2010 to shareholders of record on December 31, 2009.

During 2008, the Utility paid common stock dividends totaling $589 million, including $568 million of common stock dividends paid to PG&E Corporation and $21 million paid to PG&E Holdings, LLC. During 2008, PG&E Corporation paid common stock dividends of $1.53 per share, totaling $554 million, net of $20 million that was reinvested in additional shares of common stock by participants in the DRSPP, and including $28 million that was paid to Elm Power Corporation.

During 2007, the Utility paid common stock dividends of $547 million, including $509 million of common stock dividends paid to PG&E Corporation and $38 million paid to PG&E Holdings, LLC. During 2007, PG&E Corporation paid common stock dividends of $1.41 per share totaling $526 million, net of $5 million that was reinvested in additional shares of common stock by participants in the DRSPP, and including $35 million that was paid to Elm Power Corporation.

Effective August 29, 2008, PG&E Holdings, LLC, and Elm Power Corporation, wholly owned subsidiaries of the Utility and PG&E Corporation, respectively, were dissolved, and the shares of each entity were subsequently cancelled.

PG&E Corporation and the Utility each have a revolving credit facility that requires the company to maintain a ratio of consolidated total debt to consolidated capitalization of at most 65%. In addition, the CPUC requires the Utility to maintain a capital structure composed of at least 52% equity on average each year from 2008 through 2010. These requirements are considered to be restrictions on the payment of dividends since neither company can declare dividends if the resulting decrease in retained earnings would cause the ratio of consolidated total debt to consolidated capitalization to exceed 65% or the Utility's capital structure to fall below 52% equity. Based on the calculation of these ratios for each company, no amount of PG&E Corporation's retained earnings and $2.5 billion of the Utility's retained earnings were restricted at December 31, 2009.

In addition, the Utility was required to maintain at least $6.6 billion of its net assets as equity in order to maintain the capital structure of at least 52% equity at December 31, 2009. As a result, $6.6 billion of the Utility's net assets are restricted and may not be transferred to PG&E Corporation in the form of cash dividends.

NOTE 7: PREFERRED STOCK

PG&E CORPORATION

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 to date.

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. All remaining shares of preferred stock may be issued as redeemable or nonredeemable preferred stock.

The following table summarizes the Utility's issued and outstanding preferred stock without mandatory redemption provisions at December 31, 2009 and 2008:

(in millions, except share amounts and redemption price)	Shares Outstanding	Redemption Price	Balance
Nonredeemable $25 par value preferred stock			
5.00% Series	400,000		$ 10
5.50% Series	1,173,163		30
6.00% Series	4,211,662		105
Total nonredeemable preferred stock	5,784,825		$145
Redeemable $25 par value preferred stock			
4.36% Series	418,291	$25.75	$ 11
4.50% Series	611,142	26.00	15
4.80% Series	793,031	27.25	20
5.00% Series	1,778,172	26.75	44
5.00% Series A	934,322	26.75	23
Total redeemable preferred stock	4,534,958		$113

Holders of the Utility's nonredeemable preferred stock have rights to annual dividends ranging from $1.25 to $1.50 per share. The Utility's redeemable 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, 2009, annual dividends on redeemable preferred stock ranged from $1.09 to $1.25 per share.

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. During the years ended December 31, 2009, 2008, and 2007, the Utility paid $14 million of dividends on preferred stock without mandatory redemption provisions. On December 16, 2009, the Board of Directors of the Utility declared a cash dividend on its outstanding series of preferred stock totaling $4 million that was paid on February 15, 2010 to preferred shareholders of record on January 29, 2010. 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.

NOTE 8: EARNINGS PER SHARE

Earnings per common share ("EPS") is calculated utilizing the "two-class" method, by dividing the sum of distributed earnings to common shareholders and undistributed earnings allocated to common shareholders by the weighted average number of common shares outstanding during the period. In applying the two-class method, undistributed earnings are allocated to both common shares and participating securities. PG&E Corporation's 9.5% Convertible Subordinated Notes are entitled to receive pass-through dividends and meet the criteria of participating securities. All of the participating securities participate in dividends on a 1:1 basis with shares of common stock.

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

	Year Ended December 31,		
(in millions, except per share amounts)	**2009**	2008	2007
Basic			
Income Available for Common Shareholders	**$1,220**	$1,338	$1,006
Less: distributed earnings to common shareholders	**621**	560	508
Undistributed earnings	**599**	778	498
Less: undistributed earnings from discontinued operations	**–**	154	–
Undistributed earnings from continuing operations	**$ 599**	$ 624	$ 498
Allocation of undistributed earnings to common shareholders			
Distributed earnings to common shareholders	**$ 621**	$ 560	$ 508
Undistributed earnings allocated to common shareholders – continuing operations	**573**	592	472
Undistributed earnings allocated to common shareholders – discontinued operations	**–**	146	–
Total common shareholders earnings	**$1,194**	$1,298	$ 980
Weighted average common shares outstanding, basic	**368**	357	351
Convertible subordinated notes	**17**	19	19
Weighted average common shares outstanding and participating securities	**385**	376	370
Net earnings per common share, basic			
Distributed earnings, basic[1]	**$ 1.69**	$ 1.57	$ 1.45
Undistributed earnings – continuing operations, basic	**1.56**	1.66	1.34
Undistributed earnings – discontinued operations, basic	**–**	0.41	–
Total	**$ 3.25**	$ 3.64	$ 2.79

(1) Distributed earnings, basic may differ from actual per share amounts paid as dividends, as the EPS computation under GAAP requires the use of the weighted average, rather than the actual, number of shares outstanding.

In calculating diluted EPS, PG&E Corporation applies the if-converted method to reflect the dilutive effect of the Convertible Subordinated Notes to the extent that the impact is dilutive when compared to basic EPS. In addition, PG&E Corporation applies the treasury stock method of reflecting the dilutive effect of outstanding stock-based compensation in the calculation of diluted EPS. The following is a reconciliation of PG&E Corporation's income available for common shareholders and weighted average shares of common stock outstanding for calculating diluted EPS for 12 months ended December 31, 2009:

(in millions, except per share amounts)	December 31, 2009
Diluted	
Income Available for Common Shareholders	**$1,220**
Add earnings impact of assumed conversion of participating securities:	
Interest expense on convertible subordinated notes, net of tax	**15**
Unrealized loss on embedded derivative, net of tax	**2**
Income Available for Common Shareholders and Assumed Conversion	**$1,237**
Weighted average common shares outstanding, basic	**368**
Add incremental shares from assumed conversions:	
Convertible subordinated notes	**17**
Employee share-based compensation	**1**
Weighted average common shares outstanding, diluted	**386**
Total earnings per common share, diluted	**$ 3.20**

Stock options to purchase 7,285 shares of PG&E Corporation common stock were excluded from the computation of diluted EPS for the 12 months ended December 31, 2009 because the exercise prices of these options were greater than the average market price of PG&E Corporation common stock during this period.

The following is a reconciliation of PG&E Corporation's income available for common shareholders and weighted average shares of common stock outstanding for calculating diluted EPS for the 12 months ended December 31, 2008 and 2007:

	December 31,	
(in millions, except per share amounts)	2008	2007
Diluted		
Income Available for Common Shareholders	$1,338	$1,006
Less: distributed earnings to common shareholders	560	508
Undistributed earnings	778	498
Less: undistributed earnings from discontinued operations	154	–
Undistributed earnings from continuing operations	$ 624	$ 498
Allocation of undistributed earnings to common shareholders		
Distributed earnings to common shareholders	$ 560	$ 508
Undistributed earnings allocated to common shareholders – continuing operations	593	473
Undistributed earnings allocated to common shareholders – discontinued operations	146	–
Total common shareholders earnings	$1,299	$ 981
Weighted average common shares outstanding, basic	357	351
Convertible subordinated notes	19	19
Weighted average common shares outstanding and participating securities, basic	376	370
Weighted average common shares outstanding, basic	357	351
Employee share-based compensation	1	2
Weighted average common shares outstanding, diluted	358	353
Convertible subordinated notes	19	19
Weighted average common shares outstanding and participating securities, diluted	377	372
Net earnings per common share, diluted		
Distributed earnings, diluted	$ 1.56	$ 1.44
Undistributed earnings – continuing operations, diluted	1.66	1.34
Undistributed earnings – discontinued operations, diluted	0.41	–
Total earnings per common share, diluted	$ 3.63	$ 2.78

Stock options to purchase 11,935, and 7,285 shares of PG&E Corporation common stock were excluded from the computation of diluted EPS for the 12 months ended December 31, 2008 and 2007, respectively, because the exercise prices of these options were greater than the average market price of PG&E Corporation common stock during these periods.

NOTE 9: INCOME TAXES

The significant components of income tax provision (benefit) for continuing operations were as follows:

	PG&E Corporation			Utility		
	Year Ended December 31,					
(in millions)	**2009**	2008	2007	**2009**	2008	2007
Current:						
Federal	**$ (747)**	$(268)	$526	**$ (696)**	$(188)	$563
State	**(41)**	33	140	**(45)**	24	149
Deferred:						
Federal	**1,161**	604	(81)	**1,139**	596	(92)
State	**92**	62	(40)	**89**	62	(43)
Tax credits, net	**(5)**	(6)	(6)	**(5)**	(6)	(6)
Income tax provision	**$ 460**	$ 425	$539	**$ 482**	$ 488	$571

The following describes net deferred income tax liabilities:

	PG&E Corporation		Utility	
	Year Ended December 31,			
(in millions)	**2009**	2008	**2009**	2008
Deferred income tax assets:				
Customer advances for construction	**$ 8**	$ 199	**$ 8**	$ 199
Reserve for damages	**138**	130	**138**	129
Environmental reserve	**227**	225	**227**	225
Compensation	**338**	339	**304**	306
Other	**176**	231	**172**	201
Total deferred income tax assets	**$ 887**	$1,124	**$ 849**	$1,060
Deferred income tax liabilities:				
Regulatory balancing accounts	**$1,340**	$1,425	**$1,340**	$1,425
Property related basis differences	**4,036**	2,819	**4,032**	2,813
Income tax regulatory asset	**418**	345	**418**	345
Unamortized loss on reacquired debt	**93**	102	**93**	102
Other	**64**	81	**64**	81
Total deferred income tax liabilities	**$5,951**	$4,772	**$5,947**	$4,766
Total net deferred income tax liabilities	**$5,064**	$3,648	**$5,098**	$3,706
Classification of net deferred income tax liabilities:				
Included in current liabilities	**$ 332**	$ 251	**$ 334**	$ 257
Included in noncurrent liabilities	**4,732**	3,397	**4,764**	3,449
Total net deferred income tax liabilities	**$5,064**	$3,648	**$5,098**	$3,706

The differences between income taxes and amounts calculated by applying the federal statutory rate to income before income tax expense for continuing operations were as follows:

	PG&E Corporation			Utility		
	Year Ended December 31,					
	2009	2008	2007	**2009**	2008	2007
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)	**1.6**	3.1	4.2	**1.4**	3.3	4.3
Effect of regulatory treatment of fixed asset differences	**(2.7)**	(3.2)	(3.0)	**(2.6)**	(3.1)	(2.9)
Tax credits, net	**(0.5)**	(0.5)	(0.7)	**(0.5)**	(0.5)	(0.7)
IRS audit settlements	**(4.5)**	(7.1)	–	**(4.2)**	(4.1)	–
Other, net	**(1.5)**	(0.9)	(0.6)	**(1.3)**	(1.7)	0.1
Effective tax rate	**27.4%**	26.4%	34.9%	**27.8%**	28.9%	35.8%

PG&E Corporation and the Utility recognize a tax benefit if it is more likely than not that a tax position taken or expected to be taken in a tax return will be sustained upon examination by taxing authorities based on the merits of the position. The tax benefit recognized in the financial statements is measured based on the largest amount of benefit that is greater than 50% likely of being realized upon settlement. The difference between a tax position taken or expected to be taken in a tax return and the benefit recognized and measured pursuant to this guidance represents an unrecognized tax benefit.

The following table reconciles the changes in unrecognized tax benefits:

(in millions)	PG&E Corporation	Utility
Balance at January 1, 2007	$ 212	$ 90
Additions for tax position taken during a prior year	15	4
Reductions for tax position taken during a prior year	(18)	–
Balance at December 31, 2007	$ 209	$ 94
Additions for tax position taken during the current year	43	20
Settlements	(177)	(77)
Balance at December 31, 2008	$ 75	$ 37
Additions for tax position taken during a prior year	4	4
Additions of tax position taken during the current year	624	623
Settlements	(27)	(12)
Reductions for tax position taken during a prior year	(3)	–
Balance at December 31, 2009	**$ 673**	**$652**

The component of unrecognized tax benefits that, if recognized, would affect the effective tax rate at December 31, 2009 for PG&E Corporation and the Utility is $36 million and $22 million, respectively, with the remaining balance representing the probable deferral of taxes to later years. It is reasonably possible that unrecognized tax benefits could decrease in the next 12 months by an amount ranging from $0 to $30 million.

PG&E Corporation and the Utility recognize accrued interest and penalties related to unrecognized tax benefits as income tax expense in the Consolidated Statements of Income. Interest income and penalties recognized in income tax expense by PG&E Corporation in 2009 and 2008 was $19 million and $24 million, respectively. In 2007, interest expense recognized by PG&E Corporation was $4 million. Interest income and penalties recognized in income tax expense by the Utility in 2009 and 2008 was $14 million and $11 million, respectively. In 2007, interest expense recognized by the Utility was $1 million.

As of December 31, 2009, PG&E Corporation and the Utility had accrued interest income and penalties of $11 million and $12 million, respectively. As of December 31, 2008, PG&E Corporation and the Utility had accrued interest expense and penalties of $8 million and $3 million, respectively.

