EXHIBIT 3

PG&E

PG&E Corporation and Pacific Gas and Electric Company
2010 Annual Report

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A LETTER TO OUR STAKEHOLDERS FROM CHAIRMAN, CEO, AND PRESIDENT PETER A. DARBEE

Last year will long be remembered as one of the most difficult in our company's history, as we confronted and worked to overcome formidable challenges. Above all was the September 9 explosion on our natural gas pipeline in San Bruno, California, which tragically claimed eight lives, injured many more, destroyed or damaged dozens of homes, and shook many people's confidence in PG&E.

There are no words sufficient to fully convey my personal sadness at this tragedy. As we move forward to implement lessons learned from this accident and become a stronger and safer company, I know I can speak for everyone at PG&E when I say that the people whose lives have been impacted continue to be in all our thoughts and prayers.

This accident and other challenges in 2010 have made it clear that we have a long journey ahead to become the industry leader we aspire to be, and our team and I are more determined than ever to do what it takes to reach that goal.

Our pledge is that PG&E will ultimately emerge from this experience not simply as a better company, but rather as a standard-bearer for excellence among utilities. Indeed, we take seriously our responsibility to see that the lessons from this event not only help PG&E reach a new level of performance, but also help others in our industry to do the same.

Most of all, our resolve is focused on raising the standards for the way PG&E manages and operates its natural gas infrastructure. We are also committed to cultivating stronger relationships with our customers—beginning with restoring their trust in the safety and integrity of our system and operating practices.

As we pursue these goals, we are cooperating with our regulators, policy makers, and other stakeholders. As always, though, our success will also depend on the efforts of our 20,000 men and women. Their spirit of service has been the soul of PG&E for more than 100 years, and it has sustained us through the ups and downs that any long-lived company inevitably experiences.

Even amid last year's challenges, PG&E employees accomplished important goals on behalf of our customers. They re-inspected thousands of miles of natural gas lines in the wake of the San Bruno accident. They restored power following outages more quickly than any time in a decade and reduced the frequency of outages to the lowest level in more than two decades. They safely and efficiently brought two new power plants into operation. They achieved ambitious sustainability targets for reducing our energy and water use. And they helped our customers realize significant savings through further gains in energy efficiency.

But perhaps most telling, they came forward in overwhelming numbers to help victims of the San Bruno accident, providing PG&E with a strong presence in the community and putting a human face on our commitment to help residents recover and rebuild.

However, without diminishing the importance of these and other individual accomplishments, let it be said clearly that no one on our leadership team was satisfied with the sum of PG&E's performance in 2010.

The challenges encountered last year raised concerns among our customers, put strains on relationships, and, in some cases, hurt our standing in the eyes of valued stakeholders. Our team is working aggressively to reverse these setbacks and learn from these events.

Importantly, PG&E's longer-term performance results remain solid. In recent years we have made meaningful strides in areas from reliability and workplace safety to energy efficiency and environmental leadership. And, despite the impact of the challenges in 2010, we have delivered competitive returns for shareholders over the past several years.

This letter presents an overview of last year's accomplishments and challenges, together with insights into our plans for the current year and beyond as we work to regain our momentum and deliver the level of performance our stakeholders have rightly come to expect.

MAINTAINING SOLID FINANCIAL PERFORMANCE

As we do every year, in 2010 we again strove to see that PG&E continues to represent a solid investment opportunity. We recognize that only by consistently delivering on this requirement can we also see to it that PG&E is able to access new capital on the best terms for our customers and fund the substantial investments necessary to provide service on their behalf.

Once again last year, new capital investments in PG&E's utility asset base, together with incentives earned by helping customers realize significant energy efficiency savings goals, helped to drive growth in core earnings. However, the financial impacts of the San Bruno accident had an adverse effect on the company's earnings as reported in accordance with generally accepted accounting principles (GAAP).

On a GAAP basis, net income after dividends on preferred stock (also called "income available for common shareholders") was $1.10 billion, or $2.82 per share, for 2010. This compared with $1.22 billion, or $3.20 per share, for 2009.

The year-over-year decline in net income reflected San Bruno-related costs totaling $283 million on a pre-tax basis, or $0.43 per share. These costs included a $220 million provision for property damage, personal injury, and other third-party claims, as well as an additional $63 million in direct costs for providing support to the San Bruno community, re-inspecting natural gas lines, and other activities. Although we expect that most of the costs the utility incurs for third-party claims relating to the accident will ultimately be recovered through insurance, GAAP required us to record a charge equal to the low end of the estimated range for potential liability costs of $220 million to $400 million.

On an earnings from operations basis, a non-GAAP measure adjusted to reflect normal operations and exclude items like the accident-related costs, earnings per share rose 6.5 percent to $3.42, on earnings of $1.33 billion, compared to $3.21 per share, or $1.22 billion, in 2009. (The "Financial Highlights" table on page 7 reconciles GAAP total net income with non-GAAP earnings from operations.) These results were well within the company's 2010 guidance range of $3.35 per share to $3.50 per share for earnings from operations.

STRENGTHENING THE UTILITY'S INFRASTRUCTURE

We continued to invest substantially in our system last year, deploying $3.9 billion of new capital to expand and improve our gas and electric assets, strengthen safety and reliability, and meet the needs of new customers.

Within our electric distribution and transmission operations, a major focus was continuing to upgrade targeted transmission and distribution circuits and install new equipment to improve reliability. Additionally, we secured regulatory approval to invest an additional $357 million of capital through 2013 for PG&E's Cornerstone Improvement Program. This program aims to create more capacity and interconnectedness on the power grid, enabling us to better isolate power outages and redirect power flows onto neighboring circuits to restore service more quickly.

We also continued to invest in PG&E's natural gas system, with an emphasis on retrofitting or replacing older transmission and distribution pipe. This work has been a long-term priority, and in light of the San Bruno accident, we are accelerating and expanding many plans to reinforce our gas infrastructure.

The focal point for this work going forward is a proposed new 10-year pipeline modernization program, Pipeline 2020. Announced late last year, Pipeline 2020 is one of the most significant initiatives PG&E has ever launched, with ambitious goals and a sweeping scope.

Pipeline 2020 will propose to make targeted investments to test, inspect, and upgrade or replace parts of our transmission pipeline system, and to add remote-controlled or automatic shut-off valves in locations in our system where they can be effective. It will drive advancements in best practices across the industry and also includes funding to support new research into next-generation pipeline inspection technology. In addition, it encompasses efforts to create a new model for coordinating with local first responders and community leaders and increasing pipeline safety awareness.

In the coming months, we plan to share with California regulators our proposals for the first phase of this gas infrastructure modernization work that we believe is important to creating a safer and more reliable energy future for our customers.

In 2010, we also continued to grow PG&E's conventional electric generation portfolio as we began operations at the new units at our Humboldt Bay Generating Station and the new state-of-the-art Colusa Generating Station. We also received CPUC approval to purchase the Oakley Generating Station, a natural-gas-fired facility that is forecast to be the most efficient power plant of its kind in California when PG&E takes ownership, which is scheduled for 2016.

For the first time in our recent history, we also added renewable generation to our utility-owned portfolio with the inauguration of the Vaca-Dixon photovoltaic solar station. This represents the first major project under our five-year program to develop up to 500 megawatts of clean solar photovoltaic power, 250 megawatts of which will be owned by PG&E. When the entire program is online, we expect that it will provide enough renewable power each year to serve roughly 150,000 homes.

Finally, our Diablo Canyon nuclear power plant continues to provide safe, carbon-free electric power for our customers. As the regulatory process for relicensing this essential facility moves forward, our focus remains on ensuring safe and reliable operations.

Among last year's most notable accomplishments were settlements reached in PG&E's 2011 General Rate Case and its 2011 Gas Transmission and Storage Rate Case, both of which are now before the California Public Utilities Commission. The settlements, if approved, will provide revenue increases that will support critical new investments to enhance and expand service to customers. We also expect to be able to do this while minimizing rate increases for our customers.

IMPROVING OPERATIONAL PERFORMANCE

We continued to focus on improving PG&E's operational performance last year—a priority that has become even more pressing in view of the San Bruno accident.

Last year's results included gains in employee safety and service reliability—two benchmarks that we consider to be key barometers of overall operational performance. These results can be attributed to ongoing investments in our system, enhancements in training, and the adoption of improved procedures and practices.

OSHA recordable injuries were reduced by more than 20 percent compared with 2009 levels. We also cut motor vehicle safety incidents. Moreover, the 2010 results represented a continuation of comparably strong improvements in each of the last several years. That said, these gains were not enough to meet the targets we had set for ourselves in 2010.

Similarly, although the company improved electric reliability again last year, the progress fell short of our aggressive targets—even as electric outage duration in 2010 was the shortest in the last decade, and outage frequency was the lowest since 1988.

In 2011, we are redoubling our efforts in both safety and reliability, as is reflected in the higher targets we have once again set for ourselves.

In particular, reinforcing an uncompromising culture of safety will remain a top priority. Serious injuries still occurred far too frequently and two workers lost their lives in preventable accidents last year. This year, we are concentrating our attention on eliminating these most serious incidents, with our eyes still on the ultimate goal of zero injuries.

Closely linked and equally important to employee safety is our commitment and responsibility to public safety.

As noted earlier, we view the San Bruno accident and the findings that have emerged from the investigation thus far as clear signs that we must raise the bar on many of our natural gas system standards and practices. To assist us and leave no stone unturned in these efforts, we have assembled an experienced corps of leading outside advisors who are bringing their collective safety and operations expertise to this critical work. We are also undertaking a global search for an experienced senior gas executive to become PG&E's new senior vice president of gas operations. As lessons continue to emerge from the San Bruno accident, our pledge is that we will apply them aggressively to improve our pipeline operations.

ENGAGING WITH CUSTOMERS AND COMMUNITIES

As changes in our industry begin to reshape the utility customer experience, we believe a critical measure of our success will be our ability to engage customers effectively. Already, a growing number of consumers are relying on their energy providers to help them navigate an evolving landscape that includes high-tech smart grid devices, electric vehicles, distributed generation, and new rates based on dynamic pricing. And at least as many others are looking to their utilities to help them find new efficiencies and cope with cost pressures in the face of new economic realities.

We heard clearly from our customers last year that these were opportunities for improvement at PG&E, and we took a number of steps as a result.

Perhaps most significant, we ramped up customer outreach and customer education around PG&E's program to replace traditional gas and electric meters with 10 million new digital SmartMeter™ devices. These efforts came in response to concerns from customers and communities over the meters' accuracy and other issues.

SmartMeter™ devices offer customers more control over how they use gas and electricity and represent a foundational step toward a smarter grid that will leverage advanced communications, computing, and control technology to provide more affordable, reliable, and cleaner electrical service, as well as support the anticipated growth in electric vehicle use.

A thorough independent study last year confirmed the meters' precision. However, the study also pointed out a need for additional communications to consumers. We have since increased our outreach in a number of ways. For example, before SmartMeters™ are installed in any community, PG&E now holds open forums where customers can ask questions and see firsthand the meters' many advantages.

While we have been encouraged by the positive reception these increased outreach efforts have received in many areas, we are committed to continuing to work with those customers who still have questions about the new technology as we work to complete the program by our 2012 target.

These and other issues last year underscored that, to be fully successful, PG&E must work harder to stay ahead of customer concerns proactively. Indeed, our ability to do this will only become more important going forward.

In 2011, we are focused again on improving overall customer satisfaction, which fell during 2010 as reflected in ratings that were well below our targets. The San Bruno accident and SmartMeter™ concerns contributed heavily to these declines, as did PG&E's sponsorship of a controversial state ballot initiative defeated by voters last June. However, we recognize that these were not the only factors. Customers are also sending a signal that they expect PG&E to be more responsive to their service needs in general.

With that in mind, in the second half of last year, we initiated a system-wide listening tour in which PG&E officers and other members of management spent time in the field hearing candid—and sometimes difficult—feedback directly from our customers on a broad range of issues.

This outreach and engagement is continuing in 2011, and we are actively incorporating what we learn to help improve the way we are doing business.

We are also increasing PG&E's engagement within its communities. In 2010, PG&E employees volunteered 27,500 hours of their time, a 10 percent increase over 2009. They also set a new record for philanthropy through our annual charitable giving drive. And last year we again increased PG&E Corporation's charitable support in our communities, with contributions exceeding $19.3 million. In 2011, we will aim to build on these efforts once again.

INCREASING EFFICIENCY AND RENEWABLE ENERGY

Even in a year of challenge, PG&E's commitment to the environment has remained firm. MSCI/RiskMetrics, a leading investment research and advisory firm that evaluates investor risk and value related to sustainability issues, ranked PG&E number one on its 2010 global assessment of environmental attributes of 29 companies in the utility sector. In particular, PG&E was recognized for its low carbon emissions risk, overall sustainability management strategy, and strategic opportunities in renewable power and energy efficiency.

Newsweek magazine named PG&E the greenest utility in the country for the second consecutive year in 2010. We were again named to the Dow Jones Sustainability World Index, one of only five U.S. utilities to earn that distinction. And the Carbon Disclosure Project recognized PG&E as one of the top 10 companies in the S&P 500 for climate change-related disclosure and performance.

Our belief in the importance of environmental leadership has driven performance across our business, most notably in the areas of energy efficiency and renewable energy.

In 2010, our energy efficiency initiatives helped customers save over 250 megawatts of electricity and 23 million therms of natural gas, or the approximate amount of natural gas consumed by tens of thousands of average homes in our service area in one year. We also provided over $170 million in energy efficiency rebates, helping customers save money and providing additional stability to the electric grid through reduced demand.

Through our energy efficiency efforts, the company continued to earn significant incentives under the framework approved by the CPUC in which utilities share in the benefits of energy efficiency savings they help customers achieve. In December 2010, the CPUC awarded PG&E $29.1 million in incentives after a final review and consideration of the savings achieved by the company in its 2006–2008 program cycle, which is credited with saving $1.5 billion in energy costs.

PG&E's accomplishments were also solid on the renewable energy front. In 2010, we added about 290 megawatts of renewable energy to our supply, helping to increase our renewables deliveries to 17.7 percent of our total energy mix. PG&E also signed additional contracts to buy another 2,000 megawatts of renewable power in the future.

The additions to our supply will help PG&E achieve California's goals to significantly increase renewable energy deliveries over the next decade. The state's 33 percent target by 2020 is currently the most ambitious renewable energy goal in the country. Similarly, these efforts will also help the company as it works to meet requirements to reduce greenhouse gas emissions under California's landmark Global Warming Solutions Act.

As we pursue these goals, we remain fully committed to achieving results in ways that most effectively minimize the costs for utility customers.

LOOKING FORWARD

If, as we said in the opening of this letter, 2010 will be looked back on as a year in which we faced tremendous challenges, we are determined that it will also be remembered as a turning point—a pivotal moment that led us to rethink the way PG&E approaches key aspects of its business and raise its operational performance and service to set a new standard.

This determination will continue to drive us in 2011, and it will shape the way we continue to respond to the challenges that lie ahead.

Our priorities this year will continue to focus above all on the safety and integrity of our operations. As the investigations into the San Bruno tragedy move forward this year, we know we will gain more insights that will inform our efforts in this area. Our commitment is to apply them aggressively and take the appropriate steps to renew our customers' confidence in our system and practices.

We also will continue to actively reach out to customers to cultivate stronger relationships built on trust and confidence in PG&E. In everything we are doing today, we are striving to see PG&E through our customers' eyes and act in ways we would want to be served if we were in their shoes.

By succeeding in these two priorities, we will have a strong foundation to deliver on the responsibility we always have to create value for our investors.

We remain confident that PG&E's future is as full of opportunity as it has ever been. Even so, we understand that many of our stakeholders are watching closely—and perhaps even cautiously—as we move ahead.

Above all, we understand that your focus will rightly be on concrete action rather than words. On behalf of all 20,000 men and women of PG&E, we look forward to delivering results that will demonstrate our commitment and speak for themselves over the course of this year and beyond.

Sincerely,

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

March 14, 2011

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FINANCIAL HIGHLIGHTS [(1)]

PG&E Corporation

(unaudited, in millions, except share and per share amounts)		2010		2009
Operating Revenues	**$**	**13,841**	$	13,399
Income Available for Common Shareholders				
Earnings from operations [(2)]		**1,331**		1,223
Items impacting comparability [(3)]		**(232)**		(3)
Reported Consolidated Income Available for Common Shareholders		**1,099**		1,220
Income Per Common Share, Diluted				
Earnings from operations [(2)]		**3.42**		3.21
Items impacting comparability [(3)]		**(0.60)**		(0.01)
Reported Consolidated Net Earnings Per Common Share, Diluted		**2.82**		3.20
Dividends Declared Per Common Share		**1.82**		1.68
Total Assets at December 31,	**$**	**46,025**	$	42,945
Number of common shares outstanding at December 31,		**395,227,205**		371,272,457

(1) This is a combined annual report of PG&E Corporation and Pacific Gas and Electric Company ("Utility"). PG&E Corporation's Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries.

(2) "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.

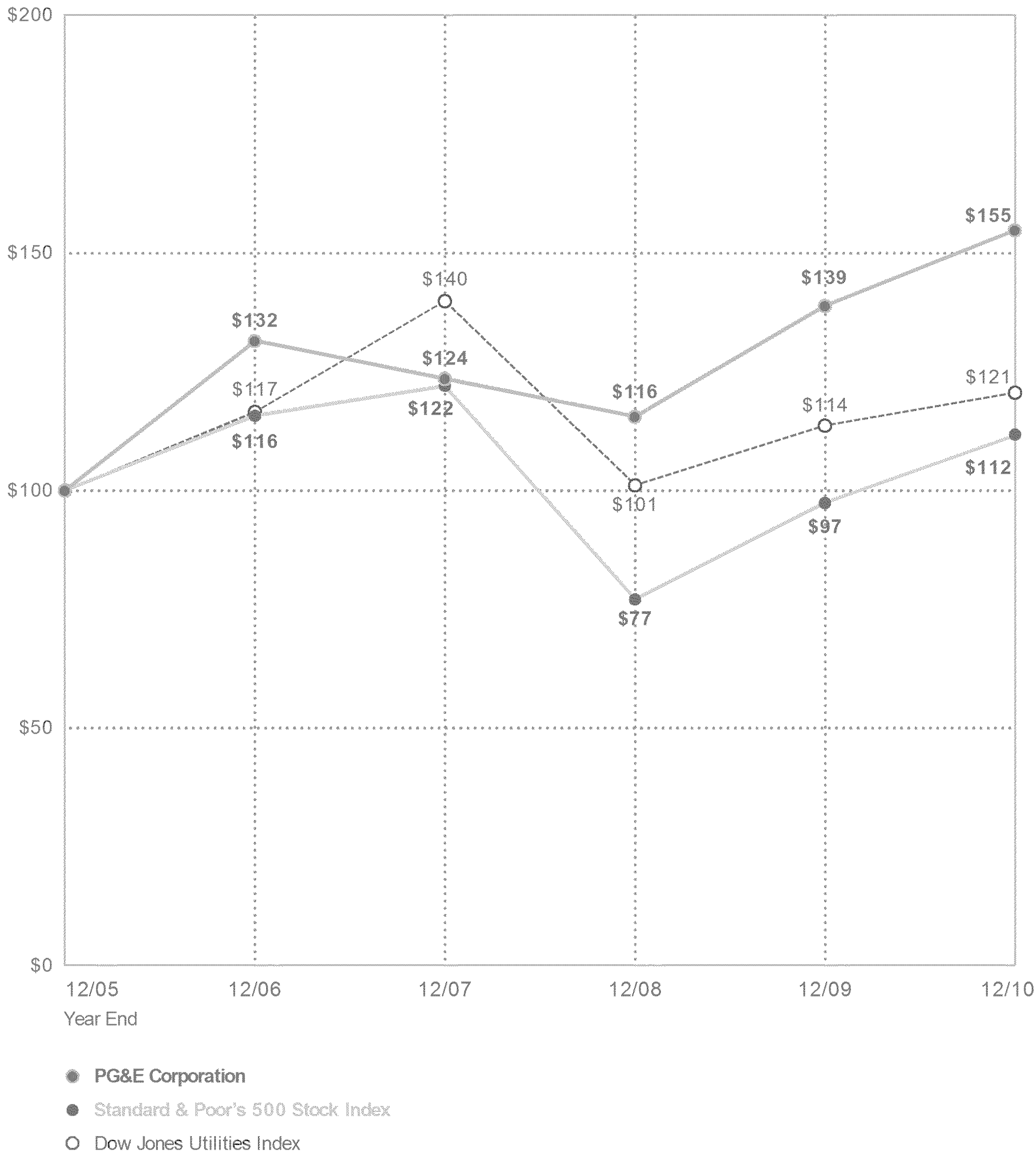
(3) "Items impacting comparability" represent items that management believes do not reflect the normal course of operations. PG&E Corporation's earnings from operations for 2010 exclude $168 million of costs, after tax, ($ 0.43) per common share, relating to the September 9, 2010 natural gas transmission pipeline accident in San Bruno, California. This amount primarily included a provision for estimated third-party claims for personal injury and property damage claims, and other damage claims, as well as costs incurred to provide immediate support to the San Bruno community, re-inspect the Utility's natural gas transmission lines, and perform other activities following the accident. Additionally, during 2010 the Utility spent $45 million, after-tax, ($0.12) per common share, to support a state-wide ballot initiative and recorded a charge of $19 million, ($0.05) per common share, triggered by the elimination of the tax deductibility of Medicare Part D federal subsidies.

PG&E Corporation's earnings from operations for 2009 excludes $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 the 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; and $38 million of severance costs, after-tax, ($0.10) per common share, related to the elimination of approximately 2% of the Utility's workforce.

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, 2005 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)	**2010**	2009	2008[1]	2007	2006
PG&E Corporation					
For the Year					
Operating revenues	**$ 13,841**	$ 13,399	$ 14,628	$ 13,237	$ 12,539
Operating income	**2,308**	2,299	2,261	2,114	2,108
Income from continuing operations	**1,113**	1,234	1,198	1,020	1,005
Earnings per common share from continuing operations, basic	**2.86**	3.25	3.23	2.79	2.78
Earnings per common share from continuing operations, diluted	**2.82** [2]	3.20	3.22	2.78	2.76
Dividends declared per common share [3]	**1.82**	1.68	1.56	1.44	1.32
At Year-End					
Common stock price per share	**$ 47.84**	$ 44.65	$ 38.71	$ 43.09	$ 47.33
Total assets	**46,025**	42,945	40,860	36,632	34,803
Long-term debt (excluding current portion)	**10,906**	10,381	9,321	8,171	6,697
Capital lease obligations (excluding current portion) [4]	**248**	282	316	346	376
Energy recovery bonds (excluding current portion) [5]	**423**	827	1,213	1,582	1,936
Pacific Gas and Electric Company					
For the Year					
Operating revenues	**$ 13,840**	$ 13,399	$ 14,628	$ 13,238	$ 12,539
Operating income	**2,314**	2,302	2,266	2,125	2,115
Income available for common stock	**1,107**	1,236	1,185	1,010	971
At Year-End					
Total assets	**45,679**	42,709	40,537	36,310	34,371
Long-term debt (excluding current portion)	**10,557**	10,033	9,041	7,891	6,697
Capital lease obligations (excluding current portion) [4]	**248**	282	316	346	376
Energy recovery bonds (excluding current portion) [5]	**423**	827	1,213	1,582	1,936

(1) Matters relating to discontinued operations are discussed in the section entitled "Results of Operations" within "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) See the discussion entitled "Summary of Changes in Earnings per Common Share and Income Available for Common Shareholders for 2010" within "Management's Discussion and Analysis of Financial Condition and Results of Operations."

(3) Information about the frequency and amount of dividends and restrictions on the payment of dividends is set forth in the section entitled "Liquidity and Financial Resources – Dividends" within "Management's Discussion and Analysis of Financial Condition and Results of Operations," and in PG&E Corporation's Consolidated Statements of Equity, the Utility's Consolidated Statements of Shareholders' Equity, and Note 6 of the Notes to the Consolidated Financial Statements.

(4) The capital lease obligations amounts are included in noncurrent liabilities – other in PG&E Corporation's and the Utility's Consolidated Balance Sheets.

(5) See Note 5 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. The Utility served approximately 5.2 million electric distribution customers and approximately 4.3 million natural gas distribution customers at December 31, 2010.

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 primary rate-setting proceeding at the CPUC is the general rate case ("GRC"), which occurs approximately every three years. The primary rate-setting proceeding at the FERC is the electric transmission owner ("TO") rate case, which occurs every year.

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 determines the capital structure the Utility must maintain (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, including a rate of return on equity ("ROE"). The CPUC has set the Utility's authorized ROE through 2011 at 11.35%. A change in ROE will be triggered if the 12-month October-through-September average yield for the applicable Moody's Investors Service 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 ability to recover the revenue requirements authorized by the CPUC in a 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. The Utility's ability to recover a portion of its 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 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, such as customer energy efficiency goals.

This is a combined annual report of PG&E Corporation and the Utility, and includes separate Consolidated Financial Statements for each of these two entities. PG&E Corporation's Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries. The Utility's Consolidated Financial Statements include the accounts of the Utility and its wholly owned and controlled subsidiaries. This combined Management's Discussion and Analysis of Financial Condition and Results of Operations ("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.

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 Pending Investigations of Natural Gas Explosions and Fires. On September 9, 2010, a Utility-owned natural gas pipeline ruptured in a residential area located in the City of San Bruno, California ("San Bruno accident") which resulted in the deaths of eight people, injuries to numerous individuals, and extensive property damage. Both the National Transportation Safety Board ("NTSB") and the CPUC are investigating the San Bruno accident. A cause of the pipeline rupture has not yet been determined. The investigations will examine various aspects of the operating, maintenance, and emergency response practices used in the Utility's natural gas operations, as well as the Utility's record-keeping and compliance with pipeline safety regulations. In addition, various civil lawsuits have been filed by residents of San Bruno in California state courts against PG&E Corporation and the Utility related to the San Bruno accident. (See "Legal Matters" below.) During 2010, the Utility recorded a total of $283 million of costs associated with the San Bruno accident, including a provision of $220 million for estimated third-party claims and $63 million of costs incurred to provide immediate support to the San Bruno community, re-inspect the Utility's natural gas transmission lines, and to perform other activities following the accident. The Utility estimates that it may incur as much as $400 million for third-party claims. (See Note 15 of the Notes to the Consolidated Financial Statements.) The total amount of third-party liability claims will depend on the final determination of the causes for the pipeline rupture and responsibility for the personal injuries and property damages, and the number and nature of third-party claims. Although PG&E Corporation and the Utility currently consider it likely that most of the costs the Utility incurs for third-party claims will ultimately be covered by its liability insurance, no amounts for insurance recoveries have been recorded as of December 31, 2010. The CPUC also has initiated an investigation of a natural gas explosion and fire that occurred on December 24, 2008 in a house located in Rancho Cordova, California ("Rancho Cordova accident"). The Utility expects that it will continue to incur unforecasted costs related to its natural gas operations as the investigations of the San Bruno and Rancho Cordova accidents progress, including costs to conduct an exhaustive review of records related to the Utility's natural gas transmission system and to perform pressure tests on portions of its natural gas transmission system. Further, if state or federal legislation that is being considered to address natural gas transmission operations and maintenance is enacted, the Utility may incur additional costs to comply with new statutory requirements. The Utility may not be able to recover these additional unforecasted costs through rates. (See "Operating and Maintenance Expenses" and "Pending Investigations" below.) Finally, PG&E Corporation's and the Utility's financial condition, results of operation, and cash flows may be affected by the amount of penalties and fines, if any, that may be imposed on the Utility related to these matters.

The Outcome of Ratemaking Proceedings. There are several rate cases that are currently pending at the CPUC and the FERC, the outcome of which will determine the majority of the Utility's base revenue requirements for 2011 and several years thereafter. These proceedings are discussed below under "Regulatory Matters." From time to time, the Utility also requests that the CPUC authorize additional base revenue requirements for specific capital expenditure projects such as new power plants. (See "Capital Expenditures" below.) The outcome of these proceedings can be affected by many factors, including general economic conditions, the level of customer rates, and political and regulatory policies. (See "Risk Factors" below.)

The Ability of the Utility to Control Operating Costs and Capital Expenditures. The Utility's revenue requirements are generally set by the CPUC and the FERC at a level to allow the Utility the opportunity to recover its forecasted operating expenses; to recover depreciation, tax, and interest expenses associated with forecasted capital expenditures; and to earn an ROE. Actual costs may differ from forecasts, or the Utility may incur significant unanticipated costs, such as costs related to storms, outages, or catastrophic events, or costs incurred to comply with regulatory orders or legislation.

Differences in the amount or timing of forecasted or authorized costs and actual costs can affect the Utility's ability to earn its authorized rate of return and the amount of PG&E Corporation's income available for common shareholders. (See "Capital Expenditures" below.) To the extent the Utility is unable to conclude that costs are probable of recovery through rates, the Utility will incur a charge to income. (See "Critical Accounting Policies" below.)

Authorized Capital Structure, Rate of Return, and Financing. The Utility's CPUC-authorized capital structure for its electric and natural gas distribution and electric generation rate base, consisting of 52% common equity and 48% debt and preferred stock, will remain in effect through 2012. The Utility's CPUC-authorized ROE of 11.35% will remain in effect through 2011 but is subject to change based on an annual adjustment mechanism described below under "Liquidity and Financial Resources." The timing and amount of the Utility's future debt financing will depend on the timing and amount of capital expenditures and other factors. PG&E Corporation contributes equity to the Utility as needed by the Utility to maintain its CPUC-authorized capital structure. PG&E Corporation may issue debt or equity to fund these equity contributions. (See "Liquidity and Financial Resources" below.)

SUMMARY OF CHANGES IN EARNINGS PER COMMON SHARE AND INCOME AVAILABLE FOR COMMON SHAREHOLDERS FOR 2010

PG&E Corporation's income available for common shareholders decreased by $121 million, or 10%, from $1,220 million in 2009 to $1,099 million in 2010. The following table is a summary reconciliation of the key changes in income available for common shareholders and earnings per common share for the year ended December 31, 2010:

	Earnings	Earnings Per Common Share (Diluted)
Income Available for Common Shareholders – 2009	**$ 1,220**	**$ 3.20**
San Bruno accident (1)	(168)	(0.43)
Tax refund (2)	(66)	(0.18)
Statewide ballot initiative (3)	(45)	(0.12)
Recovery of hydroelectric generation-related costs (4)	(28)	(0.07)
Federal health care law (5)	(19)	(0.05)
Rate base earnings (6)	88	0.23
Accelerated work on gas system (7)	59	0.16
Severance costs (8)	38	0.10
Other (9)	20	0.05
Increase in shares outstanding (10)	–	(0.07)
Income Available for Common Shareholders – 2010	**$ 1,099**	**$ 2.82**

(1) During 2010, the Utility recorded charges of $168 million, after-tax, for the San Bruno accident. These charges primarily included a provision for estimated third-party claims for personal injury and property damage claims, and other damage claims, as well as costs incurred to provide immediate support to the San Bruno community, re-inspect the Utility's natural gas transmission lines, and perform other activities following the accident.

(2) During 2009, PG&E Corporation recognized $66 million for the interest benefit associated with a federal tax refund.

(3) During 2010, the Utility contributed $45 million to support Proposition 16 – The Taxpayers Right to Vote Act.

(4) During 2009, the Utility recognized income of $28 million, after-tax, for the recovery of costs previously incurred in connection with its hydroelectric generation facilities.

(5) During 2010, the Utility recorded a charge of $19 million triggered by the elimination of the tax deductibility of Medicare Part D federal subsidies.

(6) During 2010, the Utility recognized earnings of $88 million, after-tax, attributable to the ROE on higher authorized capital investments.

(7) During 2009, the Utility incurred $59 million, after-tax, for costs to perform accelerated system-wide natural gas integrity surveys and associated remedial work.

(8) During 2009, the Utility accrued $38 million, after-tax, of severance costs related to the elimination of approximately 2% of its workforce.

(9) During 2010, the Utility incurred lower expenses for nuclear refueling outages, uncollectible customer accounts and disability costs, partially offset by a charge for SmartMeter™ related capital costs and higher storm and outage expenses.

(10) Represents the impact of a lower number of shares outstanding in 2009 compared to 2010; this has no dollar impact on earnings.

CAUTIONARY LANGUAGE REGARDING FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report. These forward-looking statements relate to, among other matters, estimated capital expenditures; estimated environmental remediation, tax, and other liabilities; estimates and assumptions used in PG&E Corporation's and the Utility's critical accounting policies; the anticipated outcome of various regulatory, governmental, and legal proceedings; estimated losses and insurance recoveries associated with the San Bruno accident; estimated future cash flows; and the level of future equity or debt issuances. These statements are also identified by words such as "assume," "expect," "intend," "plan," "project," "believe," "estimate," "target," "predict," "anticipate," "aim," "may," "might," "should," "would," "could," "goal," and "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 efficiently manage capital expenditures and its operating and maintenance expenses within authorized levels and timely recover its costs through rates;

the outcome of pending and future regulatory, legislative, or other proceedings or investigations, including the investigations by the NTSB and CPUC into the cause of the San Bruno accident and the safety of the Utility's natural gas transmission pipelines in its northern and central California service territory; the CPUC investigation of the Rancho Cordova accident; whether the Utility incurs civil or criminal penalties as a result of these proceedings; whether the Utility is required to incur additional costs for third-party liability claims or to comply with regulatory or legislative mandates which costs the Utility is unable to recover through rates or insurance; and whether the Utility incurs third-party liabilities or other costs in connection with service disruptions that may occur as the Utility complies with regulatory orders to decrease pressure in its natural gas transmission system;

reputational harm that PG&E Corporation and the Utility may suffer depending on the outcome of the various investigations, including those by the NTSB and the CPUC; the outcome of civil litigation; and the extent to which civil or criminal proceedings may be pursued by regulatory or governmental agencies;

the adequacy and price of electricity and natural gas supplies, the extent to which the Utility can manage and respond to the volatility of electricity and natural gas prices, and 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, human errors, 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 ("load") 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 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 environmental agencies with respect to the storage of spent nuclear fuel, security, safety, cooling water intake, or other matters associated with the operations at Diablo Canyon;

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 regulations, or their interpretation, on energy policy and the regulation of utilities and their holding companies;

whether the Utility can successfully complete its program to install advanced meters for its electric and natural gas customers, allay customer concerns about the new metering technology, and integrate the new meters with its customer billing and other systems while also implementing the system design changes necessary to accommodate retail electric rates based on dynamic pricing (i.e., electric rates that can vary with the customer's time of use and are more closely aligned with wholesale electricity prices) by the CPUC's due dates;

how the CPUC interprets and enforces the financial and other conditions imposed on PG&E Corporation when it became the Utility's holding company and the extent to which the interpretation or enforcement of these conditions has a material impact on PG&E Corporation;

the extent to which PG&E Corporation or the Utility incurs costs in connection with third-party claims or litigation, including those arising from the San Bruno accident, that are not recoverable through insurance, rates, 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 addressing the reduction of carbon dioxide and other greenhouse gases ("GHG"), water, the remediation of hazardous waste, and other matters, and whether the Utility is able to recover the costs of compliance with such laws, including the cost of emission allowances and offsets that the Utility may incur under federal or state cap-and-trade regulations;

the loss of customers due to various forms of bypass and competition, including municipalization of the Utility's electric distribution facilities, increasing levels of "direct access" by which consumers procure electricity from alternative energy providers, and implementation of "community choice aggregation," which permits cities and counties to purchase and sell electricity for their local residents and businesses; and

the outcome of federal or state tax audits and the impact of changes in federal or state tax laws, policies, or regulations, such as The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (the "Tax Relief Act").

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 2010, 2009, and 2008:

	Year ended December 31,		
(in millions)	**2010**	2009	2008
Utility			
Electric operating revenues	**$ 10,644**	$ 10,257	$ 10,738
Natural gas operating revenues	**3,196**	3,142	3,890
Total operating revenues	**13,840**	13,399	14,628
Cost of electricity	**3,898**	3,711	4,425
Cost of natural gas	**1,291**	1,291	2,090
Operating and maintenance	**4,432**	4,343	4,197
Depreciation, amortization, and decommissioning	**1,905**	1,752	1,650
Total operating expenses	**11,526**	11,097	12,362
Operating income	**2,314**	2,302	2,266
Interest income	**9**	33	91
Interest expense	**(650)**	(662)	(698)
Other income, net	**22**	59	28
Income before income taxes	**1,695**	1,732	1,687
Income tax provision	**574**	482	488
Net income	**1,121**	1,250	1,199
Preferred stock dividend requirement	**14**	14	14
Income Available for Common Stock	**$ 1,107**	$ 1,236	$ 1,185
PG&E Corporation, Eliminations, and Other (1)			
Operating revenues	**$ 1**	$ –	$ –
Operating expenses	**7**	3	5
Operating loss	**(6)**	(3)	(5)
Interest income	**–**	–	3
Interest expense	**(34)**	(43)	(30)
Other income (expense), net	**5**	8	(32)
Loss before income taxes	**(35)**	(38)	(64)
Income tax benefit	**(27)**	(22)	(63)
Loss from continuing operations	**(8)**	(16)	(1)
Discontinued operations (2)	**–**	–	154
Net income (loss)	**$ (8)**	$ (16)	$ 153
Consolidated Total			
Operating revenues	**$ 13,841**	$ 13,399	$ 14,628
Operating expenses	**11,533**	11,100	12,367
Operating income	**2,308**	2,299	2,261
Interest income	**9**	33	94
Interest expense	**(684)**	(705)	(728)
Other income (expense), net	**27**	67	(4)
Income before income taxes	**1,660**	1,694	1,623
Income tax provision	**547**	460	425
Income from continuing operations	**1,113**	1,234	1,198
Discontinued operations (2)	**–**	–	154
Net income	**1,113**	1,234	1,352
Preferred stock dividend requirement of subsidiary	**14**	14	14
Income Available for Common Shareholders	**$ 1,099**	$ 1,220	$ 1,338

(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. 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 2010, 2009, and 2008.

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' load is satisfied by electricity provided under long-term contracts between the California Department of Water Resources ("DWR") and various power suppliers. The commodity costs and associated revenues to recover the costs allocated to the Utility by the DWR are not included in the Consolidated Statements of Income.

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

(in millions)	**2010**	2009	2008
Revenues excluding pass-through costs	**$ 6,123**	$ 5,905	$ 5,562
Revenues for recovery of pass-through costs	**4,521**	4,352	5,176
Total electric operating revenues	**$ 10,644**	$ 10,257	$ 10,738

The Utility's total electric operating revenues, including revenues intended to recover costs that are passed through to customers, increased by $387 million, or 4%, in 2010 compared to 2009. Costs that are passed through to customers and do not impact net income increased by $169 million, primarily due to increases in the cost of electricity procurement partially offset by decreases in the cost of public purpose programs. (See "Cost of Electricity" below.) Electric operating revenues, excluding costs passed through to customers, increased by $218 million. This was primarily due to increases in authorized base revenues.

The Utility's total electric operating revenues, including revenues intended to recover costs that are passed through to customers, decreased by $481 million, or 4%, in 2009 compared to 2008. Costs that are passed through to customers and do not impact net income decreased by $824 million, primarily due to decreases in the costs of public purpose programs and electricity procurement. (See "Cost of Electricity" below.) Electric operating revenues, excluding costs passed through to customers, increased by $343 million. This was primarily due to $344 million of increases in authorized base revenues composed of an attrition increase (as approved in the last GRC covering 2007 through 2010) and increases in revenues to recover capital expenditures that have separately authorized by the CPUC.

The Utility's future electric operating revenues will be impacted by final authorization by the CPUC in the 2011 GRC and by the FERC in the TO rate cases. (See "Regulatory Matters" below.) The Utility also expects to continue to collect revenue requirements related to CPUC-approved capital expenditures outside the GRC, including capital expenditures for 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 Utility may earn incentive revenues under the existing energy efficiency ratemaking mechanism. (See "Regulatory Matters" below.)

Cost of Electricity

The Utility's mix of resources used to serve customers is determined by the availability of the Utility's own electricity generation, the amount of electricity supplied under the DWR's contracts allocated to the Utility's customers, and the cost-effectiveness of other third-party sources 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 own 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 operating the Utility's own generation facilities, which are included in operating and maintenance expense in the Consolidated Statements of Income.

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)	**2010**	2009	2008
Cost of purchased power	**$ 3,647**	$ 3,508	$ 4,261
Fuel used in own generation facilities	**251**	203	164
Total cost of electricity	**$ 3,898**	$ 3,711	$ 4,425
Average cost of purchased power per kWh (1)	**$ 0.081**	$ 0.082	$ 0.089
Total purchased power (in kWh)	**44,837**	42,767	47,668

(1) Kilowatt-hour

The Utility's total cost of electricity increased by $187 million, or 5%, in 2010 compared to 2009. This was caused by an increase in purchased power and an increase in the cost of fuel used in the Utility's own generation facilities as the Utility increased its non-nuclear generation to replace power that had previously been provided under a DWR contract that expired at the end of 2009 (costs associated with power provided to the Utility's customers under DWR contracts are not included in the Utility's cost of purchased power). The volume of purchased power is driven 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 decreased by $714 million, or 16%, in 2009 compared to 2008, primarily due to an 8% decrease in the average price 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.

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, 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, replaced, or renegotiated. Additionally, the cost of electricity is expected to continue reflecting the higher cost of procuring renewable energy as the Utility increases the amount of its renewable energy deliveries to comply with current and future California law and regulatory requirements. The Utility expects that it will be able to continue passing through the costs of its renewable energy purchase commitments to customers. (See "Environmental Matters – Renewable Energy Resources" and "Risk Factors" below.)

The Utility's future cost of electricity also will be affected by federal or state legislation or rules that may be adopted to regulate GHG emissions. (See "Environmental Matters – Climate Change" 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 Utility transports gas throughout its service territory by using its distribution system to deliver to end-use customers as well as 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 2010, core customers represented over 99% of the Utility's total customers and 39% of its total natural gas deliveries, while non-core customers comprised less than 1% of the Utility's total customers and 61% of its total natural gas deliveries.

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

(in millions)	**2010**	2009	2008
Revenues excluding pass-through costs	**$ 1,703**	$ 1,667	$ 1,616
Revenues for recovery of passed-through costs	**1,493**	1,475	2,274
Total natural gas operating revenues	**$ 3,196**	$ 3,142	$ 3,890

The Utility's natural gas operating revenues, including revenues intended to recover costs that are passed through to customers, increased by $54 million, or 2%, in 2010 compared to 2009. This reflects an $18 million increase in the costs that are passed through to customers and do not impact net income, primarily due to an increase in the cost of public purpose programs. Natural gas operating revenues, excluding costs passed through to customers, increased by $36 million, primarily due to an increase in authorized base revenue, partially offset by a decrease in natural gas storage revenues. (The Utility's storage facilities were at capacity throughout the year, and less gas was transported from storage due to the milder weather that prevailed. As result, the Utility was unable to accept more gas for storage.)

The Utility's total natural gas operating revenues, including revenues intended to recover costs that are passed through to customers, decreased by $748 million, or 19%, in 2009 compared to 2008. This reflects a $799 million decrease in the total cost of natural gas that is passed through to customers and generally does not impact net income. (See "Cost of Natural Gas" below.) Natural gas operating revenues, excluding costs passed through to customers, increased by $51 million, primarily due to an increase in authorized base revenues.

The Utility's future natural gas operating revenues will be impacted by final authorization by the CPUC in the 2011 GRC and the 2011 Gas Transmission and Storage rate case. Finally, the Utility may earn incentive revenues under the existing energy efficiency ratemaking mechanism. (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)	**2010**	2009	2008
Cost of natural gas sold	**$ 1,119**	$ 1,130	$ 1,955
Transportation cost of natural gas sold	**172**	161	135
Total cost of natural gas	**$ 1,291**	$ 1,291	$ 2,090
Average cost per Mcf [(1)] of natural gas sold	**$ 4.69**	$ 4.47	$ 7.43
Total natural gas sold (in millions of Mcf)	**249**	253	263

(1) One thousand cubic feet

The Utility's total cost of natural gas decreased by less than $1 million in 2010 compared to 2009. The Utility received $49 million in the first quarter of 2010 to be refunded to customers as part of a litigation settlement arising from the manipulation of the natural gas market by third parties during 1999 through 2002. The decrease resulting from the settlement was partially offset by an increase in transportation costs primarily due to attrition adjustments and an increase in procurement costs due to increases in the average market price of natural gas purchased.

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 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 natural 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; changes in the accrual for legal matters; 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 $89 million, or 2%, in 2010 compared to 2009. During 2010, the change in pass-through operating and maintenance costs as compared to 2009 was immaterial. The increase in operating and maintenance expenses was primarily due to $283 million of costs associated with the San Bruno accident. This amount includes a provision of $220 million for estimated third-party claims, including personal injury and property damage claims, damage to infrastructure, and other damage claims. (See Note 15 of the Notes to the Consolidated Financial Statements.) The additional $63 million of costs associated with the San Bruno accident were incurred to provide immediate support to the San Bruno community, re-inspect the Utility's natural gas transmission lines, and perform other activities following the accident. Additionally, operating and maintenance expenses increased due to a $36 million provision that was recorded for SmartMeter™ related capital costs that are forecasted to exceed the CPUC-authorized amount for recovery. (See "Regulatory Matters – Deployment of SmartMeter™ Technology" below.) These increases were partially offset by decreases of approximately $139 million in labor costs and other costs as compared to 2009, when costs were incurred in connection with an additional scheduled refueling outage at Diablo Canyon and accelerated natural gas leak surveys (and associated remedial work); $67 million in severance costs as compared to the same period in 2009, when charges were incurred related to the reduction of approximately 2% of the Utility's workforce; and $21 million in uncollectible customer accounts, as a result of customer outreach and increased collection efforts.

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 currently estimates that it may incur as much as $180 million for third-party claims related to the San Bruno accident in future years, in addition to the $220 million provision recorded in 2010. (See Note 15 of the Notes to the Consolidated Financial Statements.) The Utility also expects to continue to incur other costs related to the San Bruno accident, including costs to comply with CPUC orders and NTSB recommendations that have been issued in connection with the investigation of the San Bruno accident, such as costs to perform an exhaustive review of records related to the Utility's natural gas transmission system and to perform pressure tests on portions of its natural gas transmission system. The Utility currently estimates that these costs could range from approximately $200 million to $300 million for 2011. These estimates could change depending on a number of factors, including the outcome of the NTSB and CPUC investigations; the outcome of the "safety phase" of the Utility's 2011 Gas Transmission and Storage Rate Case; and the outcome of future rule-making, ratemaking, or investigatory proceedings at the CPUC. (See "Regulatory Matters" and "Pending Investigations" below.) In addition, current estimates could be affected by state and federal legislative requirements that may be adopted to establish operating practice standards for natural gas transmission operations and safety, to require the use of certain types of inspection methods and equipment, and to require the installations of certain types of valves. If this or similar legislation is enacted, the Utility may incur unforecasted costs to comply with new statutory requirements. PG&E Corporation and the Utility are uncertain whether all or a portion of the costs the Utility may incur to respond to orders, recommendations, or new legislative requirements would be recoverable through rates and the timing of any such recovery. Finally, if the CPUC institutes one or more formal investigations related to the San Bruno accident or the Utility's natural gas operating and maintenance practices in addition to the formal investigation of the Rancho Cordova accident, the CPUC may impose fines or penalties, which may be material, on the Utility if the CPUC determines that the Utility violated laws, rules, regulations, or orders.

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 $153 million, or 9%, in 2010 compared to 2009, primarily due to an increase in authorized capital additions.

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 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 $24 million, or 73%, in 2010 as compared to 2009, primarily due to lower interest rates affecting various regulatory balancing accounts and fluctuations in those accounts. In addition, interest income decreased as compared to 2009, when the Utility received interest income on previously incurred costs related to the proposed divestiture of its hydroelectric generation facilities.

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 13 of the Notes to the Consolidated Financial Statements.) 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 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 $12 million, or 2%, in 2010 as compared to 2009. This decrease was primarily attributable to decreases in the outstanding balances of the liability for Chapter 11 disputed claims, energy recovery bonds ("ERBs"), and various regulatory balancing accounts, and to lower interest rates on short-term debt. The decrease was partially offset by an increase in outstanding senior notes. (See Note 4 of the Notes to the Consolidated Financial Statements.)

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.

The Utility's interest expense in future periods will be impacted by changes in interest rates, changes in the liability for Chapter 11 disputed claims, changes in regulatory balancing accounts and regulatory assets, 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 decreased by $37 million, or 63%, in 2010 compared to 2009. The decrease was primarily due to a $45 million increase in other expenses as a result of costs the Utility incurred to support a California ballot initiative that appeared on the June 2010 ballot, which are not recoverable in rates. This expense was partially offset by a $15 million increase in allowance for equity funds used during construction, due to higher average balances of construction work in progress.

The Utility's other income, net increased by $31 million, or 111%, in 2009 compared to 2008, when the Utility incurred costs to oppose a California ballot initiative related to renewable energy and to oppose the City of San Francisco's municipalization efforts.

Income Tax Provision

The Utility's income tax provision increased by $92 million, or 19%, in 2010 compared to 2009. The effective tax rates were 34% and 28% for 2010 and 2009, respectively. The effective tax rate for 2010 increased as compared to the same period in 2009, when the Utility recognized state tax benefits arising from tax accounting method changes and benefits of various audit settlements at higher levels than 2010 settlements. The effective tax rate also increased due to the reversal of a deferred tax asset in the first quarter of 2010 that had previously been recorded to reflect the future tax benefits attributable to the Medicare Part D subsidy after 2012, which was eliminated as part of the federal health care legislation passed during March 2010. (See Note 9 of the Notes to the Consolidated Financial Statements.)

The Utility's income tax provision decreased by $6 million, or 1%, in 2009 compared to 2008. The effective tax rates were 28% and 29% 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 matters. (See Note 9 of the Notes to the Consolidated Financial Statements.)

The differences between the Utility's income taxes and amounts calculated by applying the federal statutory rate to income before income tax expense for continuing operations for 2010, 2009, and 2008 were as follows:

	2010	2009	2008
Federal statutory income tax rate	**35.0%**	35.0%	35.0%
Increase (decrease) in income tax rate resulting from:			
State income tax (net of federal benefit)	**1.0**	1.4	3.3
Effect of regulatory treatment of fixed asset differences	**(3.0)**	(2.6)	(3.1)
Tax credits	**(0.4)**	(0.5)	(0.5)
IRS audit settlements	**(0.2)**	(4.2)	(4.1)
Other, net	**1.5**	(1.3)	(1.7)
Effective tax rate	**33.9%**	27.8%	28.9%

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 PG&E Corporation's 9.5% Convertible Subordinated Notes, which were no longer outstanding at December 31, 2010, and 5.8% Senior Notes, and is not allocated to affiliates.

There were no material changes to PG&E Corporation's operating revenues and expenses in 2010 compared to 2009 and 2009 compared to 2008.

Other Income (Expense), Net

PG&E Corporation's other income, net decreased by $3 million, or 38%, in 2010 compared to 2009, primarily due to smaller investment-related gains in the rabbi trusts established in connection with the non-qualified deferred compensation plans. The investment-related gains resulted in a net increase to other income of $40 million, or 125%, in 2009 compared to 2008.

Income Tax Benefit

PG&E Corporation's income tax benefit increased by $5 million, or 23%, in 2010 primarily due to a write-off of a deferred tax asset in 2009, with no comparable amount in the current year.

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.

Discontinued Operations

In the fourth quarter of 2008, PG&E Corporation reached a settlement of federal tax audits for 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 Consolidated Financial Statements.) No similar amount was recognized in 2010 or 2009.