In 2009, PG&E Corporation recognized an income tax benefit of $56 million from settling a claim with the Internal Revenue Service (“IRS”) related to 1998 and 1999. Additionally during 2009, PG&E Corporation recognized $12 million in California benefits, of which $10 million was attributable to this settlement and $2 million was attributable to the 2001–2004 IRS settlement. (The 2001–2004 IRS settlement resulted in a $154 million tax benefit related to National Energy & Gas Transmission, Inc. (“NEGT”) and was recorded as discontinued operations in 2008.) PG&E Corporation received total cash refunds of $605 million in 2009 related to these settlements.

The IRS is currently auditing PG&E Corporation’s consolidated 2005–2007 income tax returns. The IRS has not proposed any material adjustments. In September 2009, the IRS released standards related to the treatment of indirect service costs for the 2005–2007 audit period, enabling PG&E Corporation to recognize a net tax benefit of $17 million.

PG&E Corporation also participates in the Compliance Assurance Process (“CAP”), a real-time IRS audit intended to expedite the resolution of tax years. PG&E Corporation is under CAP for 2008 and 2009. In 2009, the IRS signed a Partial Acceptance Letter accepting the 2008 tax return except for several issues to be resolved in appeals or through a field audit. The reserved items included a tax accounting method change request related to the deduction of repairs submitted by PG&E Corporation in 2008 that was approved in 2009 and resulted in the recording of a $2 million benefit, including interest. The IRS is conducting a field audit to examine the size of the adjustment resulting from the method change. The IRS has proposed no material adjustments for either 2008 or 2009.

The primary impact to PG&E Corporation’s and the Utility’s balance sheets from the events described above is an increase in regulatory assets of $37 million, an increase in noncurrent income tax receivables of $624 million, and an increase in noncurrent deferred tax liabilities of $803 million in 2009.

Additionally, the California Franchise Tax Board is auditing PG&E Corporation's 2004 and 2005 combined California income tax returns and amended income tax returns filed by PG&E Corporation to reflect settlements made with the IRS. To date, no material adjustments have been proposed. PG&E Corporation believes final resolution of the Federal and California audits will not have a material adverse impact on its financial condition or results of operations. PG&E Corporation is neither under audit nor subject to any material risk in any other jurisdiction.

In 2009, PG&E Corporation recorded a $14 million benefit, including interest, upon reaching an agreement with the IRS allowing deductions for items that had previously been included in the capital loss carry forwards. As a result, as of December 31, 2009, PG&E Corporation has $25 million of federal and California capital loss carry forwards based on filed tax returns, of which approximately $10 million will expire if not used by 2011. For all periods presented, PG&E Corporation has provided a full valuation allowance against its deferred tax assets for capital loss carry forwards.

NOTE 10: DERIVATIVES AND HEDGING ACTIVITIES

USE OF DERIVATIVE INSTRUMENTS

The Utility faces market risk primarily related to electricity and natural gas commodity prices. Substantially all of the Utility's risk management activities involving derivatives occur to reduce the volatility of commodity costs on behalf of its customers. The CPUC and the FERC allow the Utility to charge customer rates designed to recover the Utility's reasonable costs of providing services, including the cost to obtain and deliver electricity and natural gas. As these costs are passed through to customers, the Utility's earnings are not exposed to the commodity price risk inherent in the purchase and sale of electricity and natural gas.

The Utility uses both derivative and non-derivative contracts in managing its customers' exposure to commodity-related price risk, including:

- forward contracts that commit the Utility to purchase a commodity in the future;
- swap agreements that require payments to or from counterparties based upon the difference between two prices for a predetermined contractual quantity;
- option contracts that provide the Utility with the right to buy a commodity at a predetermined price; and
- futures contracts that are exchange-traded contracts that commit the Utility to purchase a commodity or make a cash settlement at a specified price and future date.

These instruments are not held for speculative purposes and are subject to certain regulatory requirements.

COMMODITY-RELATED PRICE RISK

Commodity-related price risk management activities that meet the definition of a derivative are recorded at fair value on the Consolidated Balance Sheets. Certain commodity-related price risk management activities reduce the cash flow variability associated with fluctuating commodity prices. Prior to September 2009, the Utility designated qualifying derivative transactions as cash flow hedges for accounting purposes. As long as the ratemaking mechanisms discussed above remain in place and the Utility's risk management activities are carried out in accordance with CPUC directives, the Utility expects to fully recover from customers, in rates, all costs related to commodity-related price risk-related derivative instruments. Therefore, all unrealized gains and losses associated with the fair value of these derivative instruments, including those designated as cash flow hedges, are deferred and recorded within the Utility's regulatory assets and liabilities on the Consolidated Balance Sheets. (See Note 3 of the Notes to the Consolidated Financial Statements.) Net realized gains or losses on derivative instruments related to price risk for commodities are recorded in the cost of electricity or the cost of natural gas with corresponding increases or decreases to regulatory balancing accounts for recovery from customers. As of September 30, 2009, the Utility de-designated all cash flow hedge relationships. Due to the regulatory accounting treatment described above, the de-designation of cash flow hedge relationships had no impact on Income Available for Common Shareholders or the Consolidated Balance Sheets.

The Utility elects the normal purchase and sale exception for qualifying commodity-related derivative instruments. Derivative instruments that require physical delivery, are probable of physical delivery in quantities that are expected to be used by the Utility over a reasonable period in the normal course of business, and do not contain pricing provisions unrelated to the commodity delivered are eligible for the normal purchase and sale exception. The fair value of instruments that are eligible for the normal purchase and sales exception are not reflected in the Consolidated Balance Sheets.

The following is a discussion of the Utility's use of derivative instruments intended to mitigate commodity-related price risk for its customers.

Electricity Procurement

The Utility obtains electricity from a diverse mix of resources, including third-party power purchase agreements, amounts allocated under DWR contracts, and its own electricity generation facilities. The amount of electricity the Utility needs to meet the demands of customers and 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 or terminations of existing electricity purchase contracts, including the DWR's contracts;
- the execution of new electricity 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 or decline, 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.

The Utility enters into third-party power purchase agreements to ensure sufficient electricity to meet customer needs. The Utility's third-party power purchase agreements are generally accounted for as leases, but certain third-party power purchase agreements are considered derivative instruments and, therefore, are recorded at fair value within the Consolidated Balance Sheets. The Utility elects to use the normal purchase and sale exception for eligible derivative instruments. Derivative instruments that are eligible for the normal purchase and normal sales exception are not required to be recorded at fair value.

A portion of the Utility's third-party power purchase agreements contain market-based pricing terms. In order to reduce the cash flow variability associated with fluctuating electricity prices, the Utility has entered into financial swap contracts to effectively fix the price of future purchases under those power purchase agreements. These financial swaps are considered derivative instruments and are recorded at fair value within the Consolidated Balance Sheets.

The CPUC has approved a long-term electricity procurement plan covering 2007 through 2016. The Utility's electricity procurement and financial swaps are transacted in accordance with the approved plan. The Utility recovers the costs incurred under these contracts and other electricity procurement costs through retail electricity rates that are adjusted whenever the forecasted aggregate over-collections or under-collections of the Utility's procurement costs for the current year exceed 5% of the Utility's prior year electricity procurement revenues. The Chapter 11 Settlement Agreement provides that the Utility will recover its reasonable costs of providing utility service, including power procurement costs. 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.

Electric Transmission Congestion Revenue Rights

The CAISO-controlled electricity transmission grid used by the Utility to transmit power is subject to transmission constraints. As a result, the Utility is subject to financial risk associated with the cost of transmission congestion. The CAISO implemented its new day-ahead wholesale electricity market as part of its Market Redesign and Technology Update on April 1, 2009. The CAISO created Congestion Revenue Rights ("CRRs") to allow market participants, including load-serving entities, to hedge the financial risk of CAISO-imposed congestion charges in the new day-ahead market. The CAISO releases CRRs through an annual and monthly process, each of which includes an allocation phase (in which load-serving entities are allocated CRRs at no cost based on the customer demand or "load" they serve) and an auction phase (in which CRRs are priced at market and available to all market participants). In 2009, the Utility acquired CRRs through both allocation and auction. The costs associated with CRRs are filed with the CPUC along with electric procurement costs for recovery. The Utility is at risk to the extent that the CPUC may in the future disallow portions or the full costs of procurement transactions. CRRs are considered derivative instruments and are recorded at fair value within the Consolidated Balance Sheets.

Natural Gas Procurement (Electric Portfolio)

The Utility's electric procurement portfolio is exposed to natural gas price risk primarily through the Utility-owned natural gas generating facilities, tolling agreements, and natural gas-indexed electricity procurement contracts. In order to reduce the future cash flow variability associated with fluctuating natural gas prices, the Utility purchases financial instruments such as futures, swaps, and options.

These financial instruments are considered derivative instruments and are recorded at fair value within the Consolidated Balance Sheets.

The Utility manages natural gas price risk associated with its electric procurement portfolio in accordance with its risk management strategies included in electricity procurement plans approved by the CPUC. The CPUC did not approve the Utility's proposed electric portfolio gas hedging plan that was included in the Utility's long-term procurement plan. Instead, the CPUC deferred consideration of the proposal to another proceeding. The CPUC ordered the Utility to continue operating under the previously approved gas hedging plan. The expenses associated with the hedging plan are expected to be recovered through rates.

Natural Gas Procurement (Small Commercial and Residential Customers)

The Utility enters into physical natural gas commodity contracts to fulfill the needs of its small commercial and residential, or "core," customers. (The Utility does not procure natural gas for industrial and large commercial, or "non-core," customers.) Changes in temperature cause natural gas demand to vary daily, monthly, and seasonally. Consequently, varying volumes of gas may be purchased or sold in the monthly and, to a lesser extent, daily spot market to balance such seasonal supply and demand.

The Utility manages its winter exposure to variable natural gas prices in accordance with its CPUC-approved annual core portfolio hedging implementation plans. Accordingly, the Utility has entered into various financial instruments, such as swaps and options, intended to reduce the uncertainty associated with fluctuating natural gas purchase prices. These financial instruments are considered derivative instruments that are recorded at fair value within the Consolidated Balance Sheets.

OTHER RISK

At December 31, 2009, PG&E Corporation had $247 million of Convertible Subordinated Notes outstanding scheduled to mature on June 30, 2010. The 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 prices. The dividend participation rights associated with the Convertible Subordinated Notes are embedded derivative instruments 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 fair value of the dividend participation rights are recognized in PG&E Corporation's Consolidated Statements of Income as non-operating expense or income (in Other income (expense), net).

VOLUME OF DERIVATIVE ACTIVITY

At December 31, 2009, the volume of PG&E Corporation's and the Utility's outstanding derivative contracts was as follows:

		Contract Volume(1)			
Underlying Product	Instruments	Less Than 1 Year	Greater Than 1 Year but Less Than 3 Years	Greater Than 3 Years but Less Than 5 Years	Greater Than 5 Years(2)
Natural Gas(3) (MMBtus(4))	Forwards, Futures, and Swaps	288,485,226	167,046,788	15,512,500	–
	Options	175,269,728	99,834,308	–	–
Electricity (Megawatt-hours)	Forwards, Futures, and Swaps	3,830,256	7,787,609	4,652,112	4,233,696
	Options	9,400	11,450	136,048	532,444
	Congestion Revenue Rights	86,222,176	66,936,541	66,869,998	118,548,809
PG&E Corporation Equity (Shares)	Dividend Participation Rights	16,370,789	–	–	–

(1) Amounts shown reflect the total gross derivative volumes by commodity type that are expected to settle in each time period.
(2) Derivatives in this category expire between 2015 and 2022.
(3) Amounts shown are for the combined positions of the electric and core gas portfolios.
(4) Million British Thermal Units.

PRESENTATION OF DERIVATIVE INSTRUMENTS IN THE FINANCIAL STATEMENTS

In PG&E Corporation's and the Utility's Consolidated Balance Sheets, derivative instruments are presented on a net basis by counterparty where the right of offset exists. The net balances include outstanding cash collateral associated with derivative positions.

At December 31, 2009, PG&E Corporation's and the Utility's outstanding derivative balances were as follows:

(in millions)	Gross Derivative Balance(1)	Netting(2)	Cash Collateral(2)	Total Derivative Balances
Commodity Risk (PG&E Corporation and Utility)				
Current Assets – Prepaid expenses and other	$ 76	$(12)	$ 77	$ 141
Other Noncurrent Assets – Other	64	(44)	13	33
Current Liabilities – Other	(231)	12	54	(165)
Noncurrent Liabilities – Other	(390)	44	44	(302)
Total commodity risk	$(481)	$ –	$188	$(293)
Other Risk Instruments(3) (PG&E Corporation Only)				
Current Liabilities – Other	$ (13)	$ –	$ –	$ (13)
Total derivatives	$(494)	$ –	$188	$(306)

(1) See Note 11 of the Notes to the Consolidated Financial Statements for a discussion of the valuation techniques used to calculate the fair value of these instruments.
(2) Positions, by counterparty, are netted where the intent and legal right to offset exist in accordance with master netting agreements.
(3) This category relates to the dividend participation rights of PG&E Corporation's Convertible Subordinated Notes.

Expenses related to the dividend participation rights are not recoverable in customers' rates. Therefore, changes in the fair value of these instruments are recorded in PG&E Corporation's Consolidated Statements of Income.

For the 12-month period ended December 31, 2009, the gains and losses recorded on PG&E Corporation's and the Utility's derivative instruments were as follows:

(in millions)	Commodity Risk (PG&E Corporation and Utility)
Unrealized gain/(loss) – Regulatory assets and liabilities(1)	**$ 15**
Realized gain/(loss) – Cost of electricity(2)	**(701)**
Realized gain/(loss) – Cost of natural gas(2)	**(54)**
Total commodity risk instruments	**$(740)**

(1) Unrealized gains and losses on commodity risk-related derivative instruments are recorded to regulatory assets or liabilities rather than being recorded to the Consolidated Statements of Income. These amounts exclude the impact of cash collateral postings.
(2) These amounts are fully passed through to customers in rates. Accordingly, net income was not impacted by realized amounts on these instruments.