LIQUIDITY AND FINANCIAL RESOURCES

OVERVIEW

The Utility's ability to fund operations depends on the levels of its operating cash flows and access to the capital and credit markets. The levels of the Utility's operating cash and short-term debt fluctuate as a result of seasonal load 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. The CPUC 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 Utility has short-term borrowing 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, fund Utility equity contributions as needed for the Utility to maintain its CPUC-authorized capital structure, fund tax equity investments, and pay dividends primarily depends on the level of cash distributions received from the Utility and PG&E Corporation's access to the capital and credit markets.

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

	December 31,	
(in millions)	**2010**	2009
PG&E Corporation	**$ 240**	$ 193
Utility	**51**	334
Total consolidated cash and cash equivalents	**291**	527
Utility restricted cash	**563**	633
	$ 854	$ 1,160

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 and primarily invest their cash in money market funds.

Credit Facilities

The following table summarizes PG&E Corporation's and the Utility's revolving credit facilities at December 31, 2010:

(in millions)	Termination Date	Facility Limit	Letters of Credit Outstanding	Cash Borrowings	Commercial Paper Backup	Availability
PG&E Corporation	February 2012	**$ 187** (1)	**$ –**	**$ –**	**N/A**	**$ 187**
Utility	February 2012	**1,940** (2)	**329**	**–**	**$ 603**	**1,008**
Utility	February 2012	**750** (3)	**N/A**	**–**	**–**	**750**
Total credit facilities		**$ 2,877**	**$ 329**	**$ –**	**$ 603**	**$ 1,945**

(1) Includes an $87 million sublimit for letters of credit and a $100 million commitment 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 commitment for swingline loans.

(3) Includes a $75 million commitment for swingline loans.

For the year ended December 31, 2010, the average outstanding cash borrowings and commercial paper balance were $33 million and $655 million, respectively.

PG&E Corporation's and the Utility's credit agreements contain covenants that are usual and customary for credit facilities of this type, including covenants limiting liens, mergers, substantial asset sales, and other fundamental changes. Both the $750 million and the $1.9 billion revolving credit facilities require that the Utility maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% as of the end of each fiscal quarter. In addition, the $187 million revolving credit facility agreement requires that PG&E Corporation must own, directly or indirectly, at least 80% of the common stock and at least 70% of the voting capital stock of the Utility.

At December 31, 2010, PG&E Corporation and the Utility were in compliance with all covenants under each of the revolving credit facilities listed in the table above.

2010 FINANCINGS

PG&E Corporation

On November 4, 2010, PG&E Corporation entered into an Equity Distribution Agreement pursuant to which PG&E Corporation's sales agents may offer and sell, from time to time, PG&E Corporation common stock having an aggregate gross offering price of up to $400 million. Sales of the shares are made by means of ordinary brokers' transactions on the New York Stock Exchange, or in such other transactions as agreed upon by PG&E Corporation and the sales agents and in conformance with applicable securities laws. As of December 31, 2010, PG&E Corporation had issued 2,357,796 shares of common stock pursuant to the Equity Distribution Agreement for cash proceeds of $110 million, net of fees and commissions paid of $1 million.

In addition, during 2010, PG&E Corporation issued 5,105,505 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 $192 million of cash. PG&E Corporation issued 16,370,779 shares of common stock upon conversion of the $247 million principal amount of PG&E Corporation's Convertible Subordinated Notes at a conversion price of $15.09 per share between June 23 and June 29, 2010. These notes were no longer outstanding at December 31, 2010, and the conversion had no impact on cash.

Utility

The following table summarizes debt issuances in 2010. (See Note 4 of the Notes to the Consolidated Financial Statements.)

(in millions)	Issue Date	Amount
Senior Notes		
5.8%, due 2037	April 1	**$ 250**
3.5%, due 2020	September 15	**550**
Floating rate, due 2011	October 12	**250**
3.5%, due 2020	November 18	**250**
5.4%, due 2040	November 18	**250**
Total senior notes		**1,550**
Pollution control bonds		
Series 2010E, 2.25%, due 2026 (1)	April 8	**50**
Total debt issuances in 2010		**$ 1,600**

(1) These bonds bear interest at 2.25% per year through April 1, 2012; are subject to mandatory tender on April 2, 2012; and may be remarketed in a fixed or variable rate mode.

The net proceeds from the issuance of Utility senior notes in 2010 were used to repay outstanding commercial paper and for general corporate purposes. The net proceeds from the issuance of the pollution control bonds by the California Infrastructure and Economic Development Bank for the benefit of the Utility were used to fund capital investments and general working capital needs.

The Utility also received a contribution of $190 million of cash from PG&E Corporation during 2010 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 financings will depend on various factors, including:

the amount of cash internally generated through normal business operations;

the timing and amount of forecasted capital expenditures authorized in GRC or TO rate cases, or whether the CPUC approves the Utility's requests for specific capital projects outside of the GRC (discussed below under "Capital Expenditures");

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;

the timing and amount of payments made to third parties in connection with the San Bruno accident, and the timing and amount of related insurance recoveries;

the reduction in future tax payments as a result of legislation in December 2010 that allows for bonus depreciation on qualified property (discussed below under "Utility – Operating Activities"); and

the conditions in the capital markets, and other factors. (See Notes 13 and 15 of the Notes to the Consolidated Financial Statements.)

PG&E Corporation may issue debt or equity in the future to fund equity contributions to the Utility and to fund tax equity investments to the extent that internally generated funds are not sufficient. PG&E Corporation's financing needs depend primarily on the timing and amount of contributions made to the Utility to maintain the Utility's 52% common equity ratio authorized by the CPUC. Further, at December 31, 2010, PG&E Corporation made certain tax equity investments (see "PG&E Corporation" below) and may fund similar investments in the future, resulting in additional financing needs.

PG&E Corporation and the Utility have had continued access to the capital markets on reasonable terms and continue to believe that the Utility's cash flows from operations, existing sources of liquidity, and future financings will provide adequate resources to fund operating activities, meet anticipated obligations, make payments to third parties related to the San Bruno accident, and finance future capital expenditures and investments.

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 CPUC requires that the PG&E Corporation Board of Directors give first priority to 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, in setting the amount of dividends.

The Boards of Directors must also consider the CPUC requirement that the Utility maintain, on average, its CPUC-authorized capital structure, including a 52% equity component.

The following table summarizes PG&E Corporation's and the Utility's dividends paid:

(in millions)	**2010**	2009	2008
PG&E Corporation:			
Common stock dividends paid	**$ 662**	$ 590	$ 546
Common stock dividends reinvested in Dividend Reinvestment and Stock Purchase Plan	**18**	17	20
Utility:			
Common stock dividends paid	**$ 716**	$ 624	$ 568
Preferred stock dividends paid	**14**	14	14

On December 15, 2010, the Board of Directors of PG&E Corporation declared a quarterly dividend of $0.455 per share, totaling $183 million, which was paid on January 15, 2011 to shareholders of record on December 31, 2010. On February 16, 2011, the Board of Directors of PG&E Corporation declared a dividend of $0.455 per share, payable on April 15, 2011 to shareholders of record on March 31, 2011.

On December 15, 2010, 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, 2011 to preferred shareholders of record on January 31, 2011. On February 16, 2011, the Board of Directors of the Utility declared a cash dividend on its outstanding series of preferred stock, payable on May 15, 2011 to shareholders of record on April 29, 2011.

PG&E Corporation and the Utility each have revolving credit facilities that require the company to maintain a ratio of consolidated total debt to consolidated capitalization of at most 65%. This covenant, along with the CPUC's requirement for the Utility to maintain the 52% equity component of its capital structure, are considered to be restrictions on the payment of dividends. Based on the calculation of these ratios for each company, no amount of PG&E Corporation's retained earnings and $5.3 billion of the Utility's retained earnings were restricted at December 31, 2010.

In addition, the Utility was required to maintain at least $9.7 billion of its net assets as equity in order to maintain the capital structure of at least 52% equity at December 31, 2010. As a result, $9.7 billion of the Utility's net assets are restricted and may not be transferred to PG&E Corporation in the form of cash dividends.

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 2010, 2009, and 2008 were as follows:

(in millions)	**2010**	2009	2008
Net income	**$ 1,121**	$ 1,250	$ 1,199
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	**2,116**	1,927	1,838
Allowance for equity funds used during construction	**(110)**	(94)	(70)
Deferred income taxes and tax credits, net	**762**	787	593
Other	**46**	(27)	(6)
Effect of changes in operating assets and liabilities:			
Accounts receivable	**(105)**	157	(83)
Inventories	**(43)**	109	(59)
Accounts payable	**109**	(33)	(137)
Disputed claims and customer refunds	**–**	(700)	–
Income taxes receivable/payable	**(58)**	21	43
Other current assets	**(7)**	122	(187)
Other current liabilities	**130**	183	60
Regulatory assets, liabilities, and balancing accounts, net	**(394)**	(516)	(374)
Other changes in noncurrent assets and liabilities	**(331)**	(282)	(51)
Net cash provided by operating activities	**$ 3,236**	$ 2,904	$ 2,766

During 2010, net cash provided by operating activities increased $332 million compared to 2009. This increase reflects the Utility's payment to the California Power Exchange ("PX") in 2009, partially offset by net tax refunds that the Utility received in 2009 that were higher than the amount received in 2010. (The Utility's payment to the PX decreased the Utility's liability for the remaining net disputed claims that had been made in the Utility's Chapter 11 proceeding. See Note 13 of the Notes to the Consolidated Financial Statements.) The remaining changes in cash flows from operating activities consisted of fluctuations in activities within the normal course of business such as collateral, power purchases, and customer billings.

During 2009, net cash provided by operating activities increased $138 million compared to 2008. This increase reflects significantly lower commodity market prices in 2009 compared to 2008, which resulted in fewer cash outflows related to the timing of inventory and procurement activities. These net inflows were partially offset by the payment to the PX.

On December 17, 2010, the Tax Relief Act was signed into law, allowing qualified property placed into service after September 8, 2010, and before January 1, 2012, to be eligible for 100% bonus depreciation for tax purposes and qualified property placed into service in 2012 to be eligible for 50% bonus depreciation for tax purposes. (See Note 9 of the Notes to the Consolidated Financial Statements.) As a result, the Utility expects to make no federal tax payment in 2011. A reduction in the 2012 federal tax payment is expected; however, the amount cannot be reasonably estimated at this time. (See "Regulatory Matters – CPUC Resolution Regarding the Tax Relief Act" below.)

Additionally, there is uncertainty around the timing and amount of payments to be made to third parties in connection with the San Bruno accident, the timing and amount of related insurance recoveries, any penalties that may be assessed, costs associated with related investigations, and costs associated with changes to pipeline management and operations.

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 and the occurrence of storms and other events causing outages or damages to the Utility's infrastructure. 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. (See Note 11 of the Notes to the Consolidated Financial Statements.)

The Utility's cash flows from investing activities for 2010, 2009, and 2008 were as follows:

(in millions)	**2010**	2009	2008
Capital expenditures	**$ (3,802)**	$ (3,958)	$ (3,628)
Decrease in restricted cash	**66**	666	36
Proceeds from sales and maturities of nuclear decommissioning trust investments	**1,405**	1,351	1,635
Purchases of nuclear decommissioning trust investments	**(1,456)**	(1,414)	(1,684)
Other	**19**	11	1
Net cash used in investing activities	**$ (3,768)**	$ (3,344)	$ (3,640)

Net cash used in investing activities increased by $424 million in 2010 compared to 2009, primarily due to the Utility's $700 million payment to the PX, which decreased the restricted cash balance in 2009. (See Note 13 of the Notes to the Consolidated Financial Statements.) This increase was partially offset by a decrease in capital expenditures of $156 million as compared to 2009. Capital expenditures decreased in 2010 due to permitting delays, the postponement of purchases of materials that would otherwise have been capitalized earlier in the year, and poor weather conditions in the first half of 2010, which delayed construction activities as resources were re-directed to emergency response activities.

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 the Utility's payment to the PX, partially offset by an increase of $330 million in capital expenditures. The increase in capital expenditures in 2009 compared to 2008 was due to the increase in installation of 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 the timing and amount of 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 2010, 2009, and 2008 were as follows:

(in millions)	**2010**	2009	2008
Borrowings under revolving credit facilities	**$ 400**	$ 300	$ 533
Repayments under revolving credit facilities	**(400)**	(300)	(783)
Net issuances of commercial paper, net of discount of $3 in 2010 and 2009, and $11 in 2008	**267**	43	6
Proceeds from issuance of short-term debt, net of issuance costs of $1 in 2010 and 2009	**249**	499	–
Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $23 in 2010, $25 in 2009, and $19 in 2008	**1,327**	1,384	2,185
Short-term debt matured	**(500)**	–	–
Long-term debt matured or repurchased	**(95)**	(909)	(454)
Energy recovery bonds matured	**(386)**	(370)	(354)
Preferred stock dividends paid	**(14)**	(14)	(14)
Common stock dividends paid	**(716)**	(624)	(568)
Equity contribution	**190**	718	270
Other	**(73)**	(5)	(36)
Net cash provided by financing activities	**$ 249**	$ 722	$ 785

In 2010, net cash provided by financing activities decreased by $473 million compared to 2009. In 2009, net cash provided by financing activities decreased by $63 million compared to 2008. 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

As of December 31, 2010, PG&E Corporation's affiliates had entered into four tax equity agreements with two privately held companies to fund residential and commercial retail solar energy installations. Under these agreements, PG&E Corporation will provide payments of up to $300 million, and in return, receive the benefits of local rebates, federal investment tax credits or grants, and a share of these companies' customer payments. PG&E Corporation could be required to pay up to an additional $41 million in the event that its ownership interests are liquidated when in a deficit position. (See Note 2 of the Notes to the Consolidated Financial Statements.) However, PG&E Corporation's financial exposure for these arrangements is generally limited to its lease payments and investment contributions to these companies. As of December 31, 2010, PG&E Corporation had made total payments of $149 million under these tax equity agreements. Lease payments and investment contributions are included in cash flows from operating and investing activities, respectively, within the Consolidated Statements of Cash Flows.

In addition to the investments above, PG&E Corporation had the following material cash flows on a stand-alone basis for the years ended December 31, 2010, 2009, and 2008: dividend payments, interest payments, common stock issuance, the senior note issuance of $350 million in March 2009, net tax refunds of $189 million in 2009, and transactions between PG&E Corporation and the Utility.

CONTRACTUAL COMMITMENTS

The following table provides information about PG&E Corporation's and the Utility's contractual commitments at December 31, 2010.

	Payment due by period				
(in millions)	Less Than 1 Year	1–3 Years	3–5 Years	More Than 5 Years	**Total**
Contractual Commitments:					
Utility					
Long-term debt (1):					
Fixed rate obligations	$ 1,085	$ 1,598	$ 2,026	$ 16,104	**$ 20,813**
Variable rate obligations	312	635	47	307	**1,301**
Energy recovery bonds	435	436	–	–	**871**
Purchase obligations (4):					
Power purchase agreements (2):					
Qualifying facilities	1,086	1,720	1,617	4,392	**8,815**
Renewable contracts	804	2,223	3,589	40,887	**47,503**
Irrigation district and water agencies	80	109	47	43	**279**
Other power purchase agreements	694	1,512	1,189	4,227	**7,622**
Natural gas supply and transportation	710	464	331	1,128	**2,633**
Nuclear fuel	84	174	323	1,057	**1,638**
Pension and other benefits (3)	369	862	903	451 (6)	**2,585**
Capital lease obligations (4)	50	100	80	124	**354**
Operating leases (4)	25	41	25	73	**164**
Preferred dividends (5)	14	28	28	–	**70**
PG&E Corporation					
Long-term debt (1):					
Fixed rate obligations	20	40	355	–	**415**

(1) Includes interest payments over the terms of the debt. Interest is calculated using the applicable interest rate at December 31, 2010 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 that 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.) For information on energy recovery bonds, see Note 5 of the Notes to the Consolidated Financial Statements.

(2) This table includes power purchase agreements with plants currently under construction and assumes plants will become operational. This table does not include DWR-allocated contracts because the DWR is legally and financially responsible for these contracts and payments.

(3) PG&E Corporation's and the Utility's funding policy is to contribute tax-deductible amounts, consistent with applicable regulatory decisions, sufficient to meet minimum funding requirements. (See Note 12 of the Notes to the Consolidated Financial Statements.)

(4) See Note 15 of the Notes to the Consolidated Financial Statements.

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

(6) Payments into the pension and other benefits plans are based on annual contribution requirements. As these annual requirements continue indefinitely into the future, the amount reflected represents only one year of contributions for the Utility's pension, pension benefit obligation plans, and long-term disability plans.

The contractual commitments table above excludes potential commitments associated with the conversion of existing overhead electric facilities to underground electric facilities. At December 31, 2010, the Utility was committed to spending approximately $236 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 communication utilities involved. The Utility expects to spend approximately $42 million to $60 million each year in connection with these projects. Consistent with past practice, the Utility expects that these capital expenditures will be included in rate base as each individual project is completed and recoverable in rates charged to customers.

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.

CONTINGENCIES

PG&E Corporation and the Utility have significant contingencies, including Chapter 11 disputed claims, claims arising from the San Bruno accident, tax matters, legal matters, and environmental matters, which are discussed in Notes 9, 13, and 15 of the Notes to the Consolidated Financial Statements.

CAPITAL EXPENDITURES

UTILITY

The Utility's capital expenditures for property, plant, and equipment totaled $3.9 billion in 2010, $3.9 billion in 2009, and $3.7 billion in 2008. The Utility expects that capital expenditures will total approximately $3.7 billion in 2011. 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.

The Utility makes various capital investments in its electric generation and 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 authorizes 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.)

In addition, from time to time, the CPUC authorizes the Utility to collect additional revenue requirements to recover capital expenditures related to specific projects. During 2010, the Utility incurred capital expenditures relating to specific CPUC-authorized projects, including the continuing installation of advanced electric and gas meters using SmartMeter™ technology, electric and gas distribution reliability improvements, and the construction of the new Colusa Generation Station, which commenced operations in December 2010. The CPUC also has authorized the Utility to develop renewable generation facilities using photovoltaic technology. Other projects are discussed 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 OAKLEY GENERATION FACILITY

On December 16, 2010, the CPUC voted to permit the Utility to enter into an amended purchase and sale agreement with Contra Costa Generating Station LLC for the development and construction of the 586-megawatt ("MW") Oakley Generating Station, a natural gas-fired, combined-cycle generation facility proposed to be located in Oakley, California. Under the amended agreement, the guaranteed commercial availability date has been shifted from June 1, 2014 to June 1, 2016. Under the CPUC decision, if the Utility acquires the facility before January 1, 2016, the Utility's associated costs cannot be recovered through rates until after January 1, 2016. Instead, the Utility's ability to recover its costs before January 1, 2016 would depend on the amount of electric generation revenues produced by the facility. If the Utility acquires the facility after January 1, 2016, the Utility's associated costs would be recoverable through rates. The Utility and the developer are currently negotiating an additional amendment to the purchase and sale agreement to reflect the CPUC's decision. The Utility is uncertain whether and when the proposed amendment will be executed.

During January 2011, several parties filed applications for rehearing of the CPUC decision. PG&E Corporation and the Utility are unable to predict whether the CPUC will modify its decision based on these applications.

PROPOSED MANZANA WIND FACILITY

On December 21, 2010, a proposed decision was issued in the CPUC proceeding to consider the Utility's December 2009 application for approval of a purchase and sales agreement for the proposed 246 MW Manzana wind project and for authority to recover the estimated capital costs of $911 million in rates. On January 14, 2011, the counterparty to the agreement gave the Utility notice that it was exercising its right to terminate the agreement. On January 19, 2011, the Utility requested that the CPUC permit the Utility to withdraw the original application. It is uncertain whether or when the CPUC will grant the Utility's request to withdraw the application.

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, other than those discussed in Note 2 (PG&E Corporation's tax equity financing agreements) and Note 15 of the Notes to the Consolidated Financial Statements (the Utility's commodity purchase agreements).

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

On October 15, 2010, the Utility, together with the CPUC's Division of Ratepayer Advocates ("DRA"), The Utility Reform Network ("TURN"), Aglet Consumer Alliance, and nearly all other intervening parties, filed a motion with the CPUC seeking approval of a settlement agreement to resolve almost all of the issues raised by the parties in the Utility's 2011 GRC. Although the CPUC has not yet issued a final decision in the GRC proceeding, on November 19, 2010, the CPUC authorized the revenues to be approved in the CPUC's final decision to become effective as of January 1, 2011. PG&E Corporation and the Utility are unable to predict whether the CPUC will approve the settlement agreement.

Revenue Requirements

The settlement agreement proposes that the Utility's total 2011 revenue requirements be increased by $395 million, including $103 million related to depreciation rate changes. In addition, the settlement agreement proposes to (1) establish a new balancing account for meter reading costs outside of the GRC that offsets $113 million requested in the GRC application and (2) remove $30 million of requested revenue requirements from the GRC for consideration in other ratemaking proceedings. Furthermore, approximately $44 million of the revenue requirement the Utility requested in the GRC application remains subject to litigation in the GRC.

The following table shows the differences, based on cost category, between the revenue requirements requested in the GRC application and the amount proposed in the settlement agreement:

(in millions)	Amounts Requested in the GRC Application	Amounts Proposed in the Settlement Agreement	Difference
Operations and maintenance	$ 1,437	$ 1,308	$ (129)
Customer services	498	329	(169)
Administrative and general	857	768	(89)
Less: Revenue credits	(151)	(149)	2
Franchise fees and uncollectible customer accounts, taxes (other than income taxes), and other adjustments	188	120	(68)
Depreciation, return, and income taxes	3,817	3,601	(216)
Total Revenue Requirements	$ 6,646	$ 5,977	$ (669)

The following paragraphs describe the revenue requirement reductions proposed in the settlement agreement compared to the amounts requested in the GRC application:

The $129 million reduction in revenue requirements for operations and maintenance costs reflects a lower forecast of costs for, among other items, customer assistance services related to new customer connections, vegetation management, and development of utility-owned renewable generation.

The $169 million reduction in revenue requirements for customer services costs reflects the reduction of costs related to such items as customer retention and economic development efforts, dynamic pricing, and meter reading. While the Utility's GRC application requested recovery of $113 million for meter reading costs in 2011, the settlement agreement proposes that these costs will instead be recovered via a new balancing account. The balancing account would track and recover incurred meter reading costs, subject to a cap of $76 million, and the Utility also would retain the cost savings attributable to decreased meter reading costs due to the installation of SmartMeter™ devices. The total of the balancing account recovery plus retained cost savings is estimated to approximate the $113 million originally requested.

The $89 million reduction in administrative and general costs reflects lower funding for various PG&E Corporation and Utility corporate service functions and lower funding for employee incentive compensation. The Utility also agreed to seek recovery of $5 million of costs incurred in connection with the sale of property in another proceeding rather than the GRC.

The $68 million reduction in revenue requirements relating to franchise fees and uncollectible customer accounts, taxes (other than income), and other adjustments includes $44 million related to return and income taxes on the Utility's unrecovered investment in conventional electric meters that have been replaced by SmartMeter™ devices. The parties have agreed that this part of the Utility's request will be litigated as part of the GRC proceeding. If the Utility is successful, the $44 million will be added back to the Utility's 2011 electric distribution revenue requirement. The settlement agreement also would adopt a higher uncollectible revenue factor that would be used in another CPUC proceeding to determine the amount of revenue the Utility can collect to offset uncollectible customer accounts. This is expected to result in additional revenues of approximately $4 million.

The $216 million reduction in revenue requirements for depreciation, return, and income taxes consists of a

$105 million decrease driven by lower depreciation rates and a $110 million decrease related to lower capital expenditures and other rate base adjustments. About $49 million of the $110 million reduction is related to the treatment of nuclear fuel and fuel oil inventory balances. Under the settlement agreement, the Utility agreed to continue recovering carrying costs on these balances at short-term interest rates (estimated to be $1 million per year based on current rates) through the energy resource recovery balancing account ("ERRA"), in accordance with the current regulatory treatment of these costs, rather than as part of the authorized GRC rate base. Another $20 million of the reduction relates to costs to implement the California Independent System Operator's Market Redesign and Technology Update ("MRTU"). Consistent with the settlement agreement, the Utility plans to seek recovery of MRTU-related costs through the ERRA or other proceedings.

In summary, the settlement agreement proposes revenue requirements of $3.2 billion for electric distribution (as compared to $3.5 billion included in the GRC application), $1.1 billion for natural gas distribution (as compared to $1.3 billion included in the GRC application), and $1.7 billion for electric generation operations (as compared to $1.8 billion included in the GRC application).

Attrition Year Revenues
The settlement agreement proposes an attrition increase of $180 million to the authorized 2011 revenues in 2012 and an additional increase of $185 million in 2013. On a comparable basis, the Utility had requested an attrition mechanism estimated to provide increases of approximately $262 million in 2012 and approximately $334 million in 2013.

Balancing Accounts
The settlement agreement proposes to establish a new "one-way" balancing account for the Utility to recover up to approximately $20 million per year for costs associated with the Utility's natural gas distribution integrity management program. If these costs are not spent during the GRC period, the unspent funds must be refunded to customers. However, customers would not be required to pay for costs in excess of the annual $20 million cost cap. The proposed decision also would allow the Utility to remove $113 million in forecast meter reading costs from the requested GRC revenue requirements. Instead, the Utility would record actual meter reading costs up to an annual cap of $76 million in a new "one-way" meter reading balancing account. With the exception of this proposed new "one-way" balancing account and the proposed meter reading balancing account discussed above, the settlement agreement proposes to retain the existing balancing account structure without any substantial changes.

Capital Additions and Rate Base
The settlement agreement is consistent with capital expenditures for 2011 through 2013 averaging $2.2 billion to $2.3 billion per year for the portions of the Utility's business addressed in the GRC. Proposed capital expenditures are lower than the amount included in the Utility's GRC application, which averaged $2.7 billion per year, based on a lower forecast for new customer connections and lower capital expenditures for hydroelectric generation facilities, information technology systems, and fleet replacement. The ultimate amounts of capital expenditures will depend on a number of factors, including the level of operations and maintenance, administrative and general, and other costs.

The settlement agreement proposes a 2011 annual average rate base of $16.6 billion for the portions of the Utility's business reviewed in the GRC compared with the Utility's request of $17.2 billion. The $0.6 billion difference is based on the capital expenditure reductions described above, the removal of MRTU-related capital expenditures, the continued funding of nuclear fuel and fuel oil inventory through the ERRA proceeding rather than through rate base, and the adjustment of deferred taxes to reflect the Utility's updated estimate of the impact of 2009 bonus depreciation.

Electric Transmission Owner Rate Cases
On July 28, 2010, the Utility filed an application with the FERC requesting an annual retail transmission revenue requirement of $1.0 billion. The proposed rates represent an increase of $150 million over current authorized revenue requirements. On September 30, 2010, the FERC accepted the Utility's filing and permitted the proposed rates to become effective on March 1, 2011, subject to refund based on a final decision to be issued by the FERC. Hearings in the case have been halted while the Utility and other parties engage in settlement negotiations. Any settlement agreement that the parties may reach will be subject to the FERC's approval. If a settlement is not reached, the FERC will hold hearings and issue a decision after the conclusion of hearings. The Utility will begin collecting the proposed rates on March 1, 2011, and record a reserve for the amount the Utility estimates will be subject to refund.

2011 GAS TRANSMISSION AND STORAGE RATE CASE

In the Utility's 2011 Gas Transmission and Storage rate case, the CPUC will determine the rates and terms and conditions of the Utility's gas transmission and storage services for a four-year period beginning January 1, 2011.

Proposed Settlement Agreement

On August 20, 2010, the Utility and other parties, including TURN and the DRA, requested the CPUC to approve a proposed settlement agreement, known as the Gas Accord V Settlement Agreement ("Gas Accord V"), to set the Utility's gas transmission and storage rates and associated revenue requirements. The CPUC's approval of the proposed Gas Accord V is subject to the resolution of several objections raised by San Diego Gas & Electric Company and Southern California Gas Company regarding their rights and obligations under the proposed agreement. Although the CPUC has not yet issued a final decision on the Gas Accord V, on December 16, 2010, the CPUC issued a final decision that authorized the revenues to be approved in the final decision of the Gas Accord V to be effective as of January 1, 2011.

The Gas Accord V proposes a 2011 natural gas transmission and storage revenue requirement of $514 million, an increase of $52 million over the 2010 adopted revenue requirement. The proposed revenue requirement is $541 million for 2012, $565 million for 2013, and $582 million for 2014. The Gas Accord V proposes average annual capital expenditures of $174 million and average annual depreciation costs of $112 million. The Gas Accord V provides for a 2011 operating and maintenance expense level of $105 million, which would increase at an annual average rate of 2% for 2012 through 2014.

The proposed Gas Accord V maintains a majority of the terms and conditions applicable to the Utility's natural gas transportation and storage services that had been established under previously approved settlement agreements (the first Gas Accord was approved in 1997). Under the proposed Gas Accord V, approximately 45% of the authorized revenue requirements, primarily those costs allocated to core customers, would continue to be assured of recovery through balancing account mechanisms and fixed reservation charges. The Utility's ability to recover the remaining 55% of revenue requirements would continue to depend on throughput volumes and the extent to which non-core customers and other shippers contract for firm transmission services. To reduce the Utility's risk of non-recovery on these remaining revenue requirements, the proposed settlement agreement includes sharing mechanisms. An under-collection or over-collection of the remaining revenue requirements associated with backbone transmission services (35% of the authorized revenue requirement) would be shared equally between the Utility and customers (both core and non-core). Customers would be allocated 75% of any under-collection or over-collection of remaining revenue requirements associated with local transmission services (13% of the authorized revenue requirement). Customers also would be allocated 75% of any over-collection in remaining revenue requirements associated with storage services (7% of the authorized revenue requirement), but the Utility would be at risk for 100% of a net under-collection. The Gas Accord V provides for 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 that are determined in other Utility regulatory proceedings.

Safety Phase

On October 15, 2010, the CPUC added an additional phase to the Utility's 2011 Gas Transmission and Storage Rate Case to address the Utility's natural gas pipeline safety, integrity, and reliability measures and the Utility's emergency response procedures used in its natural gas transmission and storage operations. This new "safety phase" will focus on ensuring the safety and reliability of the Utility's natural gas transmission and storage system. The CPUC will review and consider the types of protocols and procedures that the Utility should have in place or that the CPUC should immediately order to ensure the safe operation of the Utility's gas transmission and storage operations over the next four years. The ruling notes that the new safety phase is distinct from the NTSB's and the CPUC's pending investigations into the cause of the San Bruno accident as well as the CPUC investigation into the Rancho Cordova accident, any proceedings that may be opened as a result of the CPUC's investigation, and any federal or state legislation that may be adopted. The Utility expects that at the CPUC meeting to be held on February 24, 2011, the CPUC will open a new proceeding to address the safe operation of all of the natural gas pipelines in California. (See "Pending Investigations" below.)

Finally, the costs contemplated under the Gas Accord V do not include potential costs associated with the Utility's proposed Pipeline 2020 program of initiatives, announced in October 2010, to work with regulators and industry experts to strengthen the natural gas system over the next decade. The program is expected to focus on the modernization of critical pipeline infrastructure, the use of automatic or remotely operated shut-off valves, the development of industry-leading best practices, and the enhancement of public safety. As part of this program, the Utility plans to create a new non-profit entity to research and develop next-generation pipeline inspection and diagnostic tools. The Utility will provide $10 million to fund this new entity at no cost to customers. The Utility is currently developing the parameters of the proposed Pipeline 2020 program and cost forecasts, and anticipates filing an application with the CPUC to authorize the program in the second quarter of 2011. On December 1, 2010, the Utility requested the CPUC to permit the Utility to establish a memorandum account before the CPUC acts on the Utility's application so the Utility can track costs incurred under the program for possible future recovery through rates. Several protests have been filed to the Utility's request, and the CPUC has not yet acted on the Utility's request. It is possible that some of the work contemplated in the Pipeline 2020 program will be required under legislation that may be enacted in the future or by regulatory order. In that case, the Utility's cost recovery for the mandated activities would be addressed separately by the CPUC.

PG&E Corporation and the Utility anticipate that the CPUC will issue final decisions on the Gas Accord V, the litigated issues, and the safety phase during the first or second quarters of 2011.

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' 2006 through 2008 energy efficiency programs. On December 16, 2010, the CPUC awarded the Utility a final true-up payment award of $29.1 million for the 2006 through 2008 energy efficiency program cycle. Including this award, the Utility has earned incentive revenues totaling $104 million through December 31, 2010 based on the energy savings achieved through implementation of the Utility's energy efficiency programs during the 2006 through 2008 program cycle.

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 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 also confirmed that the risk and reward incentive mechanism would apply to the 2009 program year, subject to various modifications. The CPUC stated that applications for 2009 incentive awards are due by June 30, 2011 to enable the CPUC to issue a final decision by the end of 2011.

On November 15, 2010, a proposed decision was issued that, if adopted by the CPUC, would modify the incentive mechanism that would apply to the 2010 through 2012 program cycle. Among other changes, the proposed modification would limit the total amount of the incentive award or penalty that could be awarded to, or imposed on, all the investor-owned utilities to $189 million. If the proposed decision is adopted, the Utility's opportunity to earn incentive revenues would be limited compared to the mechanism that was in place for the 2006 through 2008 program cycle.

The proposed decision notes that the CPUC may establish a new rule-making proceeding to determine what mechanism, if any, will apply to programs beginning in 2013 and later.

CPUC RESOLUTION REGARDING THE TAX RELIEF ACT

On February 7, 2011, the CPUC staff released a draft resolution that proposes to establish a memorandum account for most cost-of-service rate-regulated utilities. The memorandum account would allow the CPUC to determine whether any future rate reduction is appropriate to reflect the benefits of the Tax Relief Act not otherwise reflected in rates.

The proposed resolution is scheduled to be considered by the CPUC on February 27, 2011. The Utility is unable to predict the outcome of this matter and whether, if the resolution is adopted, it will have a material financial impact on PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows.

DEPLOYMENT OF SMARTMETER™ TECHNOLOGY

The CPUC has authorized the Utility's program to install approximately 10 million advanced electric and gas meters throughout the Utility's service territory by the end of 2012. Advanced electric meters, which record energy usage in hourly or quarter-hourly increments, allow customers to track energy usage throughout the billing month and thus enable greater customer control over electricity costs. Usage data is collected through a wireless communication network and transmitted to the Utility's information system, where the data is stored and used for billing and other Utility business purposes. Advanced electric meters enable the implementation of "dynamic pricing" rates for customers that reflect the higher cost of electricity during periods of high demand. As of December 31, 2010, the Utility has installed 7.5 million meters. The CPUC has authorized the Utility to recover a maximum of $2.3 billion in estimated project costs. Costs that exceed $2.3 billion will not be recoverable through rates. As of December 31, 2010, the Utility has incurred costs of $2.0 billion. The Utility has also recorded a provision of

$36 million, representing the current forecast of capital-related costs that are expected to exceed the CPUC-authorized cost cap and therefore will not be recoverable through rates. The Utility will update its forecasts as the project continues and may incur additional non-recoverable costs.

Following customer complaints that the new metering system led to overcharges, a class action lawsuit was filed against the Utility in state court, both the CPUC and a California Senate Committee began separate investigations, and several municipalities, including the City and County of San Francisco ("CCSF"), took various steps to delay or suspend the installation of the new meters. The class action lawsuit was dismissed by the court because, among other reasons, the court found that the CPUC has exclusive jurisdiction over the issues raised in the complaint. The court has permitted the plaintiff to submit an amended complaint. The California Senate Committee held hearings in April 2010 but did not take any further action before it was disbanded in early November 2010.

In June 2010, the CCSF filed a petition requesting the CPUC to temporarily suspend the installation of additional SmartMeter™ devices until the CPUC completed its investigation. On September 2, 2010, the CPUC released the report of its independent consultant's assessment of the Utility's installation program, which found that the Utility's SmartMeter™ devices and related billing processes perform accurately and as designed. In December 2010, the CPUC dismissed CCSF's petition. The CPUC also dismissed a request to halt installation of the meters that had been made based on concerns about the health, environmental, and safety impacts of the radio frequency ("RF") technology on which the Utility's SmartMeter™ program relies. Several applications for rehearing of this decision were filed. The CPUC has not yet ruled on these applications. The CPUC also has stated that attempts by various municipalities to either suspend or prohibit the installation of SmartMeter™ devices would interfere with the CPUC's exclusive jurisdiction over the Utility's SmartMeter™ program. PG&E Corporation and the Utility are unable to predict the outcome of these matters.

PENDING INVESTIGATIONS

INVESTIGATIONS OF THE SAN BRUNO ACCIDENT

Both the NTSB and the CPUC have begun investigations of the San Bruno accident, but they have not yet determined the cause of the pipeline rupture. The NTSB has issued several public statements regarding the investigation and a metallurgy group report, all of which are available on the NTSB's website. The NTSB will hold fact-finding hearings in Washington, D.C. from March 1, 2011 through March 3, 2011 and has stated that it intends to release a total of six factual reports about the San Bruno accident before the hearings begin based on the following group topics: metallurgy, operations, human performance, survival factors, fire scene, and meteorology. It is expected that these reports will be made publicly available on the NTSB's website as each report is released.

On January 3, 2011, the NTSB issued urgent safety recommendations to the Utility to search for documentation related to its transmission pipeline system components in specified areas that have not had a maximum available operating pressure ("MAOP") established through hydrostatic pressure testing. The NTSB also recommended that the Utility utilize traceable, verifiable, and complete records to determine a valid MAOP, and if the Utility is unable to do so based on appropriate records, then it should determine the MAOP by hydrostatic pressure testing. The CPUC has ordered the Utility to meet the NTSB recommendations by March 15, 2011. On February 1, 2011, the Utility submitted a status report to the CPUC describing the Utility's extensive effort to verify pressure-testing records for over 1,800 miles of gas transmission pipelines covered by the NTSB recommendations. By the March 15, 2011 due date, the Utility expects to determine the covered pipeline segments for which it has complete, verifiable, and traceable records of prior pressure tests. If the Utility is required to perform hydrostatic pressure testing on a substantial portion of its natural gas system, it could incur a material amount of costs.

As part of the CPUC investigation, the CPUC's staff will examine the safety of the Utility's natural gas transmission pipelines in its service territory. The CPUC staff reviewed information about the Utility's planned and unplanned pressurization events where the pressure has risen above the MAOP in several of the Utility's gas transmission lines. On February 2, 2011, the CPUC ordered the Utility to reduce operating pressure twenty percent below the MAOP on certain of its gas transmission pipelines, and also ordered the Utility to reduce operating pressure on other transmission lines that meet certain criteria. The Utility has complied with the CPUC's order and also has reported to the CPUC that the Utility has identified a number of instances where it had either exceeded MAOP by more than ten percent or had raised the pressure to maintain operational flexibility, including several instances in which the highest pressure reading exceeded MAOP by a few pounds, but not more than ten percent above MAOP.

The CPUC also has appointed an independent review panel to gather and review facts, make a technical assessment of the San Bruno accident and its root cause, and make recommendations for action by the CPUC to ensure such an accident is not repeated. The report of the independent review panel is expected in the second quarter of 2011. The recommendations arising from the CPUC's own investigation or the investigation of the independent review panel may include changes to design, construction, operation and maintenance of natural gas facilities; management practices at the Utility in the areas of pipeline integrity and public safety; regulatory and statutory changes; and other recommendations deemed appropriate, including whether there are systemic management problems at the Utility and whether greater resources are needed to achieve fundamental infrastructure improvement.

Several parties have requested that the CPUC institute a formal public investigation of the San Bruno accident. The CPUC may consider this request at its meeting to be held on February 24, 2011. The Utility has filed a response stating that it welcomes the CPUC's investigation. If the CPUC institutes a formal investigation, the CPUC may impose penalties on the Utility if it determines that the Utility violated any laws, rules, regulations, or orders pertaining to the operations and maintenance of its natural gas system. PG&E Corporation and the Utility anticipate that the CPUC will institute one or more formal investigations regarding these matters.

In addition, the Boards of Directors of PG&E Corporation and the Utility appointed a special review committee, composed solely of independent directors, to review the Utility's natural gas transmission and distribution operations. This review will include an assessment of current and emerging industry practices relating to gas transmission and distribution inspection, accident prevention, maintenance, capital and expense planning, engineering, and the Utility's safety practices and culture. The committee has retained an engineering consultant to assist in this review. The review, which commenced in late 2010, is expected to be completed by the third quarter of 2011.

CPUC INVESTIGATION OF THE RANCHO CORDOVA ACCIDENT

On November 19, 2010, the CPUC began a formal investigation of the Rancho Cordova accident. The explosion in a house resulted in one death, injuries to several people, and property damage. The NTSB and the CPUC's Consumer Protection and Safety Division ("CPSD") investigated the accident. The NTSB issued its investigative report in May 2010, and the CPSD submitted its report to the CPUC in November 2010. The NTSB determined that the probable cause of the release, ignition, and explosion of natural gas was the use of a section of unmarked and out-of-specification polyethylene pipe with inadequate wall thickness that allowed gas to leak from the mechanical coupling that had been installed on September 21, 2006. The NTSB stated that the delayed response by the Utility's employees was a contributing factor. Based on the CPSD's and the NTSB's investigative findings, the CPSD requested the CPUC to open a formal investigation of the Rancho Cordova accident and recommended that the CPUC impose unspecified fines and penalties on the Utility. In its order instituting the investigation, the CPUC stated that it will determine whether the Utility violated any law, regulation, CPUC general orders or decisions, or other rules or requirements applicable to its natural gas service and facilities, and/or engaged in unreasonable and/or imprudent practices in connection with the Rancho Cordova accident. The CPUC stated that it intends to ascertain whether any management policies and practices contributed to violations of law and the Rancho Cordova accident. Finally, the CPUC noted that it may order the Utility to implement operational and policy measures designed to prevent future gas safety hazards.

The CPUC ordered the Utility to provide extensive information, from as far back as January 1, 2000, about the Utility's practices and procedures at issue. The Utility's report, due on February 17, 2011, agrees with the NTSB's conclusions about the probable cause of the accident and explains what process improvements the Utility has made to prevent a similar accident in the future. The CPUC has scheduled a pre-hearing conference on March 1, 2011 to establish a schedule for the proceeding, including the date of an evidentiary hearing.

The Utility believes that any remaining third-party liability associated with the Rancho Cordova accident is immaterial. However, PG&E Corporation and the Utility believe that the CPUC is likely to impose penalties on the Utility in connection with the Rancho Cordova accident and that such penalties could be material.

If the CPUC determines that the Utility violated any law, regulation, CPUC general orders or decisions, or other rules or requirements applicable to the Utility's natural gas service and facilities in connection with the San Bruno or Rancho Cordova accidents, the CPUC is authorized to impose penalties of up to $20,000 per day, per violation. In addition, law enforcement authorities could begin proceedings that could result in the imposition of civil or criminal fines or penalties on the Utility. PG&E Corporation and the Utility are unable to predict the ultimate outcome of the investigations discussed above or whether additional investigations will be instituted. Further, the Utility may incur a material amount of additional expenses to comply with CPUC orders issued in connection with its investigations and such costs may not be recoverable through rates. Finally, PG&E Corporation and the Utility may suffer reputational harm which could negatively affect the value of their outstanding securities.

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. 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

Although no comprehensive federal legislation to address climate change has been adopted, the California Legislature adopted the Global Warming Solutions Act of 2006 (also known as Assembly Bill 32 or "AB 32"). AB 32 requires the gradual reduction of GHG emissions in California to the 1990 levels by 2020 on a schedule beginning in 2012. The California Air Resources Board ("CARB") is the state agency charged with setting and monitoring GHG and other emission limits. 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 set pursuant to AB 32. These recommendations include increasing renewable energy supplies, increasing energy efficiency goals, expanding the use of combined heat and power facilities, and developing a multi-sector cap-and-trade program. On September 23, 2010 the CARB implemented one of these recommendations by adopting regulations to require load-serving entities, including the Utility, to gradually increase their deliveries of renewable energy to meet specific annual targets, culminating in a 33% target by 2020. (See discussion of these regulations below under "Renewable Energy Resources.")

The CARB issued proposed cap-and-trade regulations for public comment in October 2010. The proposed regulations include provisions to establish state-wide caps on GHG emissions (for three 3-year compliance periods beginning January 1, 2012 and ending December 31, 2020), allocate allowances (i.e., rights to emit GHGs) among utilities and other industry participants, and permit the purchase and sale of emission allowances through a CARB-managed auction, among other provisions. After considering the comments that had been received, on December 16, 2010, the CARB directed its staff to prepare modified regulations and publish the modified regulations for one or more 15-day public comment and review periods. The modified regulations (with such further modifications as the CARB's executive officer approves) will be submitted to the California Office of Administrative Law for final approval. If the regulations become effective, the first compliance period would begin on January 1, 2012 and apply to the electricity and industrial sectors. The second phase would begin on January 1, 2015 and would expand to include suppliers of natural gas and liquid fossil fuels.

Under the proposed cap-and-trade system, some emission allowances would be allocated to the electric sector utilities at no cost for the benefit of their customers. The investor-owned utilities are required to offer these allowances for sale in the CARB-managed auction. Auction revenues will be used to benefit the utilities' customers. The investor-owned utilities will be required to buy allowances in the CARB auction to meet their own GHG compliance obligations. It is expected that the modified regulations will address, among other issues, the method by which allowances will be allocated to individual utilities, the method for auctioning and distributing allowances to complying entities, the enforcement mechanisms for the program, and whether the proposed allowance price containment reserve will be modified to ensure that reserve allowances are available throughout the program. It is expected that further design and implementation details will be developed over the next several months to address market manipulation concerns and other issues. In July 2011 the Executive Officer will report to the CARB on readiness to implement the cap-and-trade market, and the CARB has stated it has the discretion to delay implementation if it is not prepared to proceed with the market.

Certain implementation and policy issues regarding the proposed AB 32 cap-and-trade program remain subject to resolution by the CPUC, including the approved methods for utilities to procure allowances, offsets, and other instruments under the program, and the rates and methods for utilities to recover compliance costs and use allowance auction revenues for the benefit of their customers. In addition, on January 21, 2011, the San Francisco County Superior Court issued a tentative decision that prohibits the CARB from implementing its cap-and-trade regulations subject to the completion of the required environmental review process.

The ultimate financial impact of the new cap-and-trade system will depend on various factors, including the quantity of allowances that are freely allocated to utilities for customer benefit; the actual market price of emissions allowances over time; the availability of emission offsets; and the extent to which California's cap-and-trade program is linked to other state, regional, or national programs.

RENEWABLE ENERGY RESOURCES

Current California law establishes a Renewable Portfolio Standard ("RPS") that requires California retail sellers of electricity, such as the Utility, to increase their deliveries of renewable energy (such as biomass, hydroelectric facilities with a capacity of 30 MW or less, wind, solar, and geothermal energy) each year, so that the amount of electricity delivered from these 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 retail seller to use future energy deliveries from already-executed contracts to satisfy any shortfalls, provided those deliveries occur within three years of the shortfall. Whether a retail seller who relies on flexible compliance rules has met the RPS target for a particular year may not be known until the end of the associated three-year roll-forward period. The CPUC has indicated that it currently intends to limit its discretion to levy penalties for an unexcused failure to meet an applicable RPS target to a maximum of $25 million per year per retail seller.

On January 13, 2011, the CPUC issued a decision regarding the use of tradable renewable energy credits ("RECs") to comply with the current RPS 20% by 2010 requirements. (A tradable REC refers to a certificate of proof that one megawatt-hour ("MWh") of renewable energy was generated. The certificate can be sold separately from the associated energy.) The CPUC's decision, which modified an earlier decision the CPUC issued in March 2010, imposes on the three largest California investor-owned utilities, including the Utility, a temporary price cap of fifty dollars per tradable REC and a temporary quantity cap that permits the Utility to use tradable RECs for compliance with the RPS target, not to exceed 25% of their annual RPS procurement target in any year. Any tradable REC acquired in excess of this annual limit can be carried over and used for compliance in future years. The provisions imposing the price cap and the limit on the use of tradable RECs will expire on December 31, 2013. For purposes of computing the annual limit, the CPUC decision continues to classify most power-purchase contracts with out-of-state renewable generation facilities as REC-only contracts. Therefore, future deliveries of renewable energy under most of the Utility's power-purchase contracts with out-of-state renewable generation facilities could be included in the computation of the 25% limit.

This limit, combined with the continuing challenges to the development of renewable generation resources within California, negatively affects the Utility's ability to meet the current RPS while the limit remains in effect. Notwithstanding the CPUC's decision, some uncertainty still exists regarding the use of tradable RECs and the ability to satisfy RPS requirements with out-of-state renewable generation, because the CPUC has not yet resolved the utilities' pending joint application for rehearing that was filed with respect to the CPUC's original March 2010 decision.

For the year ended December 31, 2010, the Utility's RPS-eligible renewable resource deliveries equaled 15.9% of its total retail electricity sales. The Utility intends to rely on flexible compliance rules to meet the shortfall in achieving the 2010 RPS target through deliveries of renewable energy over the next three years, the use of tradable RECs within the limit discussed above, or a combination of both. If the developers of renewable energy resources are unable to timely meet their contractual commitments to deliver RPS-eligible energy to the Utility, the Utility believes that the CPUC would consider this fact when determining whether any penalties for non-compliance should be reduced or waived.

In addition to the current RPS law, on September 23, 2010, the CARB adopted regulations that require load-serving entities, including the Utility, to gradually increase their deliveries of renewable energy to meet specific annual targets. For 2012, 2013, and 2014, the amount of electricity delivered from renewable energy resources must equal at least 20% of total energy deliveries, increasing to 24% in 2015, 2016, and 2017, 28% in 2018 and 2019, and 33% in 2020 and beyond. Under this regulation, regulated load-serving entities are allowed to use an unlimited number of tradable RECs. The CARB can impose penalties for failure to meet the targets, but it is unclear how the penalties would be calculated or whether the total penalties are subject to an annual maximum. Although the CARB did not adopt "flexible compliance rules" such as those used by the CPUC to determine compliance with current RPS requirements, the CARB directed its staff to conduct periodic public reviews to assess the effectiveness of the regulations and to recommend to the CARB any necessary modifications. The CARB also has directed its staff to modify the regulations to address concerns about the potential for excessive penalties. It is uncertain when the modified final regulations will be issued.

Finally, legislation has been introduced in the California state legislature that proposes to increase the current RPS from 20% to 33% by 2020. Under the proposed bill, Senate Bill 23, the amount of electricity delivered from renewable energy resources must equal at least 25% of total energy deliveries by December 31, 2016 and 33% by December 31, 2020. The proposed legislation also addresses the use of tradable RECs and contains some "flexible" compliance provisions if a utility is unable to meet the obligations. If enacted, the bill would become effective on January 1, 2012. If enacted, the new law would impose further restrictions on the utilities' ability to satisfy RPS requirements with energy produced from out-of-state renewable generation resources. It remains unclear how this proposed legislation would affect the CARB's regulation on renewable energy deliveries.

WATER QUALITY

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. Although the U.S. Environmental Protection Agency ("EPA") will not issue draft revised regulations before March 2011, on May 4, 2010, the California Water Resources Control Board ("Water Board") adopted a policy on once-through cooling. The policy, effective October 1, 2010, generally requires the installation of cooling towers or other significant measures to reduce the impact on marine life from existing power generation facilities by at least 85%. However, with respect to the state's nuclear power generation facilities, the policy allows other compliance measures to be taken if the costs to install cooling towers are "wholly out of proportion" to the costs considered by the Water Board in developing its policy or if the installation of cooling towers would be "wholly unreasonable" after considering non-cost factors such as engineering and permitting constraints and adverse environmental impacts. The Utility believes that the costs to install cooling towers at Diablo Canyon, which could be as much as $4.5 billion, will meet the "wholly out of proportion" test. The Utility also believes that the installation of cooling towers at Diablo Canyon would be "wholly unreasonable." If the Water Board disagreed and if the installation of cooling towers at Diablo Canyon were not technically or economically feasible, the Utility may be forced to cease operations at Diablo Canyon and may incur a material charge. Assuming the Water Board does not require the installation of cooling towers at Diablo Canyon, the Utility could incur significant costs to comply with alternative compliance measures or to make payments to support various environmental mitigation projects. The Utility would seek to recover such costs in rates. The Utility's Diablo Canyon operations must be in compliance with the Water Board's policy by December 31, 2024.