Cash inflows and outflows associated with the settlement of all derivative instruments are recognized in operating cash flows on PG&E Corporation's and the Utility's Consolidated Statements of Cash Flows.

The majority of the Utility's commodity risk-related derivative instruments contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies. If the Utility's credit rating were to fall below investment grade, the Utility would be required to immediately post additional cash to fully collateralize its net liability derivative positions.

At December 31, 2009, the additional cash collateral that the Utility would be required to post if its credit risk-related contingency features were triggered was as follows:

(in millions)	
Derivatives in a liability position with credit risk-related contingencies that are not fully collateralized	$(522)
Related derivatives in an asset position	50
Collateral posting in the normal course of business related to these derivatives	12
Net position of derivative contracts/additional collateral posting requirements(1)	$(460)

(1) This calculation excludes the impact of closed but unpaid positions, as their settlement is not impacted by any of the Utility's credit risk-related contingencies.

NOTE 11: FAIR VALUE MEASUREMENTS

PG&E Corporation and the Utility determine the fair value of certain assets and liabilities based on assumptions that market participants would use in pricing the assets or liabilities. PG&E Corporation and the Utility utilize a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value and give precedence to observable inputs in determining fair value. An instrument's level within the hierarchy is based on the lowest level of any significant input to the fair value measurement. The following levels were established for each input:

- **Level 1:** "Inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date." Active markets are those in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis. Instruments classified as Level 1 consist of financial instruments such as exchange-traded derivatives (other than options), listed equities, and U.S. government treasury securities.
- **Level 2:** "Inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly." Instruments classified as Level 2 consist of financial instruments such as non-exchange-traded derivatives (other than options) valued using exchange inputs and exchange-traded derivatives (other than options) for which the market is not active.
- **Level 3:** "Unobservable inputs for the asset or liability." These are inputs for which there is no market data available or observable inputs that are adjusted using Level 3 assumptions. Instruments classified as Level 3 consist primarily of financial and physical instruments such as options, non-exchange-traded derivatives valued using broker quotes, and new and/or complex instruments that have immature or limited markets.

The following table sets forth the fair value hierarchy by level of PG&E Corporation's and the Utility's recurring fair value financial instruments as of December 31, 2009 and 2008. The instruments are classified based on the lowest level of input that is significant to the fair value measurement. PG&E Corporation's and the Utility's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	PG&E Corporation			
	Fair Value Measurements at December 31, 2009			
(in millions)	Level 1	Level 2	Level 3	Total
Assets:				
Money market investments (held by PG&E Corporation)	**$ 189**	**$ –**	**$ 4**	**$ 193**
Nuclear decommissioning trusts				
Equity securities	**1,106**	**6**	**–**	**1,112**
U.S. government and agency issues	**653**	**51**	**–**	**704**
Municipal bonds and other	**1**	**197**	**–**	**198**
Total nuclear decommissioning trusts(1)	**1,760**	**254**	**–**	**2,014**
Rabbi trusts-equity securities	**81**	**–**	**–**	**81**
Long-term disability trust				
Equity securities	**52**	**23**	**–**	**75**
Corporate debt securities	**–**	**113**	**–**	**113**
Total long-term disability trust	**52**	**136**	**–**	**188**
Total assets	**$2,082**	**$390**	**$ 4**	**$2,476**
Liabilities:				
Dividend participation rights	**$ –**	**$ –**	**$ 12**	**$ 12**
Price risk management instruments(2)	**3**	**73**	**217**	**293**
Other	**–**	**–**	**3**	**3**
Total liabilities	**$ 3**	**$ 73**	**$232**	**$ 308**

(1) Excludes deferred taxes on appreciation of investment value.
(2) Balances include the impact of netting adjustments of $108 million to Level 1, $48 million to Level 2, and $32 million to Level 3.

PG&E Corporation

(in millions)	Fair Value Measurements at December 31, 2008 Level 1	Level 2	Level 3	Total
Assets:				
Money market investments (held by PG&E Corporation)	$ 164	$ –	$ 12	$ 176
Nuclear decommissioning trusts				
Equity securities	893	–	5	898
U.S. government and agency issues	603	86	–	689
Municipal bonds and other	9	203	–	212
Total nuclear decommissioning trusts(1)	1,505	289	5	1,799
Rabbi trusts	66	–	–	66
Long-term disability trust				
Equity securities	99	–	54	153
Corporate debt securities	–	–	24	24
Total long-term disability trust	99	–	78	177
Total assets	$1,834	$289	$ 95	$2,218
Liabilities:				
Dividend participation rights	$ –	$ –	$ 42	$ 42
Price risk management instruments(2)	(49)	123	156	230
Other	–	–	2	2
Total liabilities	$ (49)	$123	$200	$ 274

(1) Excludes taxes on appreciation of investment value.
(2) Balances include the impact of netting adjustments of $159 million to Level 1, $32 million to Level 2, and $76 million to Level 3.

Utility

(in millions)	**Fair Value Measurements at December 31, 2009** Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trusts				
Equity securities	**$1,106**	**$ 6**	**$ –**	**$1,112**
U.S. government and agency issues	**653**	**51**	**–**	**704**
Municipal bonds and other	**1**	**197**	**–**	**198**
Total nuclear decommissioning trusts(1)	**1,760**	**254**	**–**	**2,014**
Long-term disability trust				
Equity securities	**52**	**23**	**–**	**75**
Corporate debt securities	**–**	**113**	**–**	**113**
Total long-term disability trust	**52**	**136**	**–**	**188**
Total assets	**$1,812**	**$390**	**$ –**	**$2,202**
Liabilities:				
Price risk management instruments(2)	**$ 3**	**$ 73**	**$217**	**$ 293**
Other	**–**	**–**	**3**	**3**
Total liabilities	**$ 3**	**$ 73**	**$220**	**$ 296**

(1) Excludes deferred taxes on appreciation of investment value.
(2) Balances include the impact of netting adjustments of $108 million to Level 1, $48 million to Level 2, and $32 million to Level 3.

Utility

(in millions)	Fair Value Measurements at December 31, 2008 Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trusts(1)				
Equity securities	$ 893	$ –	$ 5	$ 898
U.S. government and agency issues	603	86	–	689
Municipal bonds and other	9	203	–	212
Total nuclear decommissioning trusts(1)	1,505	289	5	1,799
Long-term disability trust				
Equity securities	99	–	54	153
Corporate debt securities	–	–	24	24
Total long-term disability trust	99	–	78	177
Total assets	$1,604	$289	$ 83	$1,976
Liabilities:				
Price risk management instruments(2)	(49)	123	156	230
Other	–	–	2	2
Total liabilities	$ (49)	$123	$158	$ 232

(1) Excludes taxes on appreciation of investment value.
(2) Balances include the impact of netting adjustments of $159 million to Level 1, $32 million to Level 2, and $76 million to Level 3.

PG&E Corporation's and the Utility's fair value measurements incorporate various factors, such as nonperformance and credit risk adjustments. At December 31, 2009, the nonperformance and credit risk adjustment represented an immaterial amount of the net price risk management value. PG&E Corporation and the Utility utilize a mid-market pricing convention (the midpoint between bid and ask prices) as a practical expedient in valuing the majority of its derivative assets and liabilities at fair value.

MONEY MARKET INVESTMENTS

PG&E Corporation invests in AAA-rated money market funds that seek to maintain a stable net asset value. These funds invest in high-quality, short-term, diversified money market instruments, such as treasury bills, federal agency securities, certificates of deposit, and commercial paper with a maximum weighted average maturity of 60 days or less. PG&E Corporation's investments in these money market funds are generally valued based on observable inputs such as expected yield and credit quality and are thus classified as Level 1 instruments. Approximately $189 million held in money market funds are recorded as Cash and cash equivalents in PG&E Corporation's Consolidated Balance Sheets.

As of December 31, 2009, PG&E Corporation classified approximately $4 million invested in one money market fund as a Level 3 instrument because the fund manager imposed restrictions on fund participants' redemption requests. PG&E Corporation's investment in this money market fund is recorded as Prepaid expenses and other in PG&E Corporation's Consolidated Balance Sheets.

TRUST ASSETS

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

The Consolidated Balance Sheets of PG&E Corporation and the Utility contain assets held in trust for the PG&E Retirement Plan Master Trust, the Postretirement Life Insurance Trust, and the Postretirement Medical Trusts presented on a net basis. See Note 13 of the Notes to the Consolidated Financial Statements for further discussion. The pension assets are presented net of pension obligations as Noncurrent Liabilities – Other in PG&E Corporation's and the Utility's Consolidated Balance Sheets.

PRICE RISK MANAGEMENT INSTRUMENTS

Price risk management instruments are composed of physical and financial derivative contracts, including futures, forwards, options, and swaps that are both exchange-traded and over-the-counter ("OTC")-traded contracts. PG&E Corporation and the Utility consistently apply valuation methodology among their instruments. The Utility is permitted to defer the unrealized gains and losses associated with these derivatives, as they are expected to be refunded or recovered in future rates.

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

The Utility holds CRRs to hedge financial risk of CAISO-imposed congestion charges in the day-ahead markets. The Utility's demand response contracts ("DRs") with third-party aggregators of retail electricity customers contain a call option entitling the Utility to require that the aggregator reduce electric usage by the aggregator's customers at times of peak energy demand or in response to a CAISO alert or other emergency. As the market for CRRs and DRs has minimal activity, observable inputs may not be available in pricing these instruments. Therefore, the pricing models used to value these instruments often incorporate significant estimates and assumptions that market participants would use in pricing the instrument. Accordingly, they are classified as Level 3 measurements. When available, observable market data is used to calibrate pricing models.

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

See Note 10 of the Notes to the Consolidated Financial Statements for further discussion of the price risk management instruments.

DIVIDEND PARTICIPATION RIGHTS

The dividend participation rights of the Convertible Subordinated Notes are embedded derivative instruments and, therefore, are bifurcated from Convertible Subordinated Notes and recorded at fair value in PG&E Corporation's Consolidated Balance Sheets. The dividend participation rights are valued based on the net present value of estimated future cash flows using internal estimates of future common stock dividends. The fair value of the dividend participation rights is recorded as Current Liabilities – Other and Noncurrent Liabilities – Other in PG&E Corporation's Consolidated Balance Sheets. (See Note 4 of the Notes to the Consolidated Financial Statements for further discussion of these instruments.)

FINANCIAL INSTRUMENTS

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, short-term borrowings, accounts payable, customer deposits, and the Utility's variable rate pollution control bond loan agreements approximate their carrying values at December 31, 2009 and 2008.

- The fair values of the Utility's fixed rate senior notes and fixed rate pollution control bond loan agreements, PG&E Corporation's Convertible Subordinated Notes, PG&E Corporation's fixed rate senior notes, and the ERBs issued by PERF were based on quoted market prices at December 31, 2009 and 2008.

The carrying amount and fair value of PG&E Corporation's and the Utility's financial instruments were as follows (the table below excludes financial instruments with carrying values that approximate their fair values):

	At December 31,			
	2009		2008	
(in millions)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Debt (Note 4):				
PG&E Corporation	**$ 597**	**$1,096**	$ 280	$ 739
Utility	**9,240**	**9,824**	8,740	9,134
Energy recovery bonds (Note 5)	**1,213**	**1,269**	1,583	1,564

LEVEL 3 ROLLFORWARD

The following table is a reconciliation of changes in fair value of PG&E Corporation's instruments that have been classified as Level 3 in the fair value hierarchy for the years ended 2009 and 2008:

	PG&E Corporation Only		PG&E Corporation and the Utility					
(in millions)	Money Market	Dividend Participation Rights	Price Risk Management Instruments	Nuclear Decommissioning Trusts Equity Securities(1)	Long-Term Disability Equity Securities	Long-Term Disability Corp. Debt Securities	Other	Total
Asset (Liability) Balance as of January 1, 2008	$ –	$(68)	$ 115	$ 8	$ 61	$ 26	$(4)	$ 138
Realized and unrealized gains (losses):								
Included in earnings	–	(3)		–	(35)	1	–	(37)
Included in regulatory assets and liabilities or balancing accounts	–	–	(271)	(3)	–	–	2	(272)
Purchases, issuances, and settlements	(50)	29	–	–	28	(3)	–	4
Transfers in to (out of) Level 3	62	–	–	–	–	–	–	62
Asset (Liability) Balance as of December 31, 2008	$ 12	$(42)	$(156)	$ 5	$ 54	$ 24	$(2)	$(105)
Realized and unrealized gains (losses):								
Included in earnings	–	2		–	12	3	–	17
Included in regulatory assets and liabilities or balancing accounts	–	–	(61)	1	–	–	(1)	(61)
Purchases, issuances, and settlements	(8)	28	–	–	(43)	86	–	63
Transfers in to (out of) Level 3	–	–	–	(6)	(23)	(113)	–	(142)
Asset (Liability) Balance as of December 31, 2009	**$ 4**	**$(12)**	**$(217)**	**$ –**	**$ –**	**$ –**	**$(3)**	**$(228)**

(1) Excludes deferred taxes on appreciation of investment value.

Earnings for the period were impacted by a $17 million unrealized gain relating to assets or liabilities still held at December 31, 2009.

PG&E Corporation and the Utility did not have any nonrecurring financial measurements as of December 31, 2009.

NOTE 12: NUCLEAR DECOMMISSIONING

The Utility's nuclear power facilities consist of two units at Diablo Canyon and the retired facility at Humboldt Bay. 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 ("NRC") license and release of the property for unrestricted use. The Utility makes contributions to trust funds (described below) to provide for the eventual decommissioning of each nuclear unit. The CPUC conducts a NDCTP every three years to review the Utility's updated nuclear decommissioning cost study and to determine the level of Utility trust contributions and related revenue requirements.