REMEDIATION

The Utility has been, and may be, required to pay for environmental remediation costs at sites where it is identified as a potentially responsible party under federal and state environmental laws. These sites include former manufactured gas plant ("MGP") sites; current and former power plant sites; former gas gathering and gas storage sites; sites where natural gas compressor stations are located; current and former substations; service center and general construction yard sites; and sites currently and formerly used by the Utility for the storage, recycling, or disposal of hazardous substances. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if it did not deposit those substances on the site. (See Note 15 of the Notes to the Consolidated Financial Statements, for a discussion of estimated environmental remediation liabilities.)

LEGAL MATTERS

In addition to the pending investigations discussed above, various lawsuits, including two class action lawsuits, have been filed by residents of San Bruno in California state courts against PG&E Corporation and the Utility related to the San Bruno accident. (See "Legal Matters" in Note 15 of the Notes to the Consolidated Financial Statements.) The Utility has filed a petition on behalf of PG&E Corporation and the Utility to coordinate these lawsuits in San Mateo County Superior Court. In its statement in support of coordination, the Utility has stated that it is prepared to enter into early mediation in an effort to resolve claims with those plaintiffs willing to do so. A hearing on the Utility's petition is scheduled for February 24, 2011.

The Utility recorded a provision of $220 million in 2010 for estimated third-party claims related to the San Bruno accident, including personal injury and property damage claims, damage to infrastructure, and other damage claims. The Utility currently estimates that it may incur as much as $400 million for third-party claims. This estimate may change depending on the final outcome of the NTSB and CPUC investigations, and the number and nature of third-party claims. As more information becomes known, including information resulting from the NTSB and CPUC investigations, management's estimates and assumptions regarding the amount of third-party liability incurred in connection with the San Bruno accident may change. It is possible that a change in estimate could have a material adverse impact on PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows.

In addition to these lawsuits, a purported shareholder derivative action also has been filed to seek recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims.

PG&E Corporation also received a letter, dated October 4, 2010, on behalf of a purported shareholder, demanding that the PG&E Corporation Board of Directors (1) institute an independent investigation of the San Bruno accident and related alleged safety issues; (2) seek recovery of all costs associated with such issues through legal proceedings against those determined to be responsible, including board members, officers, other employees, and third parties; and (3) adopt corporate governance initiatives and safety programs. The Board of Directors of PG&E Corporation has appointed a committee of independent directors to evaluate this demand and to make a recommendation to the Board on its responses to this demand.

PG&E Corporation and the Utility cannot predict the outcome of these matters.

PG&E Corporation and the Utility also are named as parties in a number of claims and lawsuits that have arisen in the ordinary course of business. In addition, the Utility can incur penalties for failure to comply with federal, state, or local statutes. The accrued liability for legal matters (other than third-party liability claims related to the San Bruno accident as discussed above) totaled $55 million at December 31, 2010 and $57 million at December 31, 2009, and is included in PG&E Corporation's and the Utility's current liabilities – other in the Consolidated Balance Sheets. See "Legal Matters" in Note 15 of the Notes to the Consolidated Financial Statements.

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.

On July 21, 2010, President Obama signed into law new federal financial reform legislation, the Dodd-Frank Wall Street Reform and Consumer Protection Act. PG&E Corporation and the Utility are evaluating the new legislation, and will review future regulations to assess compliance requirements as well as potential impacts on the Utility's procurement activities and risk management programs.

PRICE RISK

The Utility is exposed to commodity price risk as a result of its electricity and natural gas 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 $11 million at December 31, 2010. The Utility's high, low, and average values-at-risk during the 12 months ended December 31, 2010 were approximately $20 million, $10 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, 2010, 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 affect net income for the next 12 months by $6 million, based on net variable rate debt and other interest rate-sensitive instruments outstanding.

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 fails 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, 2010 and 2009:

(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, 2010	**$ 269**	**$ 17**	**$ 252**	**2**	**$ 187**
December 31, 2009	$ 202	$ 24	$ 178	3	$ 154

(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 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. Regulatory assets are amortized over the future periods that 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, the Utility records regulatory liabilities when the CPUC or the FERC requires a refund to be made to customers or has required that a gain or other reduction of net allowable costs be given to customers over future periods.

Determining probability requires significant judgment by 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 2010, 2009, and 2008.

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 that determination was made. At December 31, 2010, PG&E Corporation and the Utility reported regulatory assets (including current regulatory balancing accounts receivable) of $7.6 billion and regulatory liabilities (including current balancing accounts payable) of $4.9 billion.

LOSS CONTINGENCIES

PG&E Corporation and the Utility are subject to various conditions, events, and circumstances with uncertain outcomes. If it is both probable that a liability has been incurred and the amount of the loss can be reasonably estimated, PG&E Corporation and the Utility will record a loss. PG&E Corporation and the Utility evaluate the range of reasonable estimated costs and record a liability based on the lower end of the range, unless an amount within the range is a better estimate than any other amount. These accruals, and the estimates of any additional reasonably possible losses, are reviewed quarterly and are adjusted to reflect the impacts of all information available. As discussed below, PG&E Corporation and the Utility have recorded material accruals for environmental remediation liabilities and for various legal matters.

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 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.

At December 31, 2010 and 2009, the Utility's accruals for undiscounted gross environmental liabilities were $612 million and $586 million, respectively. The Utility's undiscounted future costs could increase to as much as $1.2 billion if the extent of contamination or necessary remediation is greater than anticipated or if the other potentially responsible parties are not financially able to contribute to these costs, and could increase further if the Utility chooses to remediate beyond regulatory requirements. 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.

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, which may result in the recognition of liabilities. PG&E Corporation and the Utility record a provision for a liability when it is both probable and estimable that a liability has been incurred and the amount of the loss can be reasonably estimated. PG&E Corporation and the Utility evaluate the range of reasonably estimated costs and record a liability based on the lower end of the range, unless an amount within the range is a better estimate than any other amount. These accruals, and the estimates of any additional reasonably possible losses, are reviewed quarterly and are adjusted to reflect the impact 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. (See "Legal Matters" in Note 15 of the Notes to the Consolidated Financial Statements.)

ASSET RETIREMENT OBLIGATIONS

PG&E Corporation and the Utility account for an asset retirement obligation ("ARO") at fair value in the period during which the legal obligation is incurred 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.

Most of PG&E Corporation's and the Utility's AROs relate to the Utility's obligation to decommission its nuclear generation facilities and certain fossil-fuel generation facilities. The Utility estimates its obligation for the future decommissioning of its nuclear generation facilities and certain fossil fueled generation facilities. To estimate the liability, the Utility uses a discounted cash flow model based upon significant estimates and assumptions about future decommissioning costs (which are based upon decommissioning costs studies prepared for regulatory purposes), inflation rates, and the estimated date of decommissioning. The estimated future cash flows are discounted using a credit-adjusted risk-free rate that reflects the risk associated with the decommissioning obligation. (See Note 2 of the Notes to the Consolidated Financial Statements.)

Changes in these estimates and assumptions could materially affect the amount of the recorded ARO for these 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 ARO. Additionally, if the inflation adjustment increased 25 basis points, the amount of the ARO would increase by approximately 1.37%. Similarly, an increase in the discount rate by 25 basis points would decrease the amount of the ARO by 1.02%. At December 31, 2010, the Utility's recorded ARO for the estimated cost of retiring these assets is $1.6 billion.

PENSION AND OTHER POSTRETIREMENT PLANS

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"), 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 postretirement benefits"). The measurement of costs and obligations to provide pension benefits and other postretirement benefits are based on a variety of factors, including the provisions of the plans, employee demographics and various actuarial calculations, assumptions, and accounting mechanisms. The assumptions are updated annually and upon any interim re-measurement of the plan obligations.

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 amendments, 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 income 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 $397 million in 2010, $458 million in 2009, and $169 million in 2008. PG&E Corporation and the Utility recorded expense for other postretirement benefits of $104 million in 2010, $94 million in 2009, and $44 million in 2008.

PG&E Corporation and the Utility recognize the funded status of their respective plans on their respective Consolidated Balance Sheets 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. Therefore, the difference is not expected to impact net income in future periods. (See Note 3 of the Notes to the Consolidated Financial Statements.)

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 primarily invested in equity securities and fixed income securities. (See Note 12 of the Notes to the Consolidated Financial Statements.)

PG&E Corporation and the Utility review recent cost trends and projected future trends in establishing health care cost trend rates. This evaluation suggests that current rates of inflation are expected to continue in the near term. In recognition of continued high inflation in health care costs and given the design of PG&E Corporation's plans, the assumed health care cost trend rate for 2010 is 8%, gradually decreasing to the ultimate trend rate of 5% in 2018.

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 6.6% compares to a ten-year actual return of 6.2%.

The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of approximately 600 Aa-grade non-callable bonds at December 31, 2010. 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 benefit 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 2010 Pension Costs	Increase in Projected Benefit Obligation at December 31, 2010
Discount rate	(0.5)%	$ 78	$ 872
Rate of return on plan assets	(0.5)%	46	–
Rate of increase in compensation	0.5%	36	206

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 2010 Other Postretirement Benefit Costs	Increase in Accumulated Benefit Obligation at December 31, 2010
Health care cost trend rate	0.5 %	$ 4	$ 41
Discount rate	(0.5)%	2	103
Rate of return on plan assets	(0.5)%	6	–

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 outstanding debt, the principal at maturity, 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 to 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 principal and interest on its outstanding debt or pay or increase its common stock dividend, meet other obligations, or execute its business strategy.

RISKS RELATED TO PG&E CORPORATION AND THE UTILITY

The ultimate amount of loss the Utility bears in connection with the San Bruno accident could have a material adverse impact on PG&E Corporation's and the Utility's financial condition and results of operations.

PG&E Corporation and the Utility recorded a provision of $220 million in 2010 for estimated third-party claims related to the San Bruno accident, including personal injury and property damage claims, damage to infrastructure, and other damage claims. Various lawsuits have been filed by residents of San Bruno against PG&E Corporation and the Utility seeking to recover compensation for personal injury and property damage and seeking other relief. Both the NTSB and the CPUC are investigating the San Bruno accident, but the cause has not yet been determined. The CPUC has also appointed an independent review panel to gather facts and make a technical assessment of the San Bruno accident and its root cause. The Utility estimates that it may incur as much as $400 million for third-party claims depending on the final outcome of the NTSB and CPUC investigations and the number and nature of third-party claims. Management's estimates and assumptions regarding the financial impact of the San Bruno accident may change as more information becomes known, including information resulting from the investigations by the NTSB and the CPUC.

The Utility maintains liability insurance for damages in the approximate amount of $992 million after a $10 million deductible. PG&E Corporation and the Utility currently consider it likely that most of the costs the Utility incurs for third-party claims relating to the San Bruno accident will ultimately be covered by this insurance. However, PG&E Corporation and the Utility are unable to predict the timing and amount of insurance recoveries.

If the Utility records losses in connection with third-party claims related to the San Bruno accident that materially exceed the amount it has accrued for these liabilities, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially adversely affected in the reporting periods during which additional charges are recorded, depending on whether and when the Utility is able to record or collect insurance recoveries in amounts sufficient to offset such additional accruals during the same reporting periods.

In addition, the Utility currently anticipates that it will incur additional costs associated with its natural gas transmission system, including higher costs for operations, inspection, and maintenance, and costs to perform an exhaustive records search and to perform hydrostatic pressure tests. The Utility also may incur costs, beyond the amount currently anticipated, in response to NTSB or CPUC orders or requests as the investigations continue, or to comply with state or federal legislation that may be enacted that would require the Utility to make various changes to the operations and maintenance of its natural gas transmission system. If the Utility is unable to recover such costs through rates or offset the costs through operational or other cost savings, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially and adversely affected.

Finally, if the CPUC opens a formal investigation related to the San Bruno accident and/or the operations or maintenance of the Utility's natural gas system and determines that the Utility did not comply with applicable statutes, regulations, rules, tariffs, or orders, the CPUC could order the Utility to pay penalties. In addition, law enforcement authorities could begin proceedings that could result in the imposition of civil or criminal fines or penalties on the Utility. If the Utility is required to pay such fines or penalties, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially and adversely affected. PG&E Corporation and the Utility may suffer reputational harm that could negatively affect the value of their outstanding securities.

The Utility could incur fines or penalties in connection with the Rancho Cordova accident.

The CPUC has commenced an investigation into the Rancho Cordova accident, as discussed above. The CPUC will determine whether the Utility violated any law, regulation, CPUC general orders or decisions, or other rules or requirements applicable to its natural gas service and facilities, and/or engaged in unreasonable and/or imprudent practices in connection with the Rancho Cordova accident. The CPUC also stated that it intends to ascertain whether any management policies and practices contributed to violations of law and the Rancho Cordova accident. The CPUC may order the Utility to implement operational and policy measures designed to prevent future gas safety hazards. PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially and adversely affected if the CPUC were to require the Utility to incur costs or other liabilities that are not recoverable through rates or otherwise offset by operating efficiencies or other revenues.

In addition, law enforcement authorities could begin proceedings in connection with the Rancho Cordova accident that could result in the imposition of civil or criminal fines or penalties on the Utility. If the Utility is required to pay such fines or penalties, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially and adversely affected. PG&E Corporation and the Utility may suffer reputational harm that could negatively affect the value of their outstanding securities.

PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows 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 on 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, results of operations, and cash flows.

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 ability to recover its costs may be impacted by 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. For example, during the last economic decline in the Utility's service territory, customer growth slowed and customer demand decreased. Increased unemployment and a decline in the values of residential real estate resulted in an increase in unpaid customer accounts receivable. A sustained downturn or sluggishness in the economy also 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. 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. 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. In addition, reduced forecasted demand for electricity and natural gas as a result of an economic slow-down may also increase the risk that projects are deferred, abandoned, or cancelled.

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 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" above.) If the information on which the estimates and assumptions are based proves 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, results of operations, and cash flows. 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, or if such amounts are not recoverable in rates, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows 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 t hrough 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 (for example, in a general rate case) and actual costs incurred, which, in turn, affect the Utility's ability to earn its authorized rate of return. 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 Utility has entered into a settlement agreement that, if adopted by the CPUC, will set the Utility's revenue requirements for its basic electric and natural gas distribution operations and its electric generation operations through 2013. (See "Regulatory Matters – 2011 General Rate Case Application" above.) It is uncertain whether the settlement agreement will be approved.

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. As customer rates rise to reflect these programs, 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.

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 through 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 of the U.S. Bankruptcy Code. 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. 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 CPUC could disallow some or all of the costs incurred to purchase electricity under such circumstances if the CPUC determined that the Utility acted imprudently or if the CPUC found that the prices or terms of the Utility's purchases of electricity were not reasonable. The Utility's inability to recover its costs could have a material adverse effect on the financial condition, results of operations, or cash flows 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's service territory, or if a greater number of customers became customers of direct access providers or community choice aggregators. California law permits California cities and counties that 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 through municipalization, the exercise of eminent domain power by municipalities to acquire and operate the Utility's facilities, which are then used to provide utility service to the municipality's residents.

In addition, the Utility could lose customers, or experience lesser demand, because of increased customer 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, including non-bypassable charges, 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, financial condition, and cash flows could be negatively impacted.

On April 1, 2009, the California Independent System Operator ("CAISO") implemented MRTU, resulting in a new day-ahead wholesale electricity market becoming effective in California. Other aspects of MRTU are intended to improve electricity grid management reliability, address congestion management, increase operational efficiencies, and improve related technology infrastructure. 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 part of MRTU, the CAISO has created congestion revenue rights ("CRRs") to allow market participants, including load serving entities ("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, 2010, 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 a s 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.

In 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 2012, involves the installation of approximately 10 million advanced electricity and gas meters throughout the Utility's service territory. There have been concerns raised about the accuracy of the meters; privacy; security; customer choice; and the safety, health and environmental aspects of the RF technology used in the system. (See "Regulatory Matters – Deployment of SmartMeter™ Technology" above.) The controversy regarding the new meters may continue, especially when the Utility implements "dynamic pricing" rates for customers as required by the CPUC. Dynamic pricing rates are designed to encourage efficient energy consumption and cost-effective demand response by more closely aligning retail rates with the wholesale electricity market.

The CPUC has authorized the Utility to recover approximately $2.3 billion in estimated project costs. Costs that exceed this amount are not recoverable. At December 31, 2010, the Utility has recorded a provision of $36 million for capital-related costs that are currently forecasted to exceed the authorized amount. If the Utility incurs additional costs that it is unable to recover through rates, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially adversely affected.

If the Utility fails to recognize the expected benefits of its advanced metering infrastructure, 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. Further, the CPUC may disallow costs

incurred by the Utility under power purchase agreements it enters into to meet applicable resource adequacy and renewable energy requirements if the CPUC finds that the costs are unreasonably above-market in the future.
The Utility must achieve an electricity planning reserve margin of 15% to 17% in excess of peak capacity electricity requirements. The Utility must also meet "local" resource adequacy requirements for specific regions in which locally-situated electricity capacity may be needed due to transmission constraints. 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 up to $80 per kW-year. 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.

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. The CPUC also permits the use of a limited amount of tradable RECs to meet RPS requirements. (See "Environmental Matters – Renewable Energy Resources" above.) The CPUC can impose penalties of $50 per 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.

In addition, under its authority to implement AB 32, the CARB adopted regulations on September 23, 2010 that require virtually all load-serving entities, including the Utility, to increase their deliveries of renewable energy to meet specific annual targets. For 2012, 2013, and 2014, the amount of electricity delivered from renewable energy resources must equal at least 20% of total energy deliveries, increasing to 24% in 2015, 2016, and 2017, 28% in 2018 and 2019, and 33% in 2020 and beyond. The CARB can impose penalties for failure to meet the targets but it is unclear how the penalties would be calculated or whether the total penalties are subject to an annual maximum similar to the maximum that the CPUC adopted.

Finally, proposed legislation also has been introduced to the California Legislature that, if adopted, would increase the RPS to 33% by 2020.

Following several request for offers ("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 Utility expects that it will enter into additional agreements in the future. 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 renewable energy requirements depends on timely development of renewable energy facilities. Further, as the market for renewable energy develops, there is a risk that the Utility's contractual commitments could result in procurement costs that are higher than the market price of renewable energy in the future. Although the Utility believes that it will continue to be able to recover the costs it incurs under these agreements in rates as part of the pass-through cost of electricity, there is a risk that the CPUC could disallow such costs in the future to the extent the CPUC considers the Utility's costs to be unreasonably above market.

The Utility faces the risk of unrecoverable costs if its customers obtain distribution and transportation services from other providers a s aresult of municipalization, technological change, or other forms of bypass.
The Utility's customers could bypass its distribution and transportation system by obtaining such services from other providers. 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;
- residential, commercial, and industrial demand;
- the availability of competitively priced alternative energy sources;
- the level of production of natural gas and natural gas supply availability, including inventory (storage);
- the availability of nuclear fuel;
- the availability of non-conventional 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 direct 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 system-wide 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.

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, 2010, there were 12,236 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, including new state cap-and-trade regulations, 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. The Utility may incur significant expense relating to reduction of GHG, compliance with cap-and-trade regulations, 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, AB 32, imposes a statewide limit on the emission of GHG that must be achieved by 2020. The CARB is developing "cap-and-trade" regulations that would establish state-wide annual caps on GHG emissions (from 2012 to 2020), allocate the rights to emit GHGs among utilities, and allow for the purchase and sale of emission allowances through a CARB-managed auction, among other provisions. Depending on the final form of regulations, the Utility could incur significant additional costs to ensure that it complies with the new rules if they become effective as planned on January 1, 2012. 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. 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. These costs may change if federal or regional cap-and-trade programs are adopted.

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. (See "Environmental Matters" above.) The CPUC has established a special ratemaking mechanism under which the Utility is authorized to recover 90% of environmental costs associated with hazardous waste 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 remediation costs associated with the Hinkley natural gas compressor site, or 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, 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 i t m œ 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. In particular, the CPUC may impose penalties on the Utility if the CPUC finds that the Utility violated any law, regulation, CPUC general orders or decisions, or other rules or requirements applicable to its natural gas service and facilities. The CPUC has authority to impose penalties of up to $20,000 per day, per violation. (See "Pending Investigations" above.)

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, 2010	2009	2008
Operating Revenues			
Electric	**$ 10,645**	$ 10,257	$ 10,738
Natural gas	**3,196**	3,142	3,890
Total operating revenues	**13,841**	13,399	14,628
Operating Expenses			
Cost of electricity	**3,898**	3,711	4,425
Cost of natural gas	**1,291**	1,291	2,090
Operating and maintenance	**4,439**	4,346	4,201
Depreciation, amortization, and decommissioning	**1,905**	1,752	1,651
Total operating expenses	**11,533**	11,100	12,367
Operating Income	**2,308**	2,299	2,261
Interest income	**9**	33	94
Interest expense	**(684)**	(705)	(728)
Other income (expense), net	**27**	67	(4)
Income Before Income Taxes	**1,660**	1,694	1,623
Income tax provision	**547**	460	425
Income from Continuing Operations	**1,113**	1,234	1,198
Discontinued Operations			
NEGT income tax benefit	**–**	–	154
Net Income	**1,113**	1,234	1,352
Preferred stock dividend requirement of subsidiary	**14**	14	14
Income Available for Common Shareholders	**$ 1,099**	$ 1,220	$ 1,338
Weighted Average Common Shares Outstanding, Basic	**382**	368	357
Weighted Average Common Shares Outstanding, Diluted	**392**	386	358
Earnings Per Common Share from Continuing Operations, Basic	**$ 2.86**	$ 3.25	$ 3.23
Net Earnings Per Common Share, Basic	**$ 2.86**	$ 3.25	$ 3.64
Earnings Per Common Share from Continuing Operations, Diluted	**$ 2.82**	$ 3.20	$ 3.22
Net Earnings Per Common Share, Diluted	**$ 2.82**	$ 3.20	$ 3.63
Dividends Declared Per Common Share	**$ 1.82**	$ 1.68	$ 1.56

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

PG&E Corporation

(in millions)	Balance at December 31, 2010	2009
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 291**	$ 527
Restricted cash ($38 and $39 related to energy recovery bonds at December 31, 2010 and 2009, respectively)	**563**	633
Accounts receivable		
Customers (net of allowance for doubtful accounts of $81 and $68 at December 31, 2010 and 2009, respectively)	**944**	859
Accrued unbilled revenue	**649**	671
Regulatory balancing accounts	**1,105**	1,109
Other	**794**	750
Regulatory assets	**599**	427
Inventories		
Gas stored underground and fuel oil	**152**	114
Materials and supplies	**205**	200
Income taxes receivable	**47**	127
Other	**193**	240
Total current assets	**5,542**	5,657
Property, Plant, and Equipment		
Electric	**33,508**	30,481
Gas	**11,382**	10,697
Construction work in progress	**1,384**	1,888
Other	**15**	14
Total property, plant, and equipment	**46,289**	43,080
Accumulated depreciation	**(14,840)**	(14,188)
Net property, plant, and equipment	**31,449**	28,892
Other Noncurrent Assets		
Regulatory assets ($735 and $1,124 related to energy recovery bonds at December 31, 2010 and 2009, respectively)	**5,846**	5,522
Nuclear decommissioning trusts	**2,009**	1,899
Income taxes receivable	**565**	596
Other	**614**	379
Total other noncurrent assets	**9,034**	8,396
TOTAL ASSETS	**$ 46,025**	$ 42,945

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

PG&E Corporation

(in millions, except share amounts)	Balance at December 31, 2010	2009
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term borrowings	**$ 853**	$ 833
Long-term debt, classified as current	**809**	342
Energy recovery bonds, classified as current	**404**	386
Accounts payable		
Trade creditors	**1,129**	984
Disputed claims and customer refunds	**745**	773
Regulatory balancing accounts	**256**	281
Other	**379**	349
Interest payable	**862**	818
Income taxes payable	**77**	214
Deferred income taxes	**113**	332
Other	**1,558**	1,501
Total current liabilities	**7,185**	6,813
Noncurrent Liabilities		
Long-term debt	**10,906**	10,381
Energy recovery bonds	**423**	827
Regulatory liabilities	**4,525**	4,125
Pension and other postretirement benefits	**2,234**	1,773
Asset retirement obligations	**1,586**	1,593
Deferred income taxes	**5,547**	4,732
Other	**2,085**	2,116
Total noncurrent liabilities	**27,306**	25,547
Commitments and Contingencies (Note 15)		
Equity		
Shareholders' Equity		
Preferred stock	**–**	–
Common stock, no par value, authorized 800,000,000 shares, 395,227,205 shares outstanding at December 31, 2010 and 371,272,457 shares outstanding at December 31, 2009	**6,878**	6,280
Reinvested earnings	**4,606**	4,213
Accumulated other comprehensive loss	**(202)**	(160)
Total shareholders' equity	**11,282**	10,333
Noncontrolling Interest – Preferred Stock of Subsidiary	**252**	252
Total equity	**11,534**	10,585
TOTAL LIABILITIES AND EQUITY	**$ 46,025**	$ 42,945