In April 2009, the Utility filed its 2009 NDCTP with new decommissioning cost estimates and other funding assumptions, such as projected cost escalation factors and projected earnings of the funds for 2010, 2011, and 2012. Hearings were completed in October 2009 and a CPUC decision is expected in the second quarter of 2010. The Utility filed a partial settlement in the 2009 NDCTP with The Utility Reform Network, Southern California Edison, and San Diego Gas & Electric on December 18, 2009.

In the Utility's 2009 NDCTP, the CPUC assumed that the eventual decommissioning of Diablo Canyon Unit 1 would be scheduled to begin in 2024 and be completed in 2052; that decommissioning of Diablo Canyon Unit 2 would be scheduled to begin in 2025 and be completed in 2052; and that decommissioning of Humboldt Bay Unit 3 would be scheduled to begin in 2010 and be completed in 2020. As presented in the Utility's 2009 NDCTP, the estimated nuclear decommissioning cost for Diablo Canyon Units 1 and 2 and Humboldt Bay Unit 3 is approximately $2.26 billion in 2009 dollars (or approximately $4.56 billion in future dollars). These estimates are based on the 2009 decommissioning cost studies, prepared in accordance with CPUC requirements. The Utility's revenue requirements for nuclear decommissioning costs (i.e., the revenue requirements used by the Utility to make contributions to the decommissioning trust funds) are recovered from customers through a non-bypassable charge that the Utility expects 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. However, for GAAP purposes, the Utility adjusts its nuclear decommissioning obligation to reflect the fair value of decommissioning its nuclear power facilities and records this as an ARO on its Consolidated Balance Sheets. The total nuclear decommissioning obligation accrued in accordance with GAAP was $1.4 billion at December 31, 2009 and December 31, 2008. Differences between amounts collected in rates for decommissioning the Utility's nuclear power facilities and the decommissioning obligation recorded in accordance with GAAP are reflected as a regulatory liability. (See Note 3 of the Notes to the Consolidated Financial Statements.)

NUCLEAR DECOMMISSIONING TRUSTS

Decommissioning costs recovered in rates are placed in nuclear decommissioning trusts. The Utility has three decommissioning trusts for its two Diablo Canyon and Humboldt Bay 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, in order 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 the facility at Humboldt Bay. 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 and non-qualified trusts to invest a maximum of 60% of its funds in publicly traded equity securities, of which up to 20% may be invested in publicly traded non-U.S. 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.

Trust earnings are included in the nuclear decommissioning trust assets and the corresponding regulatory liability for asset retirement costs. 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 the decommissioning activities.

During 2009, the trusts earned $63 million in interest and dividends. 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. All of the Utility's investment securities in the trust are classified as "available-for-sale." At December 31, 2009, the Utility had accumulated nuclear decommissioning trust funds with an estimated fair value of $1.9 billion, 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. (See Note 11 of the Notes to the Consolidated Financial Statements.)

At December 31, 2009, total unrealized losses on the investments held in the trusts were $8.0 million. The Utility concluded that the unrealized losses were other-than-temporary impairments and recorded an $8.0 million reduction to the nuclear decommissioning trusts assets and the corresponding regulatory liability asset retirement costs.

The following table provides a summary of the fair value of the available-for-sale investments held in the Utility's nuclear decommissioning trusts:

(in millions)	Amortized Cost	Total Unrealized Gains	Total Unrealized Losses	Estimated[1] Fair Value
As of December 31, 2009				
Equity securities	**$ 526**	**$588**	**$ (2)**	**$1,112**
U.S. government and agency issues	**656**	**52**	**(4)**	**704**
Municipal bonds and other	**197**	**3**	**(2)**	**198**
Total	**$1,379**	**$643**	**$ (8)**	**$2,014**
As of December 31, 2008				
Equity securities	$ 588	$340	$(27)	$ 901
U.S. government and agency issues	617	103	–	720
Municipal bonds and other	187	3	(12)	178
Total	$1,392	$446	$(39)	$1,799

(1) Excludes taxes on appreciation of investment value.

The U.S government agency obligations and state municipal bonds mature on the following schedule:

As of December 31, 2009	(in millions)
Less than 1 year	$ 57
1–5 years	368
5–10 years	238
More than 10 years	238
Total maturities of debt securities	$901

The following table provides a summary of the activity for the debt and equity securities:

	Year Ended December 31,		
(in millions)	**2009**	2008	2007
Proceeds received from sales of securities	**$1,351**	$1,635	$830
Gross realized gains on sales of securities held as available-for-sale	**27**	30	61
Gross realized losses on sales of securities held as available-for-sale	**(55)**	(142)	(42)

NOTE 13: EMPLOYEE COMPENSATION PLANS

PENSION AND OTHER POSTRETIREMENT BENEFITS

PG&E Corporation and the Utility provide a non-contributory defined benefit pension plan for eligible employees and retirees, referred to collectively as "pension benefits." PG&E Corporation and the Utility also provide contributory postretirement medical plans for eligible employees and retirees and their eligible dependents, and non-contributory postretirement life insurance plans for eligible employees and retirees (referred to collectively as "other benefits"). PG&E Corporation and the Utility have elected that certain of the trusts underlying these plans be treated under the 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 Code limitations. The following schedules aggregate all of PG&E Corporation's and the Utility's plans and are presented based on the sponsor of each plan. PG&E Corporation and the Utility use a December 31 measurement date for all plans.

Regulatory adjustments are recorded in the Consolidated Statements of Income and Consolidated Balance Sheets to reflect the difference between pension expense or income for accounting purposes and pension expense or income for ratemaking, which is based on a funding approach. A regulatory adjustment is also recorded for the amounts that would otherwise be charged to accumulated other comprehensive income for the pension benefits related to the Utility's qualified benefit pension plan.

The Utility would record a regulatory liability for a portion of the credit balance in accumulated other comprehensive income, should the other benefits be in an overfunded position. However, this recovery mechanism does not allow the Utility to record a regulatory asset for an underfunded position related to other benefits. Therefore, the charge remains in accumulated other comprehensive income (loss) for 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 2009 and 2008:

Pension Benefits

	PG&E Corporation		Utility	
(in millions)	**2009**	2008	**2009**	2008
Projected benefit obligation at January 1	**$ 9,767**	$9,081	**$ 9,717**	$9,036
Service cost for benefits earned	**227**	236	**223**	234
Interest cost	**624**	581	**621**	578
Actuarial (gain) loss	**494**	258	**490**	255
Plan amendments	**71**	2	**71**	3
Transitional costs	**3**	–	**3**	–
Benefits and expenses paid	**(420)**	(391)	**(417)**	(389)
Projected benefit obligation at December 31	**$10,766**	$9,767	**$10,708**	$9,717
Accumulated benefit obligation	**$ 9,527**	$8,601	**$ 9,479**	$8,559

Other Benefits

	PG&E Corporation		Utility	
(in millions)	**2009**	2008	**2009**	2008
Benefit obligation at January 1	**$1,382**	$1,311	**$1,382**	$1,311
Service cost for benefits earned	**30**	29	**30**	29
Interest cost	**87**	81	**87**	81
Actuarial (gain) loss	**72**	22	**72**	22
Plan amendments	**–**	–	**–**	–
Transitional costs	**1**		**1**	
Gross benefits paid	**(106)**	(101)	**(106)**	(101)
Federal subsidy on benefits paid	**4**	4	**4**	4
Plan participant contributions	**41**	36	**41**	36
Benefit obligation at December 31	**$1,511**	$1,382	**$1,511**	$1,382

CHANGE IN PLAN ASSETS

The following tables reconcile aggregate changes in plan assets during 2009 and 2008:

Pension Benefits

	PG&E Corporation		Utility	
(in millions)	**2009**	2008	**2009**	2008
Fair value of plan assets at January 1	**$8,066**	$ 9,540	**$8,066**	$ 9,540
Actual return on plan assets	**1,523**	(1,232)	**1,523**	(1,232)
Company contributions	**187**	182	**184**	179
Benefits and expenses paid	**(446)**	(424)	**(443)**	(421)
Fair value of plan assets at December 31	**$9,330**	$ 8,066	**$9,330**	$ 8,066

Other Benefits

	PG&E Corporation		Utility	
(in millions)	**2009**	2008	**2009**	2008
Fair value of plan assets at January 1	**$ 990**	$1,331	**$ 990**	$1,331
Actual return on plan assets	**166**	(316)	**166**	(316)
Company contributions	**87**	48	**87**	48
Plan participant contribution	**42**	36	**42**	36
Benefits and expenses paid	**(116)**	(109)	**(116)**	(109)
Fair value of plan assets at December 31	**$1,169**	$ 990	**$1,169**	$ 990

FUNDED STATUS

The following schedule shows the plans' aggregate funded status 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,	
(in millions)	**2009**	2008	**2009**	2008
Fair value of plan assets at December 31	**$ 9,330**	$ 8,066	**$ 9,330**	$ 8,066
Projected benefit obligation at December 31	**(10,766)**	(9,767)	**(10,708)**	(9,717)
Prepaid/(accrued) benefit cost	**$ (1,436)**	$(1,701)	**$ (1,378)**	$(1,651)
Noncurrent asset	**$ –**	$ –	**$ –**	$ –
Current liability	**(5)**	(5)	**(3)**	(3)
Noncurrent liability	**(1,431)**	(1,696)	**(1,375)**	(1,648)
Prepaid/(accrued) benefit cost	**$ (1,436)**	$(1,701)	**$ (1,378)**	$(1,651)

Other Benefits

	PG&E Corporation		Utility	
	December 31,		December 31,	
(in millions)	**2009**	2008	**2009**	2008
Fair value of plan assets at December 31	**$ 1,169**	$ 990	**$ 1,169**	$ 990
Benefit obligation at December 31	**(1,511)**	(1,382)	**(1,511)**	(1,382)
Prepaid/(accrued) benefit cost	**$ (342)**	$ (392)	**$ (342)**	$ (392)
Noncurrent asset	**$ –**	$ –	**$ –**	$ –
Noncurrent liability	**(342)**	(392)	**(342)**	(392)
Prepaid/(accrued) benefit cost	**$ (342)**	$ (392)	**$ (342)**	$ (392)

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, 2009 and 2008 were as follows:

	Pension Benefits		Other Benefits	
(in millions)	**2009**	2008	**2009**	2008
PG&E Corporation:				
Projected benefit obligation	**$(10,766)**	$(9,767)	**$(1,511)**	$(1,382)
Accumulated benefit obligation	**(9,527)**	(8,601)	**–**	–
Fair value of plan assets	**9,330**	8,066	**1,169**	990
Utility:				
Projected benefit obligation	**$(10,708)**	$(9,717)	**$(1,511)**	$(1,382)
Accumulated benefit obligation	**(9,479)**	(8,559)	**–**	–
Fair value of plan assets	**9,330**	8,066	**1,169**	990

COMPONENTS OF NET PERIODIC BENEFIT COST

Net periodic benefit cost as reflected in PG&E Corporation's Consolidated Statements of Income for 2009, 2008, and 2007 is as follows:

Pension Benefits

	December 31,		
(in millions)	**2009**	2008	2007
Service cost for benefits earned	**$ 259**	$ 236	$ 233
Interest cost	**624**	581	544
Expected return on plan assets	**(579)**	(696)	(711)
Amortization of prior service cost	**53**	47	49
Amortization of unrecognized gain	**101**	1	2
Net periodic benefit cost	**$ 458**	$ 169	$ 117

Other Benefits

	December 31,		
(in millions)	**2009**	2008	2007
Service cost for benefits earned	**$ 30**	$ 29	$ 29
Interest cost	**87**	81	79
Expected return on plan assets	**(68)**	(93)	(96)
Amortization of transition obligation	**26**	26	26
Amortization of prior service cost	**16**	16	16
Amortization of unrecognized gain	**3**	(15)	(10)
Net periodic benefit cost	**$ 94**	$ 44	$ 44

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

COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

PG&E Corporation and the Utility record the net periodic benefit cost for pension benefits and other benefits as a component of accumulated other comprehensive income (loss), net of tax. Net periodic benefit cost is composed of unrecognized prior service costs, unrecognized gains and losses, and unrecognized net transition obligations as components of accumulated other comprehensive income, net of tax.

Pre-tax amounts recognized in accumulated other comprehensive income consist of:

	PG&E Corporation	
(in millions)	**2009**	2008
Pension Benefits:		
Beginning unrecognized prior service cost	**$ (175)**	$ (222)
Current year unrecognized prior service cost	**(71)**	(2)
Amortization of unrecognized prior service cost	**53**	49
Unrecognized prior service cost	**(193)**	(175)
Beginning unrecognized net gain (loss)	**(2,113)**	105
Current year unrecognized net gain (loss)	**458**	(2,219)
Amortization of unrecognized net gain	**101**	1
Unrecognized net gain (loss)	**(1,554)**	(2,113)
Less: transfer to regulatory account[(1)]	**1,725**	2,259
Total	**$ (22)**	$ (29)
Other Benefits:		
Beginning unrecognized prior service cost	**$ (99)**	$ (116)
Current year unrecognized prior service cost	**–**	–
Amortization of unrecognized prior service cost	**16**	17
Unrecognized prior service cost	**(83)**	(99)
Beginning unrecognized net gain (loss)	**(142)**	311
Current year unrecognized net gain (loss)	**17**	(438)
Amortization of unrecognized net gain (loss)	**3**	(15)
Unrecognized net gain (loss)	**(122)**	(142)
Beginning unrecognized net transition obligation	**(102)**	(128)
Amortization of unrecognized net transition obligation	**26**	26
Unrecognized net transition obligation	**(76)**	(102)
Total	**$ (281)**	$ (343)

(1) The Utility recorded $1,725 million and $2,259 million at December 31, 2009 and 2008, respectively, as a regulatory asset balance since the Utility meets the requirement for recovery from customers in future rates.