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

PG&E Corporation

(in millions)	Year ended December 31, 2010	2009	2008
Cash Flows from Operating Activities			
Net income	**$ 1,113**	$ 1,234	$ 1,352
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	**2,151**	1,947	1,863
Allowance for equity funds used during construction	**(110)**	(94)	(70)
Deferred income taxes and tax credits, net	**756**	809	590
Other	**47**	(26)	(6)
Effect of changes in operating assets and liabilities:			
Accounts receivable	(44)	156	(87)
Inventories	(43)	109	(59)
Accounts payable	48	(40)	(140)
Disputed claims and customer refunds	–	(700)	–
Income taxes receivable/payable	(78)	171	(59)
Other current assets	(9)	122	(185)
Other current liabilities	120	172	90
Regulatory assets, liabilities, and balancing accounts, net	(394)	(516)	(374)
Other changes in noncurrent assets and liabilities	**(351)**	(305)	(152)
Net cash provided by operating activities	**3,206**	3,039	2,763
Cash Flows from Investing Activities			
Capital expenditures	**(3,802)**	(3,958)	(3,628)
Decrease in restricted cash	**66**	666	36
Proceeds from sales and maturities of nuclear decommissioning trust investments	**1,405**	1,351	1,635
Purchases of nuclear decommissioning trust investments	**(1,456)**	(1,414)	(1,684)
Other	**(70)**	19	(11)
Net cash used in investing activities	**(3,857)**	(3,336)	(3,652)
Cash Flows from Financing Activities			
Borrowings under revolving credit facilities	**490**	300	533
Repayments under revolving credit facilities	**(490)**	(300)	(783)
Net issuances of commercial paper, net of discount of $3 in 2010 and 2009, and $11 in 2008	**267**	43	6
Proceeds from issuance of short-term debt, net of issuance costs of $1 in 2010 and 2009	**249**	499	–
Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $23 in 2010, $29 in 2009, and $19 in 2008	**1,327**	1,730	2,185
Short-term debt matured	**(500)**	–	–
Long-term debt matured or repurchased	**(95)**	(909)	(454)
Energy recovery bonds matured	**(386)**	(370)	(354)
Common stock issued	**303**	219	225
Common stock dividends paid	**(662)**	(590)	(546)
Other	**(88)**	(17)	(49)
Net cash provided by financing activities	**415**	605	763
Net change in cash and cash equivalents	**(236)**	308	(126)
Cash and cash equivalents at January 1	**527**	219	345
Cash and cash equivalents at December 31	**$ 291**	$ 527	$ 219
Supplemental disclosures of cash flow information			
Cash received (paid) for:			
Interest, net of amounts capitalized	**$ (627)**	$ (612)	$ (523)
Income taxes, net	**(135)**	359	112
Supplemental disclosures of noncash investing and financing activities			
Common stock dividends declared but not yet paid	**$ 183**	$ 157	$ 143
Capital expenditures financed through accounts payable	**364**	273	348
Noncash common stock issuances	**265**	50	22

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	Noncontrolling Interest – Preferred Stock of Subsidiary	Total Equity	Compre-hensive Income
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)	–	–	–	–	(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)	–	–	–	–	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	
Net income	–	–	–	1,113	–	1,113	–	1,113	$ 1,113
Employee benefit plan adjustment (net of income tax benefit of $25)	–	–	–	–	(42)	(42)	–	(42)	(42)
Comprehensive income									$ 1,071
Common stock issued, net	23,954,748	568	–	–	–	568	–	568	
Stock-based compensation amortization	–	34	–	–	–	34	–	34	
Common stock dividends declared	–	–	–	(706)	–	(706)	–	(706)	
Tax expense from employee stock plans	–	(4)	–	–	–	(4)	–	(4)	
Preferred stock dividend requirement of subsidiary	–	–	–	(14)	–	(14)	–	(14)	
Balance at December 31, 2010	**395,227,205**	**$ 6,878**	**$ –**	**$ 4,606**	**$ (202)**	**$ 11,282**	**$ 252**	**$ 11,534**	

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF INCOME

Pacific Gas and Electric Company

	Year ended December 31,		
(in millions)	**2010**	2009	2008
Operating Revenues			
Electric	**$ 10,644**	$ 10,257	$ 10,738
Natural gas	**3,196**	3,142	3,890
Total operating revenues	**13,840**	13,399	14,628
Operating Expenses			
Cost of electricity	**3,898**	3,711	4,425
Cost of natural gas	**1,291**	1,291	2,090
Operating and maintenance	**4,432**	4,343	4,197
Depreciation, amortization, and decommissioning	**1,905**	1,752	1,650
Total operating expenses	**11,526**	11,097	12,362
Operating Income	**2,314**	2,302	2,266
Interest income	**9**	33	91
Interest expense	**(650)**	(662)	(698)
Other income, net	**22**	59	28
Income Before Income Taxes	**1,695**	1,732	1,687
Income tax provision	**574**	482	488
Net Income	**1,121**	1,250	1,199
Preferred stock dividend requirement	**14**	14	14
Income Available for Common Stock	**$ 1,107**	$ 1,236	$ 1,185

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

Pacific Gas and Electric Company

(in millions)	Balance at December 31, 2010	2009
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 51**	$ 334
Restricted cash ($38 and $39 related to energy recovery bonds at December 31, 2010 and 2009, respectively)	**563**	633
Accounts receivable		
Customers (net of allowance for doubtful accounts of $81 at and $68 at December 31, 2010 and 2009, respectively)	**944**	859
Accrued unbilled revenue	**649**	671
Regulatory balancing accounts	**1,105**	1,109
Other	**856**	751
Regulatory assets	**599**	427
Inventories		
Gas stored underground and fuel oil	**152**	114
Materials and supplies	205	200
Income taxes receivable	**48**	138
Other	**190**	235
Total current assets	**5,362**	5,471
Property, Plant, and Equipment		
Electric	**33,508**	30,481
Gas	**11,382**	10,697
Construction work in progress	**1,384**	1,888
Total property, plant, and equipment	**46,274**	43,066
Accumulated depreciation	**(14,826)**	(14,175)
Net property, plant, and equipment	**31,448**	28,891
Other Noncurrent Assets		
Regulatory assets ($735 and $1,124 related to energy recovery bonds at December 31, 2010 and 2009, respectively)	**5,846**	5,522
Nuclear decommissioning trusts	**2,009**	1,899
Income taxes receivable	**614**	610
Other	**400**	316
Total other noncurrent assets	**8,869**	8,347
TOTAL ASSETS	**$ 45,679**	$ 42,709

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, 2010	2009
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	**$ 853**	$ 833
Long-term debt, classified as current	**809**	95
Energy recovery bonds, classified as current	**404**	386
Accounts payable		
Trade creditors	**1,129**	984
Disputed claims and customer refunds	**745**	773
Regulatory balancing accounts	**256**	281
Other	**390**	363
Interest payable	**857**	813
Income taxes payable	**116**	223
Deferred income taxes	**118**	334
Other	**1,349**	1,307
Total current liabilities	**7,026**	6,392
Noncurrent Liabilities		
Long-term debt	**10,557**	10,033
Energy recovery bonds	**423**	827
Regulatory liabilities	**4,525**	4,125
Pension and other postretirement benefits	**2,174**	1,717
Asset retirement obligations	**1,586**	1,593
Deferred income taxes	**5,659**	4,764
Other	**2,008**	2,073
Total noncurrent liabilities	**26,932**	25,132
Commitments and Contingencies (Note 15)		
Shareholders' Equity		
Preferred stock	**258**	258
Common stock, $5 par value, authorized 800,000,000 shares, 264,374,809 shares outstanding at December 31, 2010 and 2009	**1,322**	1,322
Additional paid-in capital	**3,241**	3,055
Reinvested earnings	**7,095**	6,704
Accumulated other comprehensive loss	**(195)**	(154)
Total shareholders' equity	**11,721**	11,185
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**$ 45,679**	$ 42,709

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Pacific Gas and Electric Company

(in millions)	Year ended December 31, 2010	2009	2008
Cash Flows from Operating Activities			
Net income	**$ 1,121**	$ 1,250	$ 1,199
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	**2,116**	1,927	1,838
Allowance for equity funds used during construction	**(110)**	(94)	(70)
Deferred income taxes and tax credits, net	**762**	787	593
Other	**46**	(27)	(6)
Effect of changes in operating assets and liabilities:			
Accounts receivable	(105)	157	(83)
Inventories	(43)	109	(59)
Accounts payable	109	(33)	(137)
Disputed claims and customer refunds	–	(700)	–
Income taxes receivable/payable	(58)	21	43
Other current assets	(7)	122	(187)
Other current liabilities	130	183	60
Regulatory assets, liabilities, and balancing accounts, net	(394)	(516)	(374)
Other changes in noncurrent assets and liabilities	**(331)**	(282)	(51)
Net cash provided by operating activities	**3,236**	2,904	2,766
Cash Flows from Investing Activities			
Capital expenditures	**(3,802)**	(3,958)	(3,628)
Decrease in restricted cash	**66**	666	36
Proceeds from sales and maturities of nuclear decommissioning trust investments	**1,405**	1,351	1,635
Purchases of nuclear decommissioning trust investments	**(1,456)**	(1,414)	(1,684)
Other	**19**	11	1
Net cash used in investing activities	**(3,768)**	(3,344)	(3,640)
Cash Flows from Financing Activities			
Borrowings under revolving credit facilities	**400**	300	533
Repayments under revolving credit facilities	**(400)**	(300)	(783)
Net issuances of commercial paper, net of discount of $3 in 2010 and 2009, and $11 in 2008	**267**	43	6
Proceeds from issuance of short-term debt, net of issuance costs of $1 in 2010 and 2009	**249**	499	–
Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $23 in 2010, $25 in 2009, and $19 in 2008	**1,327**	1,384	2,185
Short-term debt matured	**(500)**	–	–
Long-term debt matured or repurchased	**(95)**	(909)	(454)
Energy recovery bonds matured	**(386)**	(370)	(354)
Preferred stock dividends paid	**(14)**	(14)	(14)
Common stock dividends paid	**(716)**	(624)	(568)
Equity contribution	**190**	718	270
Other	**(73)**	(5)	(36)
Net cash provided by financing activities	**249**	722	785
Net change in cash and cash equivalents	**(283)**	282	(89)
Cash and cash equivalents at January 1	**334**	52	141
Cash and cash equivalents at December 31	**$ 51**	$ 334	$ 52
Supplemental disclosures of cash flow information			
Cash received (paid) for:			
Interest, net of amounts capitalized	**$ (595)**	$ (578)	$ (496)
Income taxes, net	**(171)**	170	95
Supplemental disclosures of noncash investing and financing activities			
Capital expenditures financed through accounts payable	**$ 364**	$ 273	$ 348

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

Pacific Gas and Electric Company

(in millions)	Preferred Stock	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, 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 $159)	–	–	–	–	–	(229)	(229)	(229)
Comprehensive income								**$ 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 $10)	–	–	–	–	–	62	62	62
Comprehensive income								**$ 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**	
Net income	–	–	–	–	1,121	–	1,121	$ 1,121
Employee benefit plan adjustment (net of income tax benefit of $25)	–	–	–	–	–	(41)	(41)	(41)
Comprehensive income								**$ 1,080**
Equity contribution	–	–	190	–	–	–	190	
Tax expense from employee stock plans	–	–	(4)	–	–	–	(4)	
Common stock dividend	–	–	–	–	(716)	–	(716)	
Preferred stock dividend	–	–	–	–	(14)	–	(14)	
Balance at December 31, 2010	**$ 258**	**$ 1,322**	**$ 3,241**	**$ –**	**$ 7,095**	**$ (195)**	**$ 11,721**	

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 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. 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. All intercompany transactions have been eliminated from the Consolidated Financial Statements.

The accompanying Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") for annual financial statements and in accordance with the instructions to Form 10-K and Regulation S-X promulgated by the Securities and Exchange Commission ("SEC"). The preparation of financial statements in conformity with 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 relate to the Utility's regulatory assets and liabilities, environmental remediation liabilities, asset retirement obligations ("ARO"), and pension plan and other postretirement plan obligations. In addition, management has made significant estimates and assumptions for accruals related to the rupture of a natural gas transmission pipeline owned and operated by the Utility in the City of San Bruno, California, on September 9, 2010, as well as accruals for various legal matters. (See Note 15 below.) Management believes that its estimates and assumptions reflected in the Consolidated Financial Statements are appropriate and reasonable. Actual results could differ materially from those estimates.

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

CASH AND CASH EQUIVALENTS

Cash equivalents consist of short-term, highly liquid investments with original maturities of three months or less. Cash equivalents are stated at cost, which approximates fair value. PG&E Corporation and the Utility invest their cash primarily 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 13 below.) 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, aging of receivables, current economic conditions, and assessment of customer collectability.

INVENTORIES

Inventories are carried at weighted average cost and are valued at the lower of weighted-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, 2010 are as follows:

(in millions)	Gross Plant as of December 31, 2010	Accumulated Depreciation as of December 31, 2010	Net Plant as of December 31, 2010
Electricity generating facilities [(1)]	**$ 6,012**	**$ (1,404)**	**$ 4,608**
Electricity distribution facilities	**20,991**	**(7,161)**	**13,830**
Electricity transmission	**6,505**	**(1,829)**	**4,676**
Natural gas distribution facilities	**7,443**	**(2,819)**	**4,624**
Natural gas transportation and storage	**3,939**	**(1,613)**	**2,326**
Construction work in progress	**1,384**	**—**	**1,384**
Total	**$ 46,274**	**$ (14,826)**	**$ 31,448**

(1) Balance includes nuclear fuel inventories. Stored nuclear fuel inventory is stated at weighted average cost. Nuclear fuel in the reactor is expensed as it is used based on the amount of energy output. (See Note 15 below.)

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 [(1)]	$ 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 and storage	3,628	(1,554)	2,074
Construction work in progress	1,888	–	1,888
Total	$ 43,066	$ (14,175)	$ 28,891

(1) Balance includes nuclear fuel inventories. Stored nuclear fuel inventory is stated at weighted average cost. Nuclear fuel in the reactor is expensed as it is used based on the amount of energy output. (See Note 15 below.)

AFUDC

AFUDC is a method used to compensate the Utility for the estimated cost of debt (interest) and equity funds used to finance regulated plant additions, and is capitalized as part of the cost of construction projects. AFUDC is recoverable from customers through rates over the life of the related property once the property is placed in service. The portion of AFUDC related to the cost of debt is recorded as a reduction to interest expense. AFUDC related to the cost of equity is recorded in other income. The Utility recorded AFUDC of $110 million and $50 million during 2010, $95 million and $44 million during 2009, $70 million and $44 million during 2008, 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 3.38% in 2010, 3.43% in 2009, and 3.38% in 2008.

	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 and 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 the depreciation expense is recovered through rates charged to customers. Depreciation expense includes a component for the original cost of assets and a component for estimated cost of future removal, net of any salvage value at retirement. Upon retirement, the original cost of the retired assets, net of salvage value, is charged to accumulated depreciation. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is charged to operating and maintenance expense as incurred.

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. Capitalized software costs totaled $580 million at December 31, 2010 and $562 million at December 31, 2009, net of accumulated amortization of

$386 million at December 31, 2010 and $315 million at December 31, 2009. Amortization expense for capitalized software was $94 million in 2010, $37 million in 2009, and $73 million in 2008. Amortization expense is estimated to be approximately $120 million annually for 2011 through 2015.

REGULATION AND REGULATED OPERATIONS

As a regulated entity, the Utility's rates are designed to recover the costs 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. Regulatory assets are amortized over the future periods that the costs are 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.

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 refunded to customers are recorded as regulatory balancing account liabilities. For further discussion please see "Revenue Recognition" below.

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 with lives ranging from 19 to 40 years. The gross carrying amount of the hydroelectric facility licenses and other agreements was $112 million at December 31, 2010 and $110 million at December 31, 2009. The accumulated amortization was $44 million at December 31, 2010 and $40 million at December 31, 2009.

The Utility's amortization expense related to intangible assets was $4 million in 2010, 2009, and 2008. The estimated annual amortization expense for 2011 through 2015 based on the December 31, 2010 intangible assets balance is $3 million. Intangible assets are recorded to other noncurrent assets – other in the Consolidated Balance Sheets.

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. 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. Estimated cash flows were revised as a result of the studies completed in the first quarter of 2009.

For GAAP purposes, the Utility adjusts its nuclear decommissioning obligation to reflect changes in the estimate of decommissioning its nuclear power facilities and records this as an adjustment to ARO on its Consolidated Balance Sheets. The total nuclear decommissioning obligation accrued in accordance with GAAP was $1.2 billion at December 31, 2010 and $1.4 billion at December 31, 2009. For regulatory purposes, the estimated undiscounted nuclear decommissioning cost for the Utility's nuclear power plants was approximately $2.3 billion at December 31, 2010 and 2009 (or approximately $4.4 billion and $4.6 billion in future dollars, respectively). These estimates are based on the 2009 decommissioning cost studies, prepared in accordance with CPUC requirements.

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 below.)

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

(in millions)	
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
Revision in estimated cash flows	(23)
Accretion	93
Liabilities settled	(77)
ARO liability at December 31, 2010	**$ 1,586**

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 therefore, 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 the operation of a facility becomes uneconomical. The operation of the majority of the Utility's hydroelectric facilities is currently, and for the foreseeable future, economically beneficial. Therefore, 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 2010, 2009, or 2008.

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. PG&E Corporation and the Utility recorded unamortized loss on debt extinguishments, net of gain, of $204 million and $227 million at December 31, 2010 and 2009, respectively. The amortization expense related to this loss was $23 million in 2010, $25 million in 2009, and $26 million in 2008. Deferred gains and losses on debt extinguishments are recorded to 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)		
(in millions)	**2010**	2009	2008
Balance at beginning of year	**$ (160)**	$ (221)	$ 10
Period change in pension benefits and other benefits:			
Unrecognized prior service cost [1]	**(29)**	(1)	37
Unrecognized net gain (loss) [2]	**(110)**	363	(1,583)
Unrecognized net transition obligation [3]	**15**	15	15
Transfer to regulatory account [4][5]	**82**	(316)	1,300
Balance at end of year	**$ (202)**	$ (160)	$ (221)

(1) Net of income tax benefit (expense) of $20 million, $1 million, and $(27) million for December 31, 2010, 2009, and 2008, respectively.
(2) Net of income tax benefit (expense) of $73 million, $(216) million, and $1,088 million for December 31, 2010, 2009, and 2008, respectively.
(3) Net of income tax benefit (expense) of $(11) million for December 31, 2010, 2009, and 2008.
(4) Net of income tax benefit (expense) of $(57) million, $218 million, and $(894) million for December 31, 2010, 2009, and 2008, respectively.
(5) Amounts transferred to the pension regulatory asset are probable of 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 services are delivered, and include amounts for services rendered but not yet billed at the end of the period.

The Utility recognizes 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 below.)

The CPUC authorizes most of the Utility's revenue requirements in its general rate case ("GRC"), which generally occurs 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 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 revenue recognition criteria for pass-through costs billed to customers 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 15 below.)

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 and unbilled.

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 deferred and amortized to income over time. The Utility amortizes its investment tax credits over the life of the related property in accordance with regulatory treatment. PG&E Corporation amortizes its investment tax credits over the projected investment recovery period or the life of the arrangement for its tax equity arrangements. (See Note 9 below.)

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.

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'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's nuclear decommissioning costs are recovered from customers through rates.

The Utility classifies its investments held in the nuclear decommissioning trust as "available-for-sale." As the Utility's nuclear decommissioning trust assets are managed by external investment managers, the Utility does not have the ability to sell its investments at their discretion. 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.

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 net income 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 below.)

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). (See Note 11 below.)

ADOPTION OF NEW ACCOUNTING PRONOUNCEMENTS

Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities

On January 1, 2010, PG&E Corporation and the Utility adopted an accounting standards update that changes when and how to determine, or re-determine, whether an entity is a variable interest entity ("VIE"), which could require consolidation. In addition, the accounting standards update replaces the quantitative approach for determining who has a controlling financial interest in a VIE with a qualitative approach and requires ongoing assessments of whether an entity is the primary beneficiary of a VIE. The adoption of the accounting standards update did not have a material impact on PG&E Corporation's or the Utility's Consolidated Financial Statements.

PG&E Corporation and the Utility are required to consolidate any entities that they control. In most cases, control can be determined based on majority ownership or voting interests. However, for certain entities, control is difficult to discern based on ownership or voting interests alone. These entities are referred to as VIEs. A VIE is an entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support from other parties, or whose equity investors lack any characteristics of a controlling financial interest. An enterprise has a controlling financial interest if it has the obligation to absorb expected losses or receive expected gains that could potentially be significant to a VIE and the power to direct the activities that are most significant to a VIE's economic performance. An enterprise that has a controlling financial interest is known as the VIE's primary beneficiary and is required to consolidate the VIE.

Some of the counterparties to the Utility's power purchase agreements are considered VIEs. In determining whether the Utility has a controlling financial interest in a VIE, the Utility must first assess whether it absorbs any of the VIE's expected losses or receives any portion of the VIE's expected residual returns, as a result of power purchase agreements. This assessment includes an evaluation of how the risks and rewards associated with the power plant's activities are absorbed by variable interest holders. These VIEs are typically exposed to credit risk, production risk, commodity price risk, and any applicable tax incentive risks, among others. The Utility analyzes the variability in the VIE's gross margin and the impact of power purchase agreements on the gross margin to determine whether the Utility absorbs variability, resulting in a variable interest. Factors that may be considered when assessing the impact of a power purchase agreement on the VIE's gross margin include the pricing structure of the power purchase agreement and the cost of inputs and production, which depend on the technology of the power plant.

For each variable interest, the Utility must also assess whether it has the power to direct the activities of the power plant that most directly impact the VIE's economic performance. This assessment considers any decision-making rights associated with designing the VIE, any dispatch rights, any operating and maintenance activities, and any re-marketing activities of the power plant after the end of the power purchase agreement with the Utility.

The Utility held a variable interest in several entities that own power plants that generate electricity for sale to the Utility under power purchase agreements. Each of these VIEs was designed to own a power plant that would generate electricity for sale to the Utility utilizing various technologies such as natural gas, wind, solar photovoltaic, solar thermal, and hydroelectric. Under each of these power purchase agreements, the Utility is obligated to purchase electricity or capacity, or both, from the VIE. The Utility did not provide any other support to these VIEs, and the Utility's financial exposure is limited to the amount it pays for delivered electricity and capacity. (See Note 15 below.) The Utility does not have the power to direct the activities that are most significant to these VIE's economic performance. As a result, the Utility does not have a controlling financial interest in any of these VIEs. Therefore, at December 31, 2010, the Utility was not the primary beneficiary of, and did not consolidate, any of these VIEs.

The Utility continued to consolidate PG&E Energy Recovery Funding LLC ("PERF") at December 31, 2010, as the Utility is the primary beneficiary of PERF. The Utility has a controlling financial interest in PERF since the Utility is exposed to PERF's losses and returns through the Utility's 100% equity investment in PERF, and the Utility was involved in the design of PERF, which was an activity that was significant to PERF's economic performance. The assets of PERF were $897 million at December 31, 2010 and primarily consisted of assets related to energy recovery bonds ("ERBs"), which are included in other noncurrent assets – regulatory assets in the Consolidated Balance Sheets. The liabilities of PERF were $827 million at December 31, 2010 and consisted of energy recovery bonds, which are included in current and noncurrent liabilities in the Consolidated Balance Sheets. (See Note 5 below.) The assets of PERF are only available to settle the liabilities of PERF.

As of December 31, 2010, PG&E Corporation's affiliates had entered into four tax equity agreements with privately held companies to fund residential and commercial retail solar energy installations. Under these agreements, PG&E Corporation will provide payments of up to $300 million to these companies, and in return, receive the benefits from local rebates, federal investment tax credits or grants, and a share of these companies' customer payments. PG&E Corporation could be required to pay up to an additional $41 million in the event that its ownership interests are liquidated when in a deficit position. However, PG&E Corporation's financial exposure from these agreements is generally limited to its lease payments and investment contributions to these companies. As of December 31, 2010, PG&E Corporation had made total payments of $149 million under these agreements, primarily related to its lease payments and investment contributions to these companies. These amounts are recorded in other noncurrent assets – other in PG&E Corporation's Consolidated Balance Sheet. PG&E Corporation holds a variable interest in these companies as a result of these agreements. When determining whether PG&E Corporation is the primary beneficiary of these companies, it evaluated which party has control over their significant economic activities, such as designing the companies, vendor selection, construction, customer selection, and re-marketing activities at the end of customer leases. As these activities are under the control of these companies, PG&E Corporation was not the primary beneficiary of, and did not consolidate, any of these companies at December 31, 2010.

NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

REGULATORY ASSETS

Current Regulatory Assets

At December 31, 2010 and 2009, the Utility had current regulatory assets of $599 million and $427 million, respectively, consisting primarily of price risk management regulatory assets. The current portion of price risk management regulatory assets represents the deferral of unrealized losses related to price risk management derivative instruments with terms of one year or less. (See Note 10 below.)

Long-Term Regulatory Assets

Long-term regulatory assets are composed of the following:

	Balance at December 31,	
(in millions)	**2010**	2009
Pension benefits	**$ 1,759**	$ 1,386
Deferred income taxes	**1,250**	1,027
Energy recovery bonds	**735**	1,124
Utility retained generation	**666**	737
Environmental compliance costs	**450**	408
Price risk management	**424**	346
Unamortized loss, net of gain, on reacquired debt	**181**	203
Other	**381**	291
Total long-term regulatory assets	**$ 5,846**	$ 5,522

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 12 below.)

The regulatory assets for deferred income taxes represent deferred income tax benefits previously passed through to customers. The CPUC requires the Utility to pass through certain tax benefits to customers by reducing rates, thereby ignoring the effect of deferred taxes on rates. Based on current regulatory ratemaking and income tax laws, the Utility expects to recover these regulatory assets over average plant depreciation lives of 1 to 45 years.

The regulatory asset for ERBs 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 of the U.S. Bankruptcy Code

("Chapter 11 Settlement Agreement"). (See Note 5 below.) The regulatory asset is amortized over the life of the bonds, consistent with the period over which the related revenues and bond-related expenses are recognized. The Utility expects to fully recover this asset by the end of 2012 when the ERBs mature.

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 being 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 13 years.

The regulatory assets for environmental compliance costs represent the portion of estimated environmental remediation costs 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 32 years. (See Note 15 below.)

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. (See Note 10 below.)

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 next 16 years, which is the remaining amortization period of the reacquired debt. The Utility expects to fully recover these costs by 2026.

At December 31, 2010 and 2009, "other" primarily consisted of regulatory assets relating to ARO expenses for decommissioning of the Utility's fossil-fuel generation facilities that are probable of future recovery through the ratemaking process; costs that the Utility incurred in terminating a 30-year power purchase agreement, which are being amortized and collected in rates through September 2014; and costs incurred in relation to the Utility's plan of reorganization under Chapter 11, which became effective in April 2004. Additionally, at December 31, 2010, "other" included removal costs associated with the replacement of old electromechanical meters with SmartMeter™ devices.

In general, the Utility does not earn a return on regulatory assets if the related costs do not accrue interest. Accordingly, the Utility earns a return only on its retained generation regulatory assets and regulatory assets for unamortized loss, net of gain, on reacquired debt.

REGULATORY LIABILITIES

Current Regulatory Liabilities

At December 31, 2010 and 2009, the Utility had current regulatory liabilities of $81 million and $163 million, respectively, primarily consisting of amounts that the Utility expects to refund to customers for over-collected electric transmission rates and amounts that the Utility expects to refund to electric transmission customers for their portion of settlements the Utility entered into with various electricity suppliers to resolve certain remaining Chapter 11 disputed claims. 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)	**2010**	2009
Cost of removal obligation	**$ 3,229**	$ 2,933
Recoveries in excess of ARO	**600**	488
Public purpose programs	**573**	508
Other	**123**	196
Total long-term regulatory liabilities	**$ 4,525**	$ 4,125

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 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.

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. The public purpose programs regulatory liabilities primarily consist of revenues collected from customers to pay for costs that the Utility expects to incur in the future under energy efficiency programs designed to encourage the manufacture, design, distribution, and customer use of energy efficient appliances and other energy-using products; under the California Solar Initiative program to promote the use of solar energy in residential homes and commercial, industrial, and agricultural properties; and under the Self-Generation Incentive program to promote distributed generation technologies installed on the customer's side of the Utility meter that provide electricity and gas for all or a portion of that customer's load.

"Other" at December 31, 2010 and 2009 primarily consisted of regulatory liabilities related to 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 into with Mirant Corporation and insurance recoveries for hazardous substance remediation.

REGULATORY BALANCING ACCOUNTS

The Utility's current regulatory balancing accounts represent the amounts expected to be received from or refunded to 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)	**2010**	2009
Utility generation	**$ 303**	$ 355
Public purpose programs	**164**	83
Distribution revenue adjustment mechanism	**145**	152
Gas fixed cost	**56**	93
Hazardous substance	**38**	30
Other	**143**	115
Total regulatory balancing accounts, net	**$ 849**	$ 828

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 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'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, there is generally an over-collection due to higher rates and electric usage that cause an increase in generation billings.

The public purpose programs balancing accounts primarily track the recovery of the authorized public purpose program revenue requirements and incentive awards earned by the Utility for implementing customer energy efficiency 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.

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-collected or over-collected position of this account is dependent on seasonality and volatility in gas volumes.

The hazardous substance balancing accounts are used to track recoverable hazardous substance cleanup costs through the CPUC-approved ratemaking mechanism that authorizes the Utility to recover 90% of hazardous waste remediation costs. The current balance represents eligible remediation costs incurred by the Utility during 2009 that will be recovered through an annual true-up filing with the CPUC in January 2011. (See Note 15 below.)

At December 31, 2010 and 2009, "other" primarily consisted of balancing accounts that track recovery of the authorized revenue requirements and costs related to the SmartMeter™ advanced metering project.

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)	**2010**	2009
PG&E Corporation		
Convertible subordinated notes, 9.50%, due 2010	$ —	$ 247
Less: current portion	—	(247)
Total convertible subordinated notes	—	—
Senior notes, 5.75%, due 2014	**350**	350
Unamortized discount	**(1)**	(2)
Total senior notes	**349**	348
Total PG&E Corporation long-term debt, net of current portion	**349**	348
Utility		
Senior notes:		
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
3.50% due 2020	**800**	—
6.05% due 2034	**3,000**	3,000
5.80% due 2037	**950**	700
6.35% due 2038	**400**	400
6.25% due 2039	**550**	550
5.40% due 2040	**800**	550
Less: current portion	**(500)**	—
Unamortized discount, net of premium	**(52)**	(35)
Total senior notes	**9,348**	8,565
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 (3)	**200**	200
Series 2004 A–D, 4.75%, due 2023 (3)	**345**	345
Series 2008 G and F, 3.75% (4), due 2018 and 2026	—	95
Series 2009 A–D, variable rates (5), due 2016 and 2026 (6)	**309**	309
Series 2010 E, 2.25%, due 2026 (7)	**50**	—
Less: current portion	**(309)**	(95)
Total pollution control bonds	**1,209**	1,468
Total Utility long-term debt, net of current portion	**10,557**	10,033
Total consolidated long-term debt, net of current portion	**$ 10,906**	$ 10,381

(1) At December 31, 2010, interest rates on these bonds and the related loans ranged from 0.26% to 0.31%.

(2) Each series of these bonds is supported by a separate direct-pay 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) The Utility has obtained credit support from insurance companies for these bonds.

(4) These bonds bore interest at 3.75% per year through September 19, 2010, and were subject to mandatory tender on September 20, 2010. The Utility repurchased these bonds on September 20, 2010.

(5) At December 31, 2010, interest rates on these bonds and the related loans ranged from 0.22% to 0.29%.

(6) 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.

(7) These bonds bear interest at 2.25% per year through April 1, 2012; are subject to mandatory tender on April 2, 2012; and may be remarketed in a fixed or variable rate mode.

PG&E CORPORATION

Convertible Subordinated Notes

PG&E Corporation issued 16,370,779 shares of common stock upon conversion of the $247 million principal amount of PG&E Corporation's 9.5% Convertible Subordinated Notes at a conversion price of $15.09 per share between June 23 and June 29, 2010. These notes were no longer outstanding as of December 31, 2010.

UTILITY

Senior Notes

On April 1, 2010, the Utility issued $250 million principal amount of 5.8% Senior Notes due March 1, 2037.

On September 15, 2010, the Utility issued $550 million principal amount of 3.5% Senior Notes due October 1, 2020.

On November 18, 2010, the Utility issued $250 million principal amount of 3.5% Senior Notes due October 1, 2020 and $250 million of 5.4% Senior Notes due January 15, 2040.

Pollution Control Bonds

The California Pollution Control Financing Authority and the California Infrastructure and Economic Development Bank have issued various series of fixed rate and multi-modal 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 2010 E 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, which currently bear interest at variable rates, 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.

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 April 8, 2010, the California Infrastructure and Economic Development Bank issued $50 million of tax-exempt pollution control bonds Series 2010 E due November 1, 2026 and loaned the proceeds to the Utility. The proceeds were used to refund the corresponding related series of pollution control bonds issued in 2005 that were repurchased by the Utility in 2008. The Series 2010 E bonds bear interest at 2.25% per year through April 1, 2012 and are subject to mandatory tender on April 2, 2012 at a price of 100% of the principal amount plus accrued interest. Thereafter, this series of bonds may be remarketed in a fixed or variable rate mode. Interest is currently payable semi-annually in arrears on April 1 and October 1.

On September 20, 2010, the Utility repurchased $50 million principal amount of pollution control bonds Series 2008 F and $45 million principal amount of pollution control bonds Series 2008 G that were subject to mandatory tender on the same date. The Utility, as bondholder, will be both the payer and the recipient of principal and interest payments until the bonds are remarketed to the public. As of December 31, 2010, the bonds have not been remarketed to the public.

All of the pollution control bonds were used to finance or refinance pollution control and sewage and solid waste disposal 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 the Internal Revenue Code of 1954, as amended. 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. The Utility has no knowledge that Geysers Power Company, LLC intends to cease using the bond-financed facilities solely as pollution control facilities.

REPAYMENT SCHEDULE

PG&E Corporation's and the Utility's combined aggregate principal repayment amounts of long-term debt at December 31, 2010 are reflected in the table below:

(in millions, except interest rates)	2011	2012	2013	2014	2015	Thereafter	Total
Long-term debt:							
PG&E Corporation							
Average fixed interest rate	–	–	–	5.75%	–	–	5.75%
Fixed rate obligations	$ –	$ –	$ –	$ 350	$ –	$ –	$ 350
Utility							
Average fixed interest rate	4.20%	2.25%	6.25%	4.80%	–	5.85%	5.67%
Fixed rate obligations	$ 500	$ 50 (2)	$ 400	$ 1,000	$ –	$ 8,545	$ 10,495
Variable interest rate as of December 31, 2010	0.27%	0.28%	–	–	–	–	0.28%
Variable rate obligations	$ 309 (1)	$ 614 (3)	$ –	$ –	$ –	$ –	$ 923
Less: current portion	(809)	–	–	–	–	–	(809)
Total consolidated long-term debt	$ –	$ 664	$ 400	$ 1,350	$ –	$ 8,545	$ 10,959

(1) These bonds, due from 2016 through 2026, are backed by direct-pay letters of credit that expire 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) These bonds, due in 2026, are subject to mandatory tender on April 2, 2012 and may be remarketed in a fixed or variable rate mode. Accordingly, the bonds have been classified for repayment purposes in 2012.

(3) These bonds, due in 2026, are backed by direct-pay 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 borrowings on outstanding credit facilities at December 31, 2010:

(in millions)	Termination Date	Facility Limit	Letters of Credit Outstanding	Cash Borrowings	Commercial Paper Backup	Availability
PG&E Corporation	February 2012	$ 187 (1)	$ –	$ –	N/A	$ 187
Utility	February 2012	1,940 (2)	329	–	$ 603	1,008
Utility	February 2012	750 (3)	N/A	–	–	750
Total credit facilities		$ 2,877	$ 329	$ –	$ 603	$ 1,945

(1) Includes a $87 million sublimit for letters of credit and a $100 million commitment 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 commitment for swingline loans.

(3) Includes a $75 million commitment 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. 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 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, 2010, PG&E Corporation met both of these tests.

UTILITY

Revolving credit facilities

The Utility has a $1.9 billion revolving credit facility with a syndicate of lenders that expires on February 26, 2012. 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.

On June 8, 2010, the Utility entered into a $750 million unsecured revolving credit agreement with a syndicate of lenders. Of the total credit capacity, $500 million was used to replace the $500 million Floating Rate Senior Notes that matured on June 10, 2010. The aggregate facility of $750 million includes a $75 million commitment for swingline loans, or loans that are made available on a same-day basis and are repayable in full within 30 days. The Utility can, at any time, repay amounts outstanding in whole or in part. The credit agreement expires on February 26, 2012, unless extended for additional periods at the Utility's request and at the sole discretion of each lender.

Borrowings under the credit agreement (other than swingline loans) will bear interest based, at the Utility's election, at (1) London Interbank Offered Rate ("LIBOR") plus an applicable margin or (2) the base rate, which will equal the higher of the (i) administrative agent's announced base rate, (ii) 0.5% above the federal funds rate, or (iii) the one-month LIBOR plus an applicable margin. Interest is payable quarterly in arrears, or earlier for loans with shorter interest periods. The Utility also will pay a facility fee on the total commitments of the lenders under the credit agreement. The applicable margin for LIBOR loans and the facility fee will be based on the Utility's senior unsecured, non-credit enhanced debt ratings issued by S&P and Moody's. Facility fees are payable quarterly in arrears.

The Utility treats the amount of its outstanding commercial paper as a reduction to the amount available under its revolving credit facilities so that liquidity from the revolving credit facility is available to repay outstanding commercial paper.

The revolving credit facilities include usual and customary covenants for credit facilities of this type, including covenants limiting liens to those permitted under the senior note indenture, mergers, sales of all or substantially all of the Utility's assets, and other fundamental changes. Both the $750 million and $1.9 billion revolving credit facilities require that the Utility maintain a ratio of total consolidated debt to total consolidated capitalization of, at most, 65% as of the end of each fiscal quarter. At December 31, 2010, 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 facilities, 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, 2010, the average yield was 0.51%.

Other Short-term Borrowings

On October 12, 2010, the Utility issued $250 million principal amount of Floating Rate Senior Notes due October 11, 2011. The interest rate for the Floating Rate Senior Notes is equal to the three-month LIBOR plus 0.58% and will reset quarterly beginning on January 11, 2011. At December 31, 2010, the interest rate on the Floating Rate Senior Notes was 0.87%. On January 11, 2011, the interest rate was reset to 0.88%.

NOTE 5: ENERGY RECOVERY BONDS

In 2005, PERF 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 two outstanding classes are 4.37% for the earlier maturing class and 4.47% for the later 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 earlier maturing class and 5.12% for the later 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 $827 million at December 31, 2010 and $1.2 billion at December 31, 2009. The scheduled principal repayments for ERBs are reflected in the table below:

(in millions)	2011	2012	Total
Utility			
Average fixed interest rate	4.59%	4.66%	4.63%
Energy recovery bonds	$ 404	$ 423	$ 827

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 AND SHARE-BASED COMPENSATION

PG&E CORPORATION

Of the 395,227,205 shares of PG&E Corporation common stock outstanding at December 31, 2010, 475,880 shares were granted as restricted stock under the PG&E Corporation Long-Term Incentive Program and the 2006

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Long-Term Incentive Plan ("2006 LTIP"), and 5,105,505 shares were issued for the accounts of participants in PG&E Corporation's 401(k) plan and Dividend Reinvestment and Stock Purchase Plan ("DRSPP"). In addition, between June 23 and June 29, 2010, PG&E Corporation issued 16,370,779 shares of common stock upon conversion of the $247 million principal amount of Convertible Subordinated Notes. (See Note 4 above.)

On November 4, 2010, PG&E Corporation entered into an Equity Distribution Agreement pursuant to which PG&E Corporation's sales agents may offer and sell, from time to time, PG&E Corporation common stock having an aggregate gross offering price of up to $400 million. Sales of the shares are made by means of ordinary brokers' transactions on the New York Stock Exchange, or in such other transactions as agreed upon by PG&E Corporation and the sales agents and in conformance with applicable securities laws. As of December 31, 2010, PG&E Corporation had issued 2,357,796 shares of its common stock pursuant to the Equity Distribution Agreement for cash proceeds of $110 million, net of fees and commissions paid of $1 million.

UTILITY

As of December 31, 2010, PG&E Corporation held all of the Utility's outstanding common stock.

DIVIDENDS

The Boards of Directors of PG&E Corporation and the Utility have each adopted a dividend policy. Under the Utility's Articles of Incorporation, the Utility cannot pay common stock dividends unless all cumulative preferred dividends on the Utility's preferred stock have been paid.

PG&E Corporation and the Utility each have revolving credit facilities that require the company to maintain a ratio of consolidated total debt to consolidated capitalization of at most 65%. This covenant, along with the CPUC's requirement for the Utility to maintain the 52% equity component of its capital structure, are considered to be restrictions on the payment of dividends. Based on the calculation of these ratios for each company, no amount of PG&E Corporation's retained earnings and $5.3 billion of the Utility's retained earnings were restricted at December 31, 2010.

In addition, the Utility was required to maintain at least $9.7 billion of its net assets as equity in order to maintain the capital structure of at least 52% equity at December 31, 2010. As a result, $9.7 billion of the Utility's net assets are restricted and may not be transferred to PG&E Corporation in the form of cash dividends.

The Boards of Directors of PG&E Corporation and the Utility declare dividends quarterly. On December 15, 2010, the Board of Directors of PG&E Corporation declared a quarterly dividend of $0.455 per share, totaling $183 million, which was paid on January 15, 2011 to shareholders of record on December 31, 2010.

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) has been reserved for issuance under the 2006 LTIP, of which 7,856,348 shares were available for award at December 31, 2010.

Awards made under the PG&E Corporation LTIP before December 31, 2005 and still outstanding continue to be governed by the terms and conditions of the PG&E Corporation LTIP.

PG&E Corporation and the Utility use an estimated annual forfeiture rate of 2.5% for stock options and restricted stock and 2% 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 2010, 2009, and 2008:

(in millions)	**2010**	2009	2008
Stock Options	**$ –**	$ –	$ 2
Restricted Stock	**14**	9	22
Restricted Stock Units	**9**	11	–
Performance Shares:			
Liability Awards	**22**	37	33
Equity Awards	**11**	–	–
Total Compensation Expense (pre-tax)	**$ 56**	$ 57	$ 57
Total Compensation Expense (after-tax)	**$ 33**	$ 34	$ 34

There were no significant stock-based compensation costs capitalized during 2010, 2009 and 2008. There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

Stock Options

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 following table summarizes total intrinsic value (fair market value of PG&E Corporation's common stock less exercise price) of options exercised:

	PG&E Corporation		
(in millions)	2010	2009	2008
Intrinsic value of options exercised	$ 15	$ 18	$ 13

The tax benefit from stock options exercised totaled $0.5 million, $6 million, and $4 million for 2010, 2009, and 2008 respectively.

The following table summarizes stock option activity for 2010:

Options	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1	1,975,341	$ 23.99		
Granted	1,742	42.97		
Exercised	(605,585)	22.67		
Forfeited or expired	(1,587)	30.13		
Outstanding at December 31	**1,369,911**	**25.16**	**2.76**	**$ 31,068,628**
Expected to vest at December 31	**21,401**	**37.77**	**7.89**	**$ 215,584**
Exercisable at December 31	**1,348,510**	**$ 24.96**	**2.68**	**$ 30,853,045**

As of December 31, 2010, there was less than $1 million of total unrecognized compensation cost related to outstanding stock options.

Restricted Stock

During 2010, PG&E Corporation awarded 10,540 shares of restricted common stock to eligible participants under the 2006 LTIP. The terms of the restricted stock award agreements provide that the shares will vest over a five-year period. Although the recipients of restricted stock possess voting rights, they may not sell or transfer their shares until the shares vest.

Prior to 2010, PG&E Corporation also awarded restricted stock to eligible employees under the 2006 LTIP. The terms of these restricted stock award agreements 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 that 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 weighted average grant-date fair value per-share of restricted stock granted during 2010, 2009, and 2008 was $42.97, $35.53, and $37.91, respectively. The total fair value of restricted stock that vested during 2010, 2009, and 2008 was $8 million, $24 million, and $19 million, respectively. The tax benefit from restricted stock that vested during 2010, 2009, and 2008 was not material.

The following table summarizes restricted stock activity for 2010:

	Number of Shares of Restricted Stock	Weighted Average Grant-Date Fair Value
Nonvested at January 1	670,552	$ 41.11
Granted	10,540	$ 42.97
Vested	(189,976)	$ 41.70
Forfeited	(15,236)	$ 42.52
Nonvested at December 31	**475,880**	**$ 40.87**

As of December 31, 2010, there was less than $1 million of total unrecognized compensation cost relating to restricted stock.

Restricted Stock Units

Beginning January 1, 2009, PG&E Corporation primarily awarded restricted stock units ("RSUs") instead of restricted stock as permitted by the 2006 LTIP. RSUs are hypothetical shares of stock that will generally vest in 20% increments on the first business day of March in year one, two, and three, with the remaining 40% vesting on the first business day of March in year four. 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.

The weighted average grant-date fair value per RSU granted during 2010 and 2009 was $42.97 and $35.53, respectively. The total fair value of RSUs that vested during 2010 and 2009 was $5 million and less than $1 million, respectively. As of December 31, 2010, $21 million of total unrecognized compensation costs related to nonvested RSUs are expected to be recognized over the remaining weighted average period of 2.70 years.

The following table summarizes RSU activity for 2010:

	Number of Restricted Stock Units	Weighted Average Grant-Date Fair Value
Nonvested at January 1	664,992	$ 35.78
Granted	640,060	$ 42.97
Vested	(125,651)	$ 35.60
Forfeited	(25,005)	$ 37.61
Nonvested at December 31	**1,154,396**	**$ 39.74**

Performance Shares

On March 10, 2010, PG&E Corporation granted 605,275 contingent performance shares to eligible employees under the 2006 LTIP. Unlike performance shares awarded in prior periods (see below), which settle in cash, 2010 grants will be settled in PG&E Corporation common stock and are classified as share-based equity awards. Performance shares granted and outstanding prior to 2010 will not be modified and will continue to be paid and settled in cash. The vesting of the performance shares granted in 2010 is dependent upon three years of continuous service. Additionally the amount of common stock that recipients are entitled to receive, if any, will be determined based on PG&E Corporation's TSR relative to the performance of a specified group of peer companies for the applicable three-year performance period. Total compensation expense for these shares is based on the grant-date fair value, which is determined using a Monte Carlo simulation valuation model. Performance share expense is recognized ratably over the requisite service period based on the fair values determined, except for the expense attributable to awards granted to retirement-eligible participants, which is recognized on the date of grant. Dividend equivalents on equity-classified awards, if any, will be paid in cash upon vesting date based on the amount of common stock awarded.

For performance shares classified as equity awards, the following table summarizes activity for 2010:

	Number of Performance Shares	Weighted Average Grant-Date Fair Value
Nonvested at January 1	–	
Granted	616,990	$ 35.60
Vested	–	
Forfeited	(7,020)	$ 35.60
Nonvested at December 31	**609,970**	**$ 35.60**

As of December 31, 2010, $10 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted-average period of 1.22 years.

Prior to 2010, PG&E Corporation awarded performance shares to eligible participants under the 2006 LTIP as hypothetical shares of common stock that vest at the end of a three-year period and are settled in cash based on the performance of PG&E Corporation's TSR. 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 in the three-year performance period. This result is then adjusted based on PG&E Corporation's TSR relative to the performance of a specified group of peer companies for the applicable three-year performance period. These outstanding performance shares are classified as a liability because the performance shares can only be settled in cash. During each reporting period compensation expense recognized for performance shares will fluctuate based on PG&E Corporation's common stock price and its TSR relative to its comparator group. As of December 31, 2010 and 2009, $68 million and $63 million, respectively, had been accrued as the performance share liability for PG&E Corporation.

For performance shares classified as liability awards, the following table summarizes activity for 2010:

	Number of Performance Shares	Weighted Average Fair Value
Nonvested at January 1	1,547,598	$ 55.98
Granted	–	
Vested	(387,019)	$ 43.06
Forfeited	(23,089)	$ 56.18
Nonvested at December 31	**1,137,490**	**$ 60.37**

For performance shares classified as liability awards, the total intrinsic value of amounts settled during 2010, 2009, and 2008 was $17 million, $21 million, and $7 million, respectively.

NOTE 7: PREFERRED STOCK

PG&E CORPORATION

PG&E Corporation has authorized 80 million shares of no par value preferred stock and 5 million shares of $100 par value 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 outstanding preferred stock without mandatory redemption provisions at December 31, 2010 and 2009:

(in millions, except share amounts, redemption price, and par value)	Shares Outstanding	Redemption Price	Balance
Nonredeemable $25 par value preferred stock			
5.00% Series	400,000	N/A	$ 10
5.50% Series	1,173,163	N/A	30
6.00% Series	4,211,662	N/A	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
Preferred stock			$ 258

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, 2010, 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. 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. During each of 2010, 2009, and 2008, the Utility paid $14 million of dividends on preferred stock. On December 15, 2010, 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, 2011 to preferred shareholders of record on January 31, 2011. On February 16, 2011, the Board of Directors of the Utility declared a cash dividend on its outstanding series of preferred stock, payable on May 15, 2011, to shareholders of record on April 29, 2011.

NOTE 8: EARNINGS PER SHARE

PG&E Corporation's earnings per common share ("EPS") is calculated utilizing the "two-class" method by dividing the sum of distributed earnings to common shareholders and undistributed earnings allocated to common shareholders by the weighted average number of common shares outstanding during the period. In applying the two-class method, undistributed earnings are allocated to both common shares and participating securities. PG&E Corporation's Convertible Subordinated Notes met the criteria of participating securities as the holders were entitled to receive dividends similar to holders of common stock.

As of June 29, 2010, all of PG&E Corporation's Convertible Subordinated Notes had been converted into common stock. Therefore, there were no participating securities outstanding at December 31, 2010. (See Note 4 above.)

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)	**2010**	2009	2008
Basic			
Income available for common shareholders	**$ 1,099**	$ 1,220	$ 1,338
Less: distributed earnings to common shareholders	**706**	621	560
Undistributed earnings	**393**	599	778
Less: undistributed earnings from discontinued operations	**–**	–	154
Undistributed earnings from continuing operations	**$ 393**	$ 599	$ 624
Allocation of undistributed earnings to common shareholders			
Distributed earnings to common shareholders	**$ 706**	$ 621	$ 560
Undistributed earnings allocated to common shareholders – continuing operations	**385**	573	592
Undistributed earnings allocated to common shareholders – discontinued operations	**–**	–	146
Total common shareholders earnings	**$ 1,091**	$ 1,194	$ 1,298
Weighted average common shares outstanding, basic	**382**	368	357
Convertible subordinated notes	**8**	17	19
Weighted average common shares outstanding and participating securities	**390**	385	376
Net earnings per common share, basic			
Distributed earnings, basic[1]	**$ 1.85**	$ 1.69	$ 1.57
Undistributed earnings – continuing operations, basic	**1.01**	1.56	1.66
Undistributed earnings – discontinued operations, basic	**–**	–	0.41
Total	**$ 2.86**	$ 3.25	$ 3.64

(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 during the period PG&E Corporation's Convertible Subordinated Notes were outstanding, PG&E Corporation applied 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:

	Year ended December 31,	
(in millions, except per share amounts)	**2010**	2009
Diluted		
Income available for common shareholders	**$ 1,099**	$ 1,220
Add earnings impact of assumed conversion of participating securities:		
Interest expense on convertible subordinated notes, net of tax	**8**	15
Unrealized loss on embedded derivative, net of tax	**–**	2
Income available for common shareholders and assumed conversion	**$ 1,107**	$ 1,237
Weighted average common shares outstanding, basic	**382**	368
Add incremental shares from assumed conversions:		
Convertible subordinated notes	**8**	17
Employee share-based compensation	**2**	1
Weighted average common shares outstanding, diluted	**392**	386
Total earnings per common share, diluted	**$ 2.82**	$ 3.20

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:

(in millions, except per share amounts)	Year ended December 31, 2008
Diluted	
Income available for common shareholders	$ 1,338
Less: distributed earnings to common shareholders	560
Undistributed earnings	778
Less: undistributed earnings from discontinued operations	154
Undistributed earnings from continuing operations	$ 624
Allocation of undistributed earnings to common shareholders	
Distributed earnings to common shareholders	$ 560
Undistributed earnings allocated to common shareholders – continuing operations	593
Undistributed earnings allocated to common shareholders – discontinued operations	146
Total common shareholders earnings	$ 1,299
Weighted average common shares outstanding, basic	357
Convertible subordinated notes	19
Weighted average common shares outstanding and participating securities, basic	376
Weighted average common shares outstanding, basic	357
Employee share-based compensation	1
Weighted average common shares outstanding, diluted	358
Convertible subordinated notes	19
Weighted average common shares outstanding and participating securities, diluted	377
Net earnings per common share, diluted	
Distributed earnings, diluted	$ 1.56
Undistributed earnings – continuing operations, diluted	1.66
Undistributed earnings – discontinued operations, diluted	0.41
Total earnings per common share, diluted	$ 3.63

For each of the periods presented above, the calculation of outstanding shares on a diluted basis excluded an insignificant amount of options and securities that were antidilutive.