There were no material differences between other comprehensive income for PG&E Corporation and the Utility.

The estimated amounts that will be amortized into net periodic benefit cost in 2010 are as follows:

(in millions)	PG&E Corporation	Utility
Pension benefits:		
Unrecognized prior service cost	$53	$54
Unrecognized net loss	42	41
Total	$95	$95
Other benefits:		
Unrecognized prior service cost	$16	$16
Unrecognized net loss	3	3
Unrecognized net transition obligation	26	26
Total	$45	$45

MEDICARE PRESCRIPTION DRUG, IMPROVEMENT AND MODERNIZATION ACT OF 2003

The Medicare Prescription Drug, Improvement, and Modernization Act of 2003 establishes a prescription drug benefit under Medicare ("Medicare Part D") and a tax-exempt federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that actuarially is at least equivalent to Medicare Part D. PG&E Corporation and the Utility determined that benefits provided to certain participants actuarially will be at least equivalent to Medicare Part D. Therefore, PG&E Corporation and the Utility are entitled to a tax-exempt subsidy that reduced the accumulated postretirement benefit obligation under the defined benefit medical plan at December 31, 2009 and reduced the net periodic cost for 2009 by the following amounts:

(in millions)	PG&E Corporation
Accumulated postretirement benefit obligation reduction	$71
Net periodic benefit cost reduction	7

There was no material difference between PG&E Corporation's and the Utility's Medicare Part D subsidy.

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,		
	2009	2008	2007	**2009**	2008	2007
Discount rate	**5.97%**	6.31%	6.31%	**5.66–6.09%**	5.85–6.33%	5.52–6.42%
Average rate of future compensation increases	**5.00%**	5.00%	5.00%	–	–	–
Expected return on plan assets	**6.80%**	7.30%	7.40%	**5.80–6.90%**	7.00–7.30%	7.00–7.50%

The assumed health care cost trend rate for 2009 is 7.5%, decreasing gradually to an ultimate trend rate in 2014 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	$79	$(67)
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 pension plan, the assumed return of 6.8% compares to a ten-year actual return of 4.7%. 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 approximately 500 Aa-grade non-callable bonds at December 31, 2009. 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 unrecognized gain (loss), and is considered in the determination of future net periodic benefit income (cost). The actual return on plan assets was above the expected return in 2008 and 2007. The actual return on plan assets for 2009 was lower than the expected return due to the significant decline in equity market values that occurred in 2009.

INVESTMENT POLICIES AND STRATEGIES

The financial position of PG&E Corporation's and the Utility's funded employee benefit plans is driven by the relationship between plan assets and liabilities. As noted above, the funded status is the difference between the fair value of plan assets and projected benefit obligations. Volatility in funded status occurs when asset values change differently from liability values and can result in fluctuations in costs for financial reporting as well as the amount of minimum contributions required under the

Employee Retirement Income Security Act of 1974. PG&E Corporation's and the Utility's investment policies and strategies are designed to increase the ratio of trust assets to plan liabilities at an acceptable level of funded status volatility.

Interest rate risk and equity risk are the key determinants of PG&E Corporation's and the Utility's funded status volatility. In addition to affecting the trust's fixed income portfolio market values, interest rate changes also influence liability valuations as discount rates move with current bond yields. To manage this risk, PG&E Corporation's and the Utility's trusts hold significant allocations to fixed income investments that include U.S. government securities, corporate securities, and other fixed income securities. Although they contribute to funded status volatility, equity investments are held to reduce long-term funding costs due to their higher expected return. The equity investment allocation is implemented through diversified U.S., non-U.S., and global portfolios that include common stock and commingled funds across multiple industry sectors. Absolute return investments include hedge fund portfolios that are managed to diversify the plan's holdings in equity and fixed income investments by exhibiting returns with low correlation to the direction of these markets. Over the last three years, target allocations to equity investments have generally declined in favor of longer-maturity fixed income investments as a means of dampening future funded status volatility.

PG&E Corporation and the Utility apply a risk management framework for managing the risks associated with employee benefit plan trust assets. The guiding principles of this risk management framework are the clear articulation of roles and responsibilities, appropriate delegation of authority, and proper accountability and documentation. Trust investment policies and investment manager guidelines include provisions to ensure prudent diversification, manage risk through appropriate use of physical direct asset holdings and derivative securities, and identify permitted and prohibited investments.

The target asset allocation percentages for major categories of trust assets for pension and other benefit plans at December 31, 2010, 2009, and 2008 are as follows:

	Pension Benefits			Other Benefits		
	2010	**2009**	2008	2010	**2009**	2008
U.S. Equity	26%	**32%**	31%	26%	**37%**	35%
Non-U.S. Equity	14%	**18%**	17%	13%	**18%**	16%
Global Equity	5%	**5%**	3%	3%	**3%**	2%
Absolute Return	5%	**5%**	4%	3%	**3%**	3%
Fixed Income	50%	**40%**	42%	54%	**34%**	34%
Cash Equivalents	0%	**0%**	3%	1%	**5%**	10%
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, 2009 ranged from less than one year to 88 years and the average duration of the bond portfolio was approximately 10.6 years. The maturity of fixed income securities at December 31, 2008 ranged from zero to 59 years and the average duration of the bond portfolio was approximately 12.2 years.

FAIR VALUE MEASUREMENTS

The following table presents the fair value of plan assets for pension and other benefit plans by major asset category for the year ended December 31, 2009. (For a discussion of the levels and their inputs see Note 11 of the Notes to the Consolidated Financial Statements.)

	Fair Value Measurements as of December 31, 2009			
(in millions)	Level 1	Level 2	Level 3	Total
Pension Benefits:				
U.S. Equity	**$ 411**	**$2,065**	**$ –**	**$ 2,476**
Non-U.S. Equity	**316**	**1,018**	**–**	**1,334**
Global Equity	**162**	**317**	**–**	**479**
Absolute Return	**–**	**–**	**340**	**340**
Fixed Income:				
U.S. Government	**585**	**262**	**–**	**847**
Corporate	**25**	**2,455**	**531**	**3,011**
Other	**(8)**	**233**	**190**	**415**
Cash Equivalents	**378**	**31**	**–**	**409**
Total	**$1,869**	**$6,381**	**$1,061**	**$ 9,311**
Other Benefits:				
U.S. Equity	**$ 88**	**$ 218**	**$ –**	**$ 306**
Non-U.S. Equity	**81**	**68**	**–**	**149**
Global Equity	**–**	**8**	**–**	**8**
Absolute Return	**–**	**–**	**32**	**32**
Fixed Income:				
U.S. Government	**40**	**15**	**–**	**55**
Corporate	**82**	**275**	**124**	**481**
Other	**(1)**	**13**	**17**	**29**
Cash Equivalents	**111**	**–**	**–**	**111**
Total	**$ 401**	**$ 597**	**$ 173**	**$ 1,171**
Other Assets				**17**
Total Plan Assets at Fair Value				**$10,499**

The U.S., Non-U.S., and combined Global Equity categories include equity investments in common stock and commingled funds comprised of equity across multiple industries and regions of the world. Equity investments in common stock are actively traded on a public exchange and are therefore considered Level 1 assets. These equity investments are generally valued based on unadjusted prices in active markets for identical securities. Commingled funds are maintained by investment companies for large institutional investors and are not publicly traded. Commingled funds are comprised primarily of underlying equity securities that are publicly traded on exchanges, and price quotes for the assets held by these funds are readily observable and available. Therefore, these commingled funds are categorized as Level 2 assets.

The Absolute Return category includes portfolios of hedge funds that are valued based on a variety of proprietary and non-proprietary valuation methods, including unadjusted prices for publicly-traded securities in active markets. Hedge funds are considered Level 3 assets.

The Fixed Income category includes U.S. government securities, corporate securities, and other fixed income securities. U.S. government fixed income primarily consists of U.S. Treasury notes and U.S. governments bonds that are valued based on unadjusted prices in active markets for identical transactions and are considered Level 1 assets. Corporate fixed income primarily includes investment grade bonds of U.S. issuers across multiple industries that are valued based on a compilation of primarily observable information or broker quotes in non-active markets. These securities are classified as Level 2 assets. Corporate fixed income also includes one commingled fund comprised of private corporate debt instruments. The fund is valued using pricing models and valuation inputs that are unobservable and is considered a Level 3 asset. Other fixed income primarily includes pass-through and asset-backed securities. Pass-through securities are valued based on benchmark yields created using observable market inputs and are Level 2 assets. Asset-backed securities are valued based on primarily broker quotes in non-active markets and are considered Level 3 assets. Other fixed income also includes municipal bonds and futures. Municipal bonds are valued based on a compilation of primarily observable information or broker quotes in non-active markets and are considered Level 2 assets. Futures are valued based on unadjusted prices in active markets and are Level 1 assets.

Cash equivalents consist primarily of money markets and commingled funds of short term securities that are considered Level 1 assets and valued at the net asset value of $1 per unit. The number of units held by the plan fluctuates based on the unadjusted price changes in active markets for the funds' underlying assets.

The following table is a reconciliation of changes in the fair value of instruments for pension and other benefit plans that have been classified as Level 3 in the fair value hierarchy:

(in millions)	Absolute Return	Corporate Fixed Income	Other Fixed Income	Total
Pension Benefits:				
Balance as of December 31, 2008	$263	$457	$ 291	$1,011
Actual return on plan assets:				
Relating to assets still held at the reporting date	15	82	14	111
Relating to assets sold during the period	4	4	12	20
Purchases, sales, and settlements	58	(11)	(127)	(80)
Transfers into (out of) Level 3	–	(1)	–	(1)
Balance as of December 31, 2009	**$340**	**$531**	**$ 190**	**$1,061**
Other Benefits:				
Balance as of December 31, 2008	$ 25	$116	$ 25	$ 166
Actual return on plan assets:				
Relating to assets still held at the reporting date	2	15	1	18
Relating to assets sold during the period	–	1	1	2
Purchases, sales, and settlements	5	(8)	(10)	(13)
Transfers into (out of) Level 3	–	–	–	–
Balance as of December 31, 2009	**$ 32**	**$124**	**$ 17**	**$ 173**

CASH FLOW INFORMATION

Employer Contributions

PG&E Corporation and the Utility contributed $187 million to the pension benefit plans and $87 million to the other benefit plans in 2009. These contributions are consistent with PG&E Corporation's and the Utility's funding policy, which is to contribute amounts that are tax-deductible and consistent with applicable regulatory decisions and federal minimum funding requirements. None of these pension or other benefits were subject to a minimum funding requirement requiring a cash contribution in 2009. 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 and $245 million to the pension plan during 2010 and 2011 respectively. Contributions to the other postretirement benefit plans for 2010 will be $58 million, although the contribution for 2011 will not be finalized until late 2010.

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		
2010	$ 485	$ 483
2011	517	514
2012	552	549
2013	587	584
2014	623	620
2015–2019	3,658	3,637
Other benefits		
2010	$ 109	$ 109
2011	112	112
2012	113	113
2013	117	117
2014	120	120
2015–2019	642	642

DEFINED CONTRIBUTION BENEFIT PLANS

PG&E Corporation and its subsidiaries also sponsor defined contribution benefit plans. These plans are qualified under applicable sections of the Code and provide for tax-deferred salary deductions, after-tax employee contributions, and employer contributions. Employer contribution expense reflected in PG&E Corporation's Consolidated Statements of Income was as follows:

(in millions)	PG&E Corporation	Utility
Year ended December 31,		
2009	**$52**	**$51**
2008	53	52
2007	47	46

LONG-TERM INCENTIVE PLAN

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, 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 9,703,937 shares were available for award at December 31, 2009.

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 2.5% for stock options and restricted stock and 3% for performance shares, 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 and the Utility for share-based incentive awards for the years ended December 31, 2009 and 2008:

	Year ended December 31, 2009	
(in millions)	**PG&E Corporation**	**Utility**
Stock Options	**$ –**	**$ –**
Restricted Stock	**9**	**8**
Restricted Stock Units	**11**	**7**
Performance Shares	**37**	**26**
Total Compensation Expense (pre-tax)	**$57**	**$41**
Total Compensation Expense (after-tax)	**$34**	**$24**

	Year ended December 31, 2008	
(in millions)	PG&E Corporation	Utility
Stock Options	$ 2	$ 2
Restricted Stock	22	15
Performance Shares	33	20
Total Compensation Expense (pre-tax)	$57	$37
Total Compensation Expense (after-tax)	$34	$22

Stock Options

Other than the grant of options to purchase 14,543 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 2009. 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 10-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 $5.95, $4.46, and $7.81 per share in 2009, 2008, and 2007, respectively. The significant assumptions used for shares granted in 2009, 2008, and 2007 were:

	2009	2008	2007
Expected stock price volatility	**28.8%**	18.9%	16.5%
Expected annual dividend payment	**$1.68**	$1.56	$1.44
Risk-free interest rate	**2.30%**	2.77%	4.73%
Expected life	**5.3 years**	5.4 years	5.4 years

Expected volatilities are based on historical volatility of PG&E Corporation's common stock. The expected dividend payment is the dividend yield at the date of grant. 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 expected life of stock options is derived from historical data that estimates stock option exercises and employee departure behavior.

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 and the Utility in 2009, 2008, and 2007:

(in millions)	PG&E Corporation	Utility
2009:		
Intrinsic value of options exercised	**$18**	**$13**
2008:		
Intrinsic value of options exercised	$13	$ 9
2007:		
Intrinsic value of options exercised	$59	$34

The tax benefit from stock options exercised totaled $6 million, $4 million, and $20 million for the years ended December 31, 2009, 2008, and 2007 respectively, of which $5 million, $3 million, and $10 million was recorded by the Utility.

The following table summarizes stock option activity for PG&E Corporation and the Utility for 2009:

Options	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1	2,968,261	$23.45		
Granted(1)	14,543	$35.53		
Exercised	(1,005,063)	$22.53		
Forfeited or expired	(2,400)	$29.76		
Outstanding at December 31	**1,975,341**	**$23.99**	**3.38**	**$40,812,560**
Expected to vest at December 31	**27,583**	**$38.24**	**8.18**	**$ 204,479**
Exercisable at December 31	**1,947,758**	**$23.79**	**3.31**	**$40,635,663**

(1) No stock options were awarded to employees in 2009; however, certain non-employee directors of PG&E Corporation were awarded stock options.

The following table summarizes stock option activity for the Utility for 2009:

Options	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1(1)	2,494,868	$22.99		
Granted	–	–		
Exercised	(711,652)	$22.13		
Forfeited or expired	(2,400)	$29.76		
Outstanding at December 31(1)	**1,780,816**	**$23.62**	**3.29**	**$37,446,306**
Expected to vest at December 31	**–**	**$ –**	**–**	**$ –**
Exercisable at December 31	**1,780,816**	**$23.62**	**3.29**	**$37,446,306**

(1) Includes net employee transfers of 185,045 shares between PG&E Corporation and the Utility during 2009.

As of December 31, 2009, there was less than $1 million of total unrecognized compensation cost related to outstanding stock options. That cost is expected to be recognized over a weighted average period of a year and a half for PG&E Corporation.

Restricted Stock

During 2009, PG&E Corporation awarded 11,394 shares of PG&E Corporation restricted common stock to eligible participants of PG&E Corporation and its subsidiaries, of which none were awarded to the Utility's eligible participants.

Although the recipients of restricted stock possess voting rights, they may not sell or transfer their shares until the shares vest. For restricted stock awarded in 2005, there were no performance criteria and the restrictions lapsed ratably over four years. The terms of the restricted stock awarded in 2006, 2007, and 2008, provide that 60% of the shares will vest over a period of three years at the rate of 20% per year. If PG&E Corporation's annual total shareholder return ("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 in the third year. 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 in the fifth year. Compensation expense related to the portion of the restricted stock award that is subject to conditions based on TSR is recognized over the shorter of the requisite service period and three years. Dividends declared on restricted stock are paid to recipients only when the restricted stock vests.

The tax benefit from restricted stock that vested during 2009, 2008, and 2007 totaled $1 million, $2 million, and $7 million respectively, of which $0.5 million, $1 million, and $5 million was recorded by the Utility.

The following table summarizes restricted stock activity for PG&E Corporation and the Utility for 2009:

	Number of Shares of Restricted Stock	Weighted Average Grant-Date Fair Value
Nonvested at January 1	1,287,569	$40.18
Granted	11,394	$33.02
Vested	(616,647)	$37.91
Forfeited	(11,764)	$37.47
Nonvested at December 31	**670,552**	**$37.91**

The following table summarizes restricted stock activity for the Utility for 2009:

	Number of Shares of Restricted Stock	Weighted Average Grant-Date Fair Value
Nonvested at January 1[1]	944,798	$40.20
Granted	–	–
Vested	(460,137)	$37.91
Forfeited	(10,640)	$37.47
Nonvested at December 31	**474,021**	**$47.27**

(1) Includes net employee transfers of 87,868 shares between PG&E Corporation and the Utility during 2009.

As of December 31, 2009, there was $16 million of total unrecognized compensation cost relating to restricted stock, of which $14 million related to the Utility. The cost is expected to be recognized over a weighted average period of 0.78 years by PG&E Corporation and 0.77 years by the Utility.

Restricted Stock Units

Beginning January 1, 2009, PG&E Corporation awarded restricted stock units ("RSU") instead of restricted stock as permitted by the PG&E Corporation 2006 LTIP. RSUs are hypothetical shares of stock that will generally vest in 20% increments on the first business day of March in 2010, 2011, and 2012, with the remaining 40% vesting on the first business day of March 2013. Each vested RSU is settled for one share of PG&E Corporation common stock. Additionally, upon settlement, RSU recipients receive payment for the amount of dividend equivalents associated with the vested RSUs that have accrued since the date of grant.

Performance Shares

During 2009, PG&E Corporation awarded 3,096,277 performance shares to eligible participants of PG&E Corporation and its subsidiaries, of which 2,335,637 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 performance period and are settled in cash. Upon vesting, the amount of cash that recipients are entitled to receive, if any, is determined by multiplying the number of vested performance shares by the average closing price of PG&E Corporation common stock for the last 30 calendar days of the last year in the three-year performance period. This result is then adjusted by 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 performance period. During 2009, PG&E Corporation paid $20.5 million to performance share recipients, of which $14.6 million related to Utility employees.

As of December 31, 2009, $63 million was accrued as the performance share liability for PG&E Corporation, of which $42 million related to Utility employees. The number of performance shares that were outstanding at December 31, 2009 was 1,547,113, of which 1,139,970 was related to Utility employees. Outstanding performance shares are classified as a liability on the Consolidated Balance Sheets of PG&E Corporation and the Utility because the performance shares can only be settled in cash. 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 TSR relative to its comparator group.

NOTE 14: RESOLUTION OF REMAINING CHAPTER 11 DISPUTED CLAIMS

As part of the Utility's plan of reorganization under Chapter 11, which became effective on April 12, 2004, the Utility established an escrow account for the resolution of certain disputed claims. These claims were filed by various electricity suppliers seeking payment for energy supplied to the Utility's customers through the wholesale electricity markets operated by the CAISO and the California Power Exchange ("PX") between May 2000 and June 2001. These claims are being addressed in various FERC and judicial proceedings in which the State of California, the Utility, and other electricity purchasers are seeking refunds from electricity suppliers, including municipal and governmental entities, for overcharges incurred in the CAISO and the PX wholesale electricity markets between May 2000 and June 2001. At December 31, 2009 and December 31, 2008, the Utility held $515 million and $1,212 million, respectively, in escrow, including interest earned, for payment of the remaining net disputed claims. These amounts are included within Restricted cash on the Consolidated Balance Sheets.

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

On August 26, 2009, the Utility paid $700 million to the PX from the Utility's escrow account to reduce the Utility's liability for the remaining net disputed claims. The following table presents the changes in the remaining disputed claims liability and interest accrued from December 31, 2008:

(in millions)	
Balance at December 31, 2008	$1,750
Interest accrued	53
Less: Supplier Settlements	(157)
Less: August 26, 2009 Payment	(700)
Balance at December 31, 2009	**$ 946**

At December 31, 2009, the Utility's net disputed claims liability was $946 million, consisting of $773 million of remaining disputed claims (classified on the Consolidated Balance Sheets within Accounts payable – Disputed claims and customer refunds) and interest accrued at the FERC-ordered rate of $667 million (classified on the Consolidated Balance Sheets within Interest payable) offset by accounts receivable from the CAISO and the PX of $494 million (classified on the Consolidated Balance Sheets within Accounts receivable – Customers).

Interest accrues on the liability for disputed claims at the FERC-ordered rate, which is higher than the rate earned by the Utility on the escrow balance. Although the Utility has been collecting the difference between the accrued interest and the earned interest from customers, this amount is not held in escrow. If the amount of interest accrued at the FERC-ordered rate is greater than the amount of interest ultimately determined to be owed with respect to disputed claims, the Utility would refund to customers any excess net interest collected from customers. The amount of any interest that the Utility may be required to pay will depend on the final amounts to be paid by the Utility with respect to the disputed claims.

PG&E Corporation and the Utility are unable to predict when the FERC or judicial proceedings that are still pending will be resolved, and the amount of any potential refunds that the Utility may receive or the amount of disputed claims, including interest, that the Utility will be required to pay.

NOTE 15: RELATED PARTY AGREEMENTS AND TRANSACTIONS

The Utility and other subsidiaries provide and receive various services to and from their parent, PG&E Corporation, and among themselves. The Utility and PG&E Corporation exchange administrative and professional services in support of operations. Services provided directly to PG&E Corporation by the Utility are priced at the higher of fully loaded cost (i.e., direct cost of good or service and allocation of overhead costs) or fair market value, depending on the nature of the services. Services provided directly to the Utility by PG&E Corporation are generally priced at the lower of fully loaded cost or fair market value, depending on the nature and value of the services. PG&E Corporation also allocates various corporate administrative and general costs to the Utility and other subsidiaries using agreed-upon allocation factors, including the number of employees, operating and maintenance expenses, total assets, and other cost allocation methodologies. Management believes that the methods used to allocate expenses are reasonable and meet the reporting and accounting requirements of its regulatory agencies.

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

	Year Ended December 31,		
(in millions)	**2009**	2008	2007
Utility revenues from:			
Administrative services provided to PG&E Corporation	**$ 5**	$ 4	$ 4
Interest from PG&E Corporation on employee benefit assets	**–**	–	1
Utility expenses from:			
Administrative services received from PG&E Corporation	**$62**	$122	$107
Utility employee benefit due to PG&E Corporation	**3**	2	4

At December 31, 2009 and December 31, 2008, the Utility had a receivable of $26 million and $29 million, respectively, from PG&E Corporation included in Accounts receivable – Related parties and Other Noncurrent Assets – Related parties receivable on the Utility's Consolidated Balance Sheets, and a payable of $16 million and $25 million, respectively, to PG&E Corporation included in Accounts payable – Related parties on the Utility's Consolidated Balance Sheets.

NOTE 16: COMMITMENTS AND CONTINGENCIES

PG&E Corporation and the Utility have substantial financial commitments in connection with agreements entered into to support the Utility's operating activities. PG&E Corporation and the Utility also have significant contingencies arising from their operations, including contingencies related to guarantees, regulatory proceedings, nuclear operations, environmental compliance and remediation, tax matters, and legal matters.

COMMITMENTS

UTILITY

Third-Party Power Purchase Agreements

As part of the ordinary course of business, the Utility enters into various agreements to purchase power and electric capacity. The price of purchased power may be fixed or variable. Variable pricing is generally based on the current market price of either gas or electricity at the date of purchase.

Qualifying Facility Power Purchase Agreements – Under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), electric utilities are required to purchase energy and capacity from independent power producers that are qualifying co-generation facilities and qualifying small power production facilities ("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 and 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 exceeds or fails to meet 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 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."

As of December 31, 2009, the Utility had agreements with approximately 240 QFs for approximately 3,900 MW that are in operation. Agreements for approximately 3,600 MW expire at various dates between 2010 and 2028. QF power purchase agreements for approximately 300 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 75 inoperative QFs. The total of approximately 3,900 MW consists of approximately 2,500 MW from cogeneration projects and approximately 1,400 MW from renewable sources. QF power purchase agreements accounted for 17%, 18%, and 20% of the Utility's 2009, 2008, and 2007 electricity sources, respectively. No single QF accounted for more than 5% of the Utility's 2009, 2008, or 2007 electricity sources.

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 2010 to 2031. The Utility's irrigation district and water agency contracts accounted for 3%, 2%, and 3%, of the Utility's electricity sources in 2009, 2008, and 2007, respectively. Irrigation districts and water agencies consist of small and large hydro plants. Purchases of electricity from small hydro plants are counted towards the Utility's renewable portfolio standard ("RPS") goal.

Renewable Energy Contracts – California law requires retail sellers of electricity, such as the Utility, to comply with an RPS by increasing their purchases of renewable energy (such as biomass, small hydroelectric, wind, solar, and geothermal energy), so that the amount of electricity delivered from eligible renewable resources equals at least 20% of their total retail sales by the end of 2010. If a retail seller is unable to meet its target for a particular year, the current CPUC "flexible compliance" rules allow the deficit to be carried forward for up to three years so that future deliveries of renewable power can be used to make up the deficit. The Utility has entered into various contracts to purchase renewable energy to help the Utility meet the current RPS requirement. In general, renewable contract payments consist primarily of per megawatt hour ("MWh") payments and either a small or no fixed capacity payment, as opposed to contracts with non-renewable sources, which generally include both a per MWh payment and a fixed capacity payment. As shown in the table below, the Utility's commitments for energy payments under these renewable energy agreements are expected to grow significantly, assuming that the facilities are timely developed. Renewable energy provided under these agreements contracts accounted for 7%, 5%, and 3% of the Utility's 2009, 2008, and 2007 electricity sources, respectively. No single supplier accounted for more than 5% of the Utility's 2009, 2008, or 2007 electricity sources.

Other Purchase Agreements – In accordance with the Utility's CPUC-approved long-term procurement plans, the Utility has entered into several power purchase agreements with third parties. The Utility's obligations under a portion of these agreements are contingent on the third party's development of a new generation facility to provide the power to be purchased by the Utility under the agreements.

Annual Receipts and Payments – The payments made under QFs, irrigation district and water agency, renewable energy, and other power purchase agreements during 2009, 2008, and 2007 were as follows:

(in millions)	2009	2008	2007
Qualifying facility energy payments	**$532**	$ 969	$ 812
Qualifying facility capacity payments	**334**	343	363
Irrigation district and water agency payments	**58**	69	72
Renewable energy and capacity payments	**706**	714	604
Other power purchase agreement payments	**643**	2,036	1,166

The amounts above do not include payments related to DWR purchases for the benefit of the Utility's customers, as the Utility only acts as an agent for the DWR.

At December 31, 2009, the undiscounted future expected power purchase agreement payments were as follows:

	Qualifying Facility		Irrigation District & Water Agency		Renewable (Other than QF)		Other		
(in millions)	Energy	Capacity	Operations & Maintenance	Debt Service	Energy	Capacity	Energy	Capacity	Total Payments
2010	$ 931	$ 395	$ 23	$ 51	$ 618	$ 8	$ 5	$ 252	$ 2,283
2011	845	365	21	55	855	8	6	289	2,444
2012	723	332	21	35	972	9	6	405	2,503
2013	701	322	15	27	913	9	6	431	2,424
2014	677	306	12	13	1,082	5	2	227	2,324
Thereafter	4,038	1,528	25	37	30,246	–	–	1,605	37,479
Total	$7,915	$3,248	$117	218	$34,686	$39	$25	$3,209	$49,457

Some of the power purchase agreements that the Utility entered into with independent power producers that are QFs are treated as capital leases. The following table shows the future fixed capacity payments due under the QF contracts that are treated as capital leases. (These amounts are also included in the table above.) The fixed capacity payments are discounted to their present value in the table below using the Utility's incremental borrowing rate at the inception of the leases. The amount of this discount is shown in the table below as the amount representing interest.

(in millions)	
2010	$ 50
2011	50
2012	50
2013	50
2014	42
Thereafter	162
Total fixed capacity payments	404
Less: amount representing interest	90
Present value of fixed capacity payments	$314

Minimum lease payments associated with the lease obligation are included in Cost of electricity on PG&E Corporation's and the Utility's Consolidated Statements of Income. The timing of the Utility's recognition of the lease expense conforms to the ratemaking treatment for the Utility's recovery of the cost of electricity. The QF contracts that are treated as capital leases expire between April 2014 and September 2021.

At December 31, 2009 and December 31, 2008, PG&E Corporation and the Utility had, respectively, $32 million and $30 million included in Current Liabilities – Other and $282 million and $314 million included in Noncurrent Liabilities – Other, representing the present value of the fixed capacity payments due under these contracts recorded on PG&E Corporation's and the Utility's Consolidated Balance Sheets. The corresponding assets at December 31, 2009 and December 31, 2008 of $314 million and $344 million, including amortization of $94 million and $64 million, respectively, are included in Property, Plant, and Equipment on PG&E Corporation's and the Utility's Consolidated Balance Sheets.

Natural Gas Supply, Transportation, and Storage Commitments

The Utility purchases natural gas directly from producers and marketers in both Canada and the United States to serve its core customers. The contract lengths and natural gas sources of the Utility's portfolio of natural gas procurement contracts can fluctuate based on market conditions. The Utility also contracts for natural gas transportation to transport natural gas from the points at which the Utility takes delivery (typically in Canada and the southwestern United States) to the points at which the Utility's natural gas transportation system begins. In addition, the Utility has contracted for gas storage services in order to better meet winter peak customer loads. At December 31, 2009, the Utility's undiscounted obligations for natural gas purchases, gas transportation services, and gas storage were as follows:

(in millions)	
2010	$ 660
2011	150
2012	62
2013	49
2014	44
Thereafter	115
Total	$1,080

Payments for natural gas purchases, gas transportation services, and gas storage amounted to $1.4 billion in 2009, $2.7 billion in 2008, and $2.2 billion in 2007.

Nuclear Fuel Agreements

The Utility has entered into several purchase agreements for nuclear fuel. These agreements have terms ranging from 1 to 16 years and are intended to ensure long-term fuel supply. The contracts for uranium and for conversion and enrichment services provide for 100% coverage of reactor requirements through 2014, while contracts for fuel fabrication services provide for 100% coverage of reactor requirements through 2011. The Utility relies on a number of international producers of nuclear fuel in order to diversify its sources and provide security of supply. Pricing terms are also diversified, ranging from market-based prices to base prices that are escalated using published indices. New agreements are primarily based on forward market pricing and will begin to impact nuclear fuel costs starting in 2010.

At December 31, 2009, the undiscounted obligations under nuclear fuel agreements were as follows:

(in millions)	
2010	$ 134
2011	100
2012	78
2013	118
2014	131
Thereafter	1,096
Total	$1,657

Payments for nuclear fuel amounted to $141 million in 2009, $157 million in 2008, and $102 million in 2007.

Other Commitments and Operating Leases

The Utility has other commitments relating to operating leases and SmartMeter™ deployment contracts. At December 31, 2009, the future minimum payments related to other commitments were as follows:

(in millions)	
2010	$ 40
2011	20
2012	19
2013	18
2014	14
Thereafter	26
Total	$137

Payments for other commitments and operating leases amounted to $22 million in 2009, $41 million in 2008, and $38 million in 2007. PG&E had operating leases on office facilities expiring at various dates from 2010 to 2018. Certain leases on office facilities contain escalation clauses requiring annual increases in rent ranging from 1% to 11%. The rentals payable under these leases may increase by a fixed amount each year, a percentage of a base year, or the consumer price index. Most leases contain extension options ranging between one and five years.

Underground Electric Facilities

At December 31, 2009, the Utility was committed to spending approximately $237 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 $40 million to $80 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 obligations of its former subsidiary, NEGT, that were issued to the purchaser of an NEGT subsidiary company in 2000. PG&E Corporation's primary 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 not received any claims nor does it consider it probable that any claims will be made under the guarantee. PG&E Corporation believes that its potential exposure under this guarantee would not have a material impact on its financial condition or results of operations.

UTILITY

Energy Efficiency Programs and Incentive Ratemaking

The CPUC has established a ratemaking mechanism to provide incentives to the California investor-owned utilities to meet the CPUC's energy savings goals through implementation of the utilities' energy efficiency programs. In accordance with this mechanism, the CPUC has awarded the Utility incentive revenues totaling $75 million through December 31, 2009 based on the energy savings achieved through implementation of the Utility's energy efficiency programs during the 2006 through 2008 program cycle.

Consistent with the incentive award process previously adopted by the CPUC, the CPUC held back an additional $40.3 million of incentive revenues, subject to the true-up process to be completed in 2010. The Utility has not recognized any portion of the $40.3 million held back in revenues. The CPUC adopted a schedule for the final true-up process that calls for a final decision by the end of 2010. PG&E Corporation and the Utility are unable to predict the amount, if any, of the $40.3 million holdback that the Utility may receive after the true-up process is completed.

Spent Nuclear Fuel Storage Proceedings

As part of the Nuclear Waste Policy Act of 1982, Congress authorized the U.S. Department of Energy ("DOE") and electric utilities with commercial nuclear power plants to enter into contracts under which the DOE would be required to dispose of the utilities' spent nuclear fuel and high-level radioactive waste no later than January 31, 1998, in exchange for fees paid by the utilities. In 1983, the DOE entered into a contract with the Utility to dispose of nuclear waste from the Utility's two nuclear generating units at Diablo Canyon and its retired nuclear facility at Humboldt Bay.

Because the DOE failed to develop a permanent storage site, the Utility obtained a permit from the NRC to build an on-site dry cask storage facility to store spent fuel through at least 2024. The construction of the dry cask storage facility is complete. During 2009 the Utility moved all the spent nuclear fuel that was scheduled to be moved into dry cask storage. An appeal of the NRC's issuance of the permit is still pending in the U.S. Court of Appeals for the Ninth Circuit. The appellants claim that the NRC failed to adequately consider environmental impacts of a potential terrorist attack at Diablo Canyon. It is uncertain when the appeal will be addressed by the Ninth Circuit.

As a result of the DOE's failure to build a repository for nuclear waste, the Utility and other nuclear power plant owners sued the DOE to recover costs that they incurred to build on-site spent nuclear fuel storage facilities. The Utility seeks to recover $92 million of costs that it incurred through 2004. After several years of litigation, in 2008 the U.S. Court of Appeals for the Federal Circuit ("Federal Circuit") issued an order clarifying the method to calculate damages to be awarded to the utilities for breach of their contracts by the DOE. Although the DOE has conceded that the Utility is entitled to recover approximately $82 million based on this method, the DOE continues to challenge the method in related litigation. In October 2009, a trial was held in the U.S. Federal Court of Claims to determine the amounts owed to the Utility based on the methodology approved by the Federal Circuit. The parties are waiting for the court to issue its decision. The Utility also will seek to recover costs incurred after 2004 to build on-site storage facilities.

PG&E Corporation and the Utility are unable to predict the amount and timing of any recoveries that the Utility will receive from the DOE. Amounts recovered from the DOE will be credited to customers.

Nuclear Insurance

The Utility has several types of nuclear insurance for the two nuclear operating units at Diablo Canyon and for its retired nuclear generation facility at Humboldt Bay Unit 3. The Utility has insurance coverage for property damages and business interruption losses as a member of Nuclear Electric Insurance Limited ("NEIL"). NEIL is a mutual insurer owned by utilities with nuclear facilities. NEIL provides property damage and business interruption coverage of up to $3.24 billion per incident for Diablo Canyon. In addition, NEIL provides $131 million of property damage insurance for Humboldt Bay Unit 3. Under this insurance, if any nuclear generating facility insured by NEIL suffers a catastrophic loss causing a prolonged outage, the Utility may be required to pay an additional premium of up to $39.7 million per one-year policy term.

NEIL also provides coverage for damages caused by acts of terrorism at nuclear power plants. Under the Terrorism Risk Insurance Program Reauthorization Act of 2007 ("TRIPRA"), acts of terrorism may be "certified" by the Secretary of the Treasury. For a certified act of terrorism, NEIL can obtain compensation from the federal government and will provide up to the full policy limits to the Utility for an insured loss. If one or more non-certified acts of terrorism cause property damage covered under any of the nuclear insurance policies issued by NEIL to any NEIL member, the maximum recovery under all those nuclear insurance policies may not exceed $3.24 billion within a 12-month period plus the additional amounts recovered by NEIL for these losses from reinsurance. (TRIPRA extends the Terrorism Risk Insurance Act of 2002 through December 31, 2014.)

Under the Price-Anderson Act, public liability claims from a nuclear incident are limited to $12.5 billion. As required by the Price-Anderson Act, the Utility purchased the maximum available public liability insurance of $300 million for Diablo Canyon. The balance of the $12.5 billion of liability protection is covered by a loss-sharing program among utilities owning nuclear reactors. Under the Price-Anderson Act, owner participation in this loss-sharing program is required for all owners of nuclear reactors that are licensed to operate, designed for the production of electrical energy, and have a rated capacity of 100 MW or higher. If a nuclear incident results in costs in excess of $300 million, then the Utility may be responsible for up to $117.5 million per reactor, with payments in each year limited to a maximum of $17.5 million per incident until the Utility has fully paid its share of the liability. Since Diablo Canyon has two nuclear reactors, each with a rated capacity of over 100 MW, the Utility may be assessed up to $235 million per incident, with payments in each year limited to a maximum of $35 million per incident. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due on or before October 29, 2013.

In addition, the Utility has $53.3 million of liability insurance for Humboldt Bay Unit 3 and has a $500 million indemnification from the NRC for public liability arising from nuclear incidents, covering liabilities in excess of the $53.3 million of liability insurance.

ENVIRONMENTAL MATTERS

The Utility may be required to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party under environmental laws. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances at various sites including, but not limited to, former manufactured gas plant ("MGP") sites, power plant sites, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous materials, even if the Utility did not deposit those substances on the site.

Given the complexities of the legal and regulatory environment and the inherent uncertainties involved in the early stages of a remediation project, the process for estimating remediation liabilities is subjective and requires significant judgment. The Utility records an environmental remediation liability when site assessments indicate that remediation is probable and it can reasonably estimate the loss within a range of possible amounts.

The Utility records an environmental remediation liability based on the lower end of the range of estimated costs, unless a more objective estimate can be achieved. Amounts recorded are not discounted to their present value.

The Utility had an undiscounted and gross environmental remediation liability of $586 million at December 31, 2009 and $568 million at December 31, 2008. The following table presents the changes in the environmental remediation liability from December 31, 2008:

(in millions)	
Balance at December 31, 2008	$568
Additional remediation costs accrued:	
Transfer to regulatory account for recovery	84
Amounts not recoverable from customers	20
Less: Payments	(86)
Balance at December 31, 2009	**$586**

The $586 million accrued at December 31, 2009 consists of the following:

- $46 million for remediation at the Utility's natural gas compressor site located near Hinkley, California;
- $158 million for remediation at the Utility's natural gas compressor site located in Topock, Arizona, near the California border;
- $86 million related to remediation at divested generation facilities;
- $113 million related to remediation costs for the Utility's generation and other facilities and for third-party disposal sites;
- $125 million related to investigation and/or remediation costs at former MGP 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 MGP sites); and
- $58 million related to remediation costs for fossil decommissioning sites.

The Utility recently contacted the owners of property located on three former MGP sites in urban, residential areas of San Francisco to offer to test the soil for residues, and depending on the results of such tests, to take appropriate remedial action. Until the Utility's investigation is complete, the extent of the Utility's obligation to remediate is established, and remedial actions are determined, the Utility is unable to determine the amounts it may spend in the future to remediate these sites. As a result, no amounts have been accrued for these sites (other than investigative costs).

The Utility expects to recover $291 million of the $586 million environmental remediation liability, in accordance with a CPUC-approved ratemaking mechanism under which the Utility is authorized to recover 90% of hazardous waste remediation costs without a reasonableness review. (Environmental remediation associated with the Hinkley natural gas compressor site is not recoverable under this mechanism.) In addition, the CPUC and the FERC have authorized the Utility to recover in rates approximately $130 million relating to remediation costs at fossil decommissioning sites and certain of the Utility's transmission stations. 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.

Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, estimated costs may vary significantly from actual costs, and the amount of additional future costs may be material to results of operations in the period in which they are recognized. The Utility's undiscounted future costs could increase to as much as $1 billion if the other potentially responsible parties are not financially able to contribute to these costs or if the extent of contamination or necessary remediation is greater than anticipated, and could increase further if the Utility chooses to remediate beyond regulatory requirements. In addition, it is reasonably possible that the Utility will incur losses related to certain MGP sites located in San Francisco but the Utility is unable to reasonably estimate the amount of such loss.

LEGAL MATTERS

PG&E Corporation and the Utility are subject to various laws and regulations and, in the normal course of business, PG&E Corporation and the Utility are named as parties in a number of claims and lawsuits.

PG&E Corporation and the Utility make a provision for a liability when it is both probable that a liability has been incurred and the amount of the loss can be reasonably estimated. These accruals, and the estimates of any additional reasonably possible losses, are reviewed quarterly and are adjusted to reflect the impacts of negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. In assessing such contingencies, PG&E Corporation's and the Utility's policy is to exclude anticipated legal costs.

The accrued liability for legal matters is included in PG&E Corporation's and the Utility's Current Liabilities – Other in the Consolidated Balance Sheets, and totaled $57 million at December 31, 2009 and $72 million at December 31, 2008. After consideration of these accruals, PG&E Corporation and the Utility do not expect that losses associated with legal matters will have a material adverse impact on their financial condition and results of operations.

QUARTERLY CONSOLIDATED FINANCIAL DATA (UNAUDITED)

				Quarter ended
(in millions, except per share amounts)	December 31	September 30	June 30	March 31
2009				
PG&E Corporation				
Operating revenues	**$3,539**	**$3,235**	**$3,194**	**$3,431**
Operating income	**523**	**607**	**656**	**513**
Income from continuing operations	**277**	**321**	**392**	**244**
Net income	**277**	**321**	**392**	**244**
Income available for common shareholders	**273**	**318**	**388**	**241**
Earnings per common share from continuing operations, basic	**0.72**	**0.84**	**1.03**	**0.65**
Earnings per common share from continuing operations, diluted	**0.71**	**0.83**	**1.02**	**0.65**
Net earnings per common share, basic	**0.72**	**0.84**	**1.03**	**0.65**
Net earnings per common share, diluted	**0.71**	**0.83**	**1.02**	**0.65**
Common stock price per share:				
High	**45.79**	**41.97**	**39.11**	**41.06**
Low	**39.74**	**36.59**	**34.60**	**34.50**
Utility				
Operating revenues	**$3,539**	**$3,235**	**$3,194**	**$3,431**
Operating income	**525**	**607**	**657**	**513**
Net income	**267**	**353**	**391**	**239**
Income available for common shareholders	**263**	**350**	**387**	**236**
2008				
PG&E Corporation				
Operating revenues	$3,643	$3,674	$3,578	$3,733
Operating income	545	639	584	493
Income from continuing operations	367	307	297	227
Net income	521	307	297	227
Income available for common shareholders	517	304	293	224
Earnings per common share from continuing operations, basic	0.98	0.83	0.80	0.62
Earnings per common share from continuing operations, diluted	0.97	0.83	0.80	0.62
Net earnings per common share, basic	1.39	0.83	0.80	0.62
Net earnings per common share, diluted	1.37	0.83	0.80	0.62
Common stock price per share:				
High	39.20	42.64	40.90	44.95
Low	29.70	36.81	38.09	36.46
Utility				
Operating revenues	$3,643	$3,674	$3,578	$3,733
Operating income	548	640	585	493
Net income	329	321	313	236
Income available for common shareholders	325	318	309	233

Management of PG&E Corporation and Pacific Gas and Electric Company ("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, 2009, 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, 2009.

Deloitte & Touche LLP, an independent registered public accounting firm, has audited the Consolidated Balance Sheets of PG&E Corporation and the Utility, as of December 31, 2009 and 2008; and PG&E Corporation's related consolidated statements of income, equity, and cash flows and the Utility's related consolidated statements of income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2009. As stated in their report, which is included in this annual report, Deloitte & Touche LLP also has audited PG&E Corporation's and the Utility's internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

To the Board of Directors and Shareholders of PG&E Corporation and Pacific Gas and Electric Company San Francisco, California

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, 2009 and 2008, and the Company's related consolidated statements of income, equity, and cash flows and the Utility's related consolidated statements of income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2009. We also have audited the Company's and the Utility's internal control over financial reporting as of December 31, 2009, 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 these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on these financial statements and an opinion on 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audits of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included 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, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of PG&E Corporation and subsidiaries and of Pacific Gas and Electric Company and subsidiaries as of December 31, 2009 and 2008, and the respective results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company and the Utility maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

DELOITTE & TOUCHE LLP

February 19, 2010
San Francisco, CA

BOARDS OF DIRECTORS OF PG&E CORPORATION AND PACIFIC GAS AND ELECTRIC COMPANY

David R. Andrews
Senior Vice President, Government Affairs, General Counsel, and Secretary, Retired, PepsiCo, Inc.

Lewis Chew
Senior Vice President, Finance and Chief Financial Officer, National Semiconductor Corporation

C. Lee Cox[1]
Vice Chairman, Retired, AirTouch Communications, Inc. and President and Chief Executive Officer, Retired, AirTouch Cellular

Peter A. Darbee
Chairman of the Board, Chief Executive Officer, and President, PG&E Corporation

Maryellen C. Herringer
Attorney-at-Law

Christopher P. Johns[2]
President, Pacific Gas and Electric Company

Roger H. Kimmel
Vice Chairman, Rothschild Inc.

Richard A. Meserve
President, Carnegie Institution of Washington

Forrest E. Miller
Group President-Corporate Strategy and Development, AT&T Inc.

Rosendo G. Parra
Senior Vice President, Retired, Dell Inc. and Partner and Co-Founder, Daylight Partners

Barbara L. Rambo
Chief Executive Officer, Taconic Management Services

Barry Lawson Williams
Managing General Partner, Retired, and President, Williams Pacific Ventures, Inc.

---

[1] C. Lee Cox is the non-executive Chairman of the Board of Pacific Gas and Electric Company.

[2] Christopher P. Johns is a director of Pacific Gas and Electric Company only.

PG&E CORPORATION OFFICERS

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

KENT M. HARVEY
Senior Vice President and
Chief Financial Officer

NANCY E. MCFADDEN
Senior Vice President and Senior Advisor to the Chairman and Chief Executive Officer

HYUN PARK
Senior Vice President and General Counsel

GREG S. PRUETT
Senior Vice President, Corporate Affairs

RAND L. ROSENBERG
Senior Vice President, Corporate Strategy and Development

JOHN R. SIMON
Senior Vice President, Human Resources

STEPHEN J. CAIRNS
Vice President, Internal Audit and Compliance

LINDA Y.H. CHENG
Vice President, Corporate Governance and Corporate Secretary

STEVEN L. KLINE
Vice President, Corporate Environmental and Federal Affairs and Chief Sustainability Officer

DINYAR B. MISTRY
Vice President and Controller

ANIL K. SURI
Vice President and Chief Risk and Audit Officer

GABRIEL B. TOGNERI
Vice President, Investor Relations

PACIFIC GAS AND ELECTRIC COMPANY OFFICERS

C. LEE COX
Non-executive Chairman of the Board

CHRISTOPHER P. JOHNS
President

DESMOND A. BELL
Senior Vice President, Shared Services and Chief Procurement Officer

THOMAS E. BOTTORFF
Senior Vice President, Regulatory Relations

HELEN A. BURT
Senior Vice President and Chief Customer Officer

JOHN T. CONWAY
Senior Vice President, Energy Supply and Chief Nuclear Officer

KENT M. HARVEY
Senior Vice President, Financial Services

JOHN S. KEENAN
Senior Vice President and Chief Operating Officer

PATRICIA M. LAWICKI
Senior Vice President and Chief Information Officer

GREG S. PRUETT
Senior Vice President, Corporate Affairs

EDWARD A. SALAS
Senior Vice President, Engineering and Operations

JOHN R. SIMON
Senior Vice President, Human Resources

FONG WAN
Senior Vice President, Energy Procurement

GEISHA J. WILLIAMS
Senior Vice President, Energy Delivery

WILLIAM D. ARNDT
Vice President, Transmission and Distribution Business Operations

OPHELIA B. BASGAL
Vice President, Community Relations

JAMES R. BECKER
Site Vice President, Diablo Canyon Power Plant

STEPHEN J. CAIRNS
Vice President, Internal Audit and Compliance

LINDA Y.H. CHENG
Vice President, Corporate Governance and Corporate Secretary

BRIAN K. CHERRY
Vice President, Regulatory Relations

SARA A. CHERRY
Vice President, Finance and Chief Financial Officer

DEANN HAPNER
Vice President, FERC and ISO Relations

WILLIAM H. HARPER, III
Vice President and Chief Diversity Officer

SANFORD L. HARTMAN
Vice President and Managing Director, Law

WILLIAM D. HAYES
Vice President, Gas Maintenance and Construction

ROBERT T. HOWARD
Vice President, Gas Transmission and Distribution

MARK S. JOHNSON
Vice President, Electric Operations and Engineering

GREGORY K. KIRALY
Vice President, Electric Maintenance and Construction

ROY M. KUGA
Vice President, Energy Supply Management

RANDAL S. LIVINGSTON
Vice President, Power Generation

STEVEN E. MALNIGHT
Vice President, Renewable Energy

PLACIDO J. MARTINEZ
Vice President, Engineering

DINYAR B. MISTRY
Vice President and Controller

ANIL K. SURI
Vice President and Chief Risk and Audit Officer

ALBERT F. TORRES
Vice President, Customer Operations

JANE K. YURA
Vice President, Regulation and Rates

For financial and other information about PG&E Corporation and Pacific Gas and Electric Company, please visit our websites, www.pgecorp.com and www.pge.com, respectively.

As of February 16, 2010, there were 81,642 holders of record of PG&E Corporation common stock. PG&E Corporation is the holder of all issued and outstanding shares of Pacific Gas and Electric Company common stock.

If you have questions about your PG&E Corporation common stock account or Pacific Gas and Electric Company preferred stock account, please write or call our transfer agent, BNY Mellon Shareowner Services ("BNY Mellon"):

BNY Mellon Shareowner Services
P. O. Box 358015
Pittsburgh, PA 15252-8015

Toll free telephone services:
1-800-719-9056 (Customer Services Representatives are available from 9:00 a.m. ET to 7:00 p.m. ET)
Website: www.bnymellon.com/shareowner/isd

If you have general questions about PG&E Corporation or Pacific Gas and Electric Company, please contact the Corporate Secretary's Office:

Vice President, Corporate Governance and Corporate Secretary
Linda Y.H. Cheng
PG&E Corporation
One Market, Spear Tower, Suite 2400
San Francisco, CA 94105-1126
415.267.7070
Fax 415.267.7268

Securities analysts, portfolio managers, or other representatives of the investment community should write or call the Investor Relations Office:

Vice President, Investor Relations
Gabriel B. Togneri
PG&E Corporation
One Market, Spear Tower, Suite 2400
San Francisco, CA 94105-1126
415.267.7080
Fax 415.267.7262

PG&E Corporation
General Information
415.267.7000

Pacific Gas and Electric Company
General Information
415.973.7000

Stock Exchange Listings
PG&E Corporation's common stock is traded on the New York and Swiss stock exchanges. The official New York Stock Exchange symbol is "PCG," but PG&E Corporation common stock is listed in daily newspapers under "PG&E" or "PG&E Cp."(1)

Pacific Gas and Electric Company has eight issues of preferred stock, all of which are listed on the NYSE Amex Equities stock exchange.

Issue	Newspaper Symbol(1)
First Preferred Cumulative, Par Value $25 Per Share	
Non Redeemable:	
6.00%	PacGE pfA
5.50%	PacGE pfB
5.00%	PacGE pfC
Redeemable:	
5.00%	PacGE pfD
5.00% Series A	PacGE pfE
4.80%	PacGE pfG
4.50%	PacGE pfH
4.36%	PacGE pfI

2010 Dividend Payment Dates

PG&E Corporation
January 15
April 15
July 15
October 15

Pacific Gas and Electric Company
February 15
May 15
August 15
November 15

Stock Held in Brokerage Accounts ("Street Name")
When you purchase your stock and it is held for you by your broker, the shares are listed with BNY Mellon in the broker's name, or street name. BNY Mellon does not know the identity of the individual shareholders who hold their shares in this manner. They simply know that a broker holds a number of shares that may be held for any number of investors. If you hold your stock in a street name account, you receive all tax forms, publications, and proxy materials through your broker. If you are receiving unwanted duplicate mailings, you should contact your broker to eliminate the duplications.

PG&E Corporation Dividend Reinvestment and Stock Purchase Plan ("DRSPP")
If you hold PG&E Corporation or Pacific Gas and Electric Company stock in your own name, rather than through a broker, you may automatically reinvest dividend payments from common and/or preferred stock in shares of PG&E Corporation common stock through the DRSPP. You may obtain a DRSPP prospectus and enroll by contacting BNY Mellon. If your shares are held by a broker in street name, you are not eligible to participate in the DRSPP.

Direct Deposit of Dividends
If you hold stock in your own name, rather than through a broker, you may have your common and/or preferred dividends transmitted to your bank electronically. You may obtain a direct deposit authorization form by contacting BNY Mellon.

Replacement of Dividend Checks
If you hold stock in your own name and do not receive your dividend check within 10 days after the payment date, or if a check is lost or destroyed, you should notify BNY Mellon so that payment can be stopped on the check and a replacement can be mailed.

Lost or Stolen Stock Certificates
If you hold stock in your own name and your stock certificate has been lost, stolen, or in some way destroyed, you should notify BNY Mellon immediately.

(1) Local newspaper symbols may vary.

PG&E CORPORATION
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL MEETINGS OF SHAREHOLDERS

Date: May 12, 2010

Time: 10:00 a.m.

Location: San Ramon Valley Conference Center
3301 Crow Canyon Road
San Ramon, California

FORM 10-K

If you would like a copy, free of charge, of PG&E Corporation's and Pacific Gas and Electric Company's joint Annual Report on Form 10-K for the year ended December 31, 2009, which has been filed with the Securities and Exchange Commission, please contact the Corporate Secretary's Office or visit our website at www.pgecorp.com/investors/financial_reports/.