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)	**2010**	2009	2008	**2010**	2009	2008
Current:						
Federal	**$ (12)**	$ (747)	$(268)	**$ (54)**	$ (696)	$ (188)
State	**130**	(41)	33	**134**	(45)	24
Deferred:						
Federal	**525**	1,161	604	**589**	1,139	596
State	**(91)**	92	62	**(90)**	89	62
Tax credits	**(5)**	(5)	(6)	**(5)**	(5)	(6)
Income tax provision	**$ 547**	$ 460	$ 425	**$ 574**	$ 482	$ 488

The following describes net deferred income tax liabilities:

	PG&E Corporation		Utility	
	Year Ended December 31,			
(in millions)	**2010**	2009	**2010**	2009
Deferred income tax assets:				
Reserve for damages	**$ 222**	$ 138	**$ 222**	$ 138
Environmental reserve	**242**	227	**242**	227
Compensation	**345**	338	**305**	304
Net operating loss carry forward	**327**	–	**270**	–
Other	**207**	184	**178**	180
Total deferred income tax assets	**$ 1,343**	$ 887	**$ 1,217**	$ 849
Deferred income tax liabilities:				
Regulatory balancing accounts	**$ 1,116**	$ 1,340	**$ 1,116**	$ 1,340
Property related basis differences	**5,236**	4,036	**5,234**	4,032
Income tax regulatory asset	**509**	418	**509**	418
Other	**142**	157	**135**	157
Total deferred income tax liabilities	**$ 7,003**	$ 5,951	**$ 6,994**	$ 5,947
Total net deferred income tax liabilities	**$ 5,660**	$ 5,064	**$ 5,777**	$ 5,098
Classification of net deferred income tax liabilities:				
Included in current liabilities	**$ 113**	$ 332	**$ 118**	$ 334
Included in noncurrent liabilities	**5,547**	4,732	**5,659**	4,764
Total net deferred income tax liabilities	**$ 5,660**	$ 5,064	**$ 5,777**	$ 5,098

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,					
	2010	2009	2008	**2010**	2009	2008
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)	**0.7**	1.6	3.1	**1.0**	1.4	3.3
Effect of regulatory treatment of fixed asset differences	**(3.1)**	(2.7)	(3.2)	**(3.0)**	(2.6)	(3.1)
Tax credits	**(0.4)**	(0.5)	(0.5)	**(0.4)**	(0.5)	(0.5)
IRS audit settlements	**0.1**	(4.5)	(7.1)	**(0.2)**	(4.2)	(4.1)
Other, net	**0.9**	(1.5)	(0.9)	**1.5**	(1.3)	(1.7)
Effective tax rate	**33.2%**	27.4%	26.4%	**33.9%**	27.8%	28.9%

Unrecognized tax benefits

The following table reconciles the changes in unrecognized tax benefits:

	PG&E Corporation			Utility		
	2010	2009	2008	**2010**	2009	2008
(in millions)						
Balance at beginning of year	**$ 673**	$ 75	$ 209	**$ 652**	$ 37	$ 94
Additions for tax position taken during a prior year	**27**	4	–	**27**	4	–
Additions for tax position taken during the current year	**89**	624	43	**87**	623	20
Settlements	**(55)**	(27)	(177)	**(54)**	(12)	(77)
Reductions for tax position taken during a prior year	**(20)**	(3)	–	**–**	–	–
Balance at end of year	**$ 714**	$ 673	$ 75	**$ 712**	$ 652	$ 37

The component of unrecognized tax benefits that, if recognized, would affect the effective tax rate at December 31, 2010 for PG&E Corporation and the Utility is $39 million, with the remaining balance representing the probable deferral of taxes to later years. PG&E Corporation and the Utility do not expect that the total unrecognized tax benefits would significantly change within the next 12 months.

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 net of penalties recognized in income tax expense by PG&E Corporation in 2010, 2009, and 2008 was $3 million, $19 million, and $24 million, respectively. Interest income net of penalties recognized in income tax expense by the Utility in 2010, 2009, and 2008 was $3 million, $14 million, and $11 million, respectively.

As of December 31, 2010, PG&E Corporation and the Utility had accrued interest income of $8 million. As of December 31, 2009, PG&E Corporation and the Utility had accrued interest expense and penalties of $11 million and $12 million, respectively.

Federal subsidy for Medicare Part D

PG&E Corporation and the Utility receive a federal subsidy for maintaining a retiree medical benefit plan with prescription drug benefits that is actuarially equivalent to Medicare Part D. For federal income tax purposes, the subsidy was deductible when contributed to the benefit plan maintained for these benefits. On March 30, 2010, federal health care legislation was signed eliminating the deduction for subsidy contributions after 2012. As a result, PG&E Corporation and the Utility recognized an expense of $19 million in 2010 to reverse previously recognized federal tax benefits (recorded as an increase to income tax provision and a reduction to deferred income tax assets for subsidy amounts included in the calculation of accrued retiree medical benefit obligation).

Tax settlements and years that remain subject to examination

On September 29, 2010, PG&E Corporation received the Internal Revenue Service ("IRS") examination report for the 2005 to 2007 audit years and resolved all matters except for a few items that will be discussed with the IRS Appeals office. Included in the 2005 to 2007 audit was the resolution of the change in accounting method related to the capitalization of indirect service costs for those years. As a result, PG&E Corporation recorded a $25 million reduction to income tax expense during 2010.

In tax year 2008, PG&E Corporation began participating in the Compliance Assurance Process ("CAP"), a real-time IRS audit intended to expedite resolution of tax matters. The CAP audit culminates with a letter from the IRS indicating their acceptance of the return. The IRS partially accepted the 2008 return, withholding two issues for further review. The most significant of these relates to a tax accounting method change filed by PG&E Corporation to accelerate the amount of deductible repairs. While the IRS approved PG&E Corporation's request for a change in method, the IRS will audit the methodology to determine the proper deduction. This audit has not progressed significantly because the IRS is working with the utility industry to resolve this matter in a consistent manner for all utilities before auditing individual companies. On December 14, 2010 the IRS accepted PG&E Corporation's 2009 tax return without change.

In 2009, PG&E Corporation recognized an income tax benefit of $56 million from settling a claim with the 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 California Franchise Tax Board is auditing PG&E Corporation's 2004 and 2005 combined California income tax returns, as well as the 1997-2007 amended income tax returns reflecting IRS settlements for these years and claim filings that apply only to California. It is uncertain when the California Franchise Tax Board will complete the audits.

PG&E Corporation believes that the 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.

Loss carry forwards

As of December 31, 2010 and 2009, PG&E Corporation has $24 million and $25 million, respectively, of federal and California capital loss carry forwards based on filed tax returns, of which approximately $9 million will expire if not used by December 31, 2011. For all periods presented, PG&E Corporation has provided a full valuation allowance against its deferred income tax assets for capital loss carry forwards.

The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (the "Tax Relief Act") Federal legislation that was signed into law on December 17, 2010, provides for full expensing of qualified property, plant, and equipment placed in service from September 9, 2010 to December 31, 2011 for tax purposes. The Tax Relief Act increased PG&E Corporation's federal net operating loss carry forwards. As of December 31, 2010, PG&E Corporation has approximately $540 million of federal net operating loss carry forwards and $45 million of tax credit carry forwards, which will expire between 2029 and 2030. In addition, PG&E Corporation has approximately $46 million of loss carry forwards related to charitable contributions, which will expire between 2014 and 2015. PG&E Corporation believes it is more likely than not the tax benefits associated with the federal operating loss and tax credit can be realized within the carry forward periods; therefore, no valuation allowance was recognized as of December 31, 2010. The amount of federal net operating loss carry forwards for which a tax benefit from employee stock plans would be recorded in additional paid-in capital was approximately $9 million as of December 31, 2010.

NOTE 10: DERIVATIVES AND HEDGING ACTIVITIES

USE OF DERIVATIVE INSTRUMENTS

The Utility faces market risk primarily related to electricity and natural gas commodity prices. All of the Utility's risk management activities involving derivatives reduce the volatility of commodity costs on behalf of its customers. The CPUC allows 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.

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 committing the Utility to 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. 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 change in fair value of these derivative instruments are deferred and recorded within the Utility's regulatory assets and liabilities on the Consolidated Balance Sheets. (See Note 3 above.) 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.

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 or contracted resources to generate power.

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. The Utility elects to use the normal purchase and sale exception for eligible derivative instruments.

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

Electric Transmission Congestion Revenue Rights
The California Independent System Operator ("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 congestion revenue rights ("CRRs") 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). The CRRs held by the Utility are considered derivative instruments.

Natural Gas Procurement (Electric Fuels 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 volatility in customer rates, the Utility purchases financial instruments such as futures, swaps, and options to reduce future cash flow variability associated with fluctuating natural gas prices. These financial instruments are considered derivative instruments.

Natural Gas Procurement (Core Gas Supply Portfolio)
The Utility enters into physical natural gas commodity contracts to fulfill the needs of its residential and smaller commercial customers known as "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 multi-month, monthly and, to a lesser extent, daily spot market to balance such seasonal supply and demand. The Utility purchases financial instruments such as swaps and options as part of its core winter hedging program in order to manage customer exposure to high gas prices during peak winter months. These financial instruments are considered derivative instruments.

VOLUME OF DERIVATIVE ACTIVITY

At December 31, 2010, the volumes of PG&E Corporation's and the Utility's outstanding derivative contracts were 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	427,176,587	308,712,558	–	–
	Options	270,509,308	176,150,000	–	–
Electricity (Megawatt-hours)	Forwards, Futures, and Swaps	5,690,441	6,969,024	3,673,512	4,826,640
	Options	415,450	–	264,096	396,396
	Congestion Revenue Rights	74,313,524	72,070,789	71,997,921	96,986,809

(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 2016 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 under a master netting agreement. The net balances include outstanding cash collateral associated with derivative positions.

At December 31, 2010, 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 the Utility)				
Current assets – other	$ 56	$(45)	$ 79	$ 90
Other noncurrent assets – other	77	(62)	96	111
Current liabilities – other	(388)	45	119	(224)
Noncurrent liabilities – other	(486)	62	130	(294)
Total commodity risk	$ (741)	$ –	$ 424	$ (317)

(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.

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 the Utility)				
Current assets – 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, which were converted to PG&E Corporation common stock in 2010.

For the years ended December 31, 2010 and 2009, the gains and losses recorded on PG&E Corporation's and the Utility's derivative instruments were as follows:

	Commodity Risk (PG&E Corporation and the Utility)	
(in millions)	2010	2009
Unrealized gain/(loss) – Regulatory assets and liabilities (1)	**$ (260)**	$ 15
Realized gain/(loss) – Cost of electricity (2)	**(573)**	(701)
Realized gain/(loss) – Cost of natural gas (2)	**(79)**	(54)
Total commodity risk instruments	**$ (912)**	$ (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 included 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, 2010, 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	$ (518)
Related derivatives in an asset position	–
Collateral posting in the normal course of business related to these derivatives	7
Net position of derivative contracts/additional collateral posting requirements [1]	$ (511)

(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 measure their cash equivalents, trust assets, and price risk management instruments at fair value. Fair value is an exit price, representing the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. As such, fair value is a market-based measurement that should be determined based on assumptions that market participants would use in pricing an asset or a liability. A three-tier fair value hierarchy is established as a basis for considering such assumptions and for inputs used in the valuation methodologies in measuring fair value:

Level 1—Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.

Level 2—Other inputs that are directly or indirectly observable in the marketplace.

Level 3—Unobservable inputs that are supported by little or no market activities.

The fair value hierarchy requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

Assets and liabilities measured at fair value on a recurring basis for PG&E Corporation and the Utility are summarized below (money market investments and assets held in rabbi trusts are held by PG&E Corporation and not the Utility):

	Fair Value Measurements at December 31, 2010			
(in millions)	Level 1	Level 2	Level 3	Total
Assets:				
Money market investments	$ 138	$ –	$ –	$ 138
Nuclear decommissioning trusts				
U.S. equity securities (1)	1,029	7	–	1,036
Non-U.S. equity securities	349	–	–	349
U.S. government and agency securities	584	40	–	624
Municipal securities	–	119	–	119
Other fixed income securities	–	66	–	66
Total nuclear decommissioning trusts (2)	1,962	232	–	2,194
Price risk management instruments (Note 10)				
Electric (3)	130	–	–	130
Gas (4)	3	–	–	3
Total price risk management instruments	133	–	–	133
Rabbi trusts				
Fixed income securities	–	24	–	24
Life insurance contracts	–	65	–	65
Total rabbi trusts	–	89	–	89
Long-term disability trust				
U.S. equity securities (1)	11	24	–	35
Corporate debt securities (1)	–	150	–	150
Total long-term disability trust	11	174	–	185
Total assets	$ 2,244	$ 495	$ –	$ 2,739
Liabilities:				
Price risk management instruments (Note 10)				
Electric (5)	$ –	$ 5	$ 403	$ 408
Gas (6)	–	1	41	42
Total price risk management instruments	–	6	444	450
Total liabilities	$ –	$ 6	$ 444	$ 450

(1) Level 2 balances include commingled funds, which are composed primarily of securities traded publicly on exchanges. Price quotes for the assets held by the funds are readily observable and available.

(2) Excludes $185 million primarily related to deferred taxes on appreciation of investment value.

(3) Balances include the impact of netting adjustments of $359 million to Level 1. Includes natural gas for electric portfolio.

(4) Balances include the impact of netting adjustments of $44 million to Level 1. Includes natural gas for core customers.

(5) Balances include the impact of netting adjustments of $66 million to Level 2 and $(48) million to Level 3. Includes natural gas for electric portfolio.

(6) Balances include the impact of netting adjustments of $3 million to Level 3. Includes natural gas for core customers.

Fair Value Measurements at December 31, 2009				
(in millions)	Level 1	Level 2	Level 3	Total
Assets:				
Money market investments	$ 189	$ –	$ 4	$ 193
Nuclear decommissioning trusts				
U.S. equity securities (1)	762	6	–	768
Non-U.S. equity securities	344	–	–	344
U.S. government and agency securities	653	51	–	704
Municipal securities	1	89	–	90
Other fixed income securities	–	108	–	108
Total nuclear decommissioning trusts (2)	1,760	254	–	2,014
Rabbi trusts				
Equity securities	21	–	–	21
Life insurance contracts	60	–	–	60
Total rabbi trusts	81	–	–	81
Long-term disability trust				
U.S. equity securities (1)	52	23	–	75
Corporate debt securities (1)	–	113	–	113
Total long-term disability trust	52	136	–	188
Total assets	$ 2,082	$ 390	$ 4	$ 2,476
Liabilities:				
Dividend participation rights (3)	$ –	$ –	$ 12	$ 12
Price risk management instruments (Note 10)				
Electric (4)	2	73	157	232
Gas (5)	1	–	60	61
Total price risk management instruments	3	73	217	293
Other liabilities	–	–	3	3
Total liabilities	$ 3	$ 73	$ 232	$ 308

(1) Level 2 balances include commingled funds, which are composed primarily of securities traded publicly on exchanges. Price quotes for the assets held by the funds are readily observable and available.

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

(3) The dividend participation rights were associated with PG&E Corporation's Convertible Subordinated Notes, which were no longer outstanding as of December 31, 2010.

(4) Balances include the impact of netting adjustments of $108 million to Level 1, $48 million to Level 2, and $19 million to Level 3. Includes natural gas for electric portfolio.

(5) Balances include the impact of netting adjustments of $13 million to Level 3. Includes natural gas for core customers.

MONEY MARKET INVESTMENTS

PG&E Corporation invests in 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 using unadjusted quotes in an active market for identical assets and are thus classified as Level 1 instruments. Money market funds are recorded as cash and cash equivalents in PG&E Corporation's Consolidated Balance Sheets.

TRUST ASSETS

The assets held by the nuclear decommissioning trusts, the rabbi trusts related to the non-qualified deferred compensation plans, and the long-term disability trust are composed primarily of equity securities and debt securities. In general, investments held in the trusts are exposed to various risks, such as interest rate, credit, and market volatility risks. 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.

Equity securities primarily include investments in common stock and commingled funds composed of equity across multiple industry sectors in the U.S. and other regions of the world. Equity securities are generally valued based on unadjusted prices in active markets for identical transactions and are classified as Level 1.

Debt securities are composed primarily of fixed income securities that include U.S. government and agency securities, municipal securities, and corporate debt securities. A market based valuation approach is generally used to estimate the fair value of debt securities classified as Level 2 instruments in the tables above. Under a market approach, fair values are determined based on evaluated pricing data, such as broker quotes, for similar securities adjusted for observable differences. Significant inputs used in the valuation model generally include benchmark yield curves and issuer spreads. The external credit rating, coupon rate, and maturity of each security are considered in the valuation, as applicable.

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 12 below.) 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 include physical and financial derivative contracts, such as futures, forwards, swaps, options, and CRRs that are either exchange-traded or over-the-counter traded. (See Note 10 above.)

Futures, forwards, and swaps are valued using observable market prices for the underlying commodity or an identical instrument and are classified as Level 1 or Level 2 instruments. For periods where market data is not available, the Utility extrapolates forward prices. Other futures, forwards, and swaps are considered Level 3 instruments as the determination of their fair value includes the use of unobservable forward prices.

All energy-related options are classified as Level 3 and are valued using a standard option pricing model with various assumptions, including forward prices for the underlying commodity, time value at a risk-free rate, and volatility. For periods when market data is not available, the Utility extrapolates these assumptions using internal models.

The Utility holds CRRs to hedge financial risk of CAISO-imposed congestion charges in the day-ahead markets. CRRs are valued based on the forecasted settlement price at the delivery points underlying the CRR using internal models. The Utility also uses the most current annual auction prices published by the CAISO to calibrate internal models. Limited market data is available between auction dates; therefore, CRRs are classified as Level 3 measurements.

The Utility enters into power purchase agreements for the purchase of electricity to meet the demand of its customers. (See Note 10 above.) The Utility uses internal models to determine the fair value of these power purchase agreements. These power purchase agreements include contract terms that extend beyond a period for which an active market exists. The Utility utilizes market data for the underlying commodity to the extent that it is available in determining the fair value. For periods where market data is not available, the Utility extrapolates forward prices. These power purchase agreements are considered Level 3 instruments as the determination of their fair value includes the use of unobservable forward prices.

TRANSFERS BETWEEN LEVELS

PG&E Corporation and the Utility recognize any transfers between levels in the fair value hierarchy as of the end of the reporting period. There were no significant transfers between levels for the year ended December 31, 2010.

LEVEL 3 RECONCILIATION

The following tables present reconciliations for assets and liabilities measured and recorded at fair value on a recurring basis, using significant unobservable inputs (Level 3), for the years ended December 31, 2010 and 2009:

	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 Liabilities	Total
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 into Level 3	–	–	–	–	–	–	–	–
Transfers out of Level 3	–	–	–	(6)	(23)	(113)	–	(142)
Asset (liability) balance as of December 31, 2009	$ 4	$ (12)	$ (217)	$ –	$ –	$ –	$ (3)	$ (228)
Realized and unrealized gains (losses):								
Included in earnings	–	–	–	–	–	–	–	–
Included in regulatory assets and liabilities or balancing accounts	–	–	(227)	–	–	–	3	(224)
Purchases, issuances, and settlements	(4)	12	–	–	–	–	–	8
Transfers into Level 3	–	–	–	–	–	–	–	–
Transfers out of Level 3	–	–	–	–	–	–	–	–
Asset (liability) balance as of December 31, 2010	**$ –**	**$ –**	**$ (444)**	**$ –**	**$ –**	**$ –**	**$ –**	**$ (444)**

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

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, 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, 2010 and 2009.

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, 2010 and 2009.

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

	At December 31,			
	2010		2009	
(in millions)	**Carrying Amount**	**Fair Value(2)**	Carrying Amount	Fair Value (2)
Debt (Note 4):				
PG&E Corporation (1)	**$ 349**	**$ 383**	$ 597	$ 1,096
Utility	**10,444**	**11,314**	9,240	9,824
Energy recovery bonds (Note 5)	**827**	**862**	1,213	1,269

(1) PG&E Corporation Convertible Subordinated Notes were no longer outstanding as of December 31, 2010.

(2) Fair values are determined using readily available quoted market prices.

NUCLEAR DECOMMISSIONING TRUST INVESTMENTS

The funds in the decommissioning trusts, along with accumulated earnings, will be used exclusively for decommissioning and dismantling the Utility's nuclear facilities. At December 31, 2010 and 2009, the Utility had accumulated nuclear decommissioning trust funds with an estimated fair value of $2.0 billion and $1.9 billion, respectively, net of deferred taxes on unrealized gains. In 2010 and 2009, the trusts earned $62 million and $63 million in interest and dividends, respectively. All earnings on the assets held in the trusts, net of authorized disbursements from the trusts and investment management and administrative fees, are reinvested. Amounts may not be released from the decommissioning trusts until authorized by the CPUC.

At December 31, 2010 and 2009, total unrealized losses on the investments held in the trusts were $6 million and $8 million, respectively. The Utility concluded that the unrealized losses were other-than-temporary impairments and recorded a reduction to the nuclear decommissioning trusts assets and the corresponding regulatory liability for asset retirement costs. There were no individually material unrealized losses.

The following table provides a summary of 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, 2010				
Equity securities				
U.S.	**$ 509**	**$ 529**	**$ (2)**	**$ 1,036**
Non-U.S.	**180**	**170**	**(1)**	**349**
Debt securities				
U.S. government and agency securities	**571**	**55**	**(2)**	**624**
Municipal securities	**119**	**1**	**(1)**	**119**
Other fixed income securities	**65**	**1**	**–**	**66**
Total	**$ 1,444**	**$ 756**	**$ (6)**	**$ 2,194**
As of December 31, 2009				
Equity securities				
U.S.	$ 344	$ 425	$ (1)	$ 768
Non-U.S.	182	163	(1)	344
Debt securities				
U.S. government and agency securities	656	52	(4)	704
Municipal securities	89	1	–	90
Other fixed income securities	108	2	(2)	108
Total	$ 1,379	$ 643	$ (8)	$ 2,014

(1) Excludes taxes on appreciation of investment value.

The debt securities mature on the following schedule:

As of December 31, 2010	(in millions)
Less than 1 year	$ 37
1–5 years	349
5–10 years	215
More than 10 years	208
Total maturities of debt securities	$ 809

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

	Year Ended December 31,		
(in millions)	**2010**	2009	2008
Proceeds from sales and maturities of nuclear decommissioning trust investments	**$ 1,405**	$ 1,351	$ 1,635
Gross realized gains on sales of securities held as available-for-sale	**42**	27	30
Gross realized losses on sales of securities held as available-for-sale	**(11)**	(55)	(142)

NOTE 12: EMPLOYEE BENEFIT PLANS

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"), 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. PG&E Corporation and the Utility use a December 31 measurement date for all plans.

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.

CHANGE IN PLAN ASSETS, BENEFIT OBLIGATIONS, AND FUNDED STATUS

The following tables show the reconciliation of changes in plan assets, benefit obligations, and the plans' aggregate funded status for pension benefits and other benefits for PG&E Corporation during 2010 and 2009:

Pension Benefits

(in millions)	**2010**	2009
Change in plan assets:		
Fair value of plan assets at January 1	**$ 9,330**	$ 8,066
Actual return on plan assets	**1,235**	1,523
Company contributions	**162**	187
Benefits and expenses paid	**(477)**	(446)
Fair value of plan assets at December 31	**$ 10,250**	$ 9,330
Change in benefit obligation:		
Projected benefit obligation at January 1	**$ 10,766**	$ 9,767
Service cost for benefits earned	**253**	227
Interest cost	**645**	624
Actuarial loss	**856**	494
Plan amendments	**(1)**	71
Transitional costs	**4**	3
Benefits paid	**(452)**	(420)
Projected benefit obligation at December 31 (1)	**$ 12,071**	$ 10,766
Funded status:		
Current liability	**$ (5)**	$ (5)
Noncurrent liability	**(1,816)**	(1,431)
Accrued benefit cost at December 31	**$ (1,821)**	$ (1,436)

(1) PG&E Corporation's accumulated benefit obligation was $10,653 million and $9,527 million at December 31, 2010 and 2009, respectively.

Other Benefits

(in millions)	2010	2009
Change in plan assets:		
Fair value of plan assets at January 1	**$ 1,169**	$ 990
Actual return on plan assets	**147**	166
Company contributions	**94**	87
Plan participant contribution	**49**	42
Benefits and expenses paid	**(122)**	(116)
Fair value of plan assets at December 31	**$ 1,337**	$ 1,169
Change in benefit obligation:		
Benefit obligation at January 1	**$ 1,511**	$ 1,382
Service cost for benefits earned	**36**	30
Interest cost	**88**	87
Actuarial loss	**52**	72
Plan amendments	**128**	–
Transitional costs	**1**	1
Benefits paid	**(113)**	(106)
Federal subsidy on benefits paid	**3**	4
Plan participant contributions	**49**	41
Benefit obligation at December 31	**$ 1,755**	$ 1,511
Funded status:		
Noncurrent liability	**$ (418)**	$ (342)
Accrued benefit cost at December 31	**$ (418)**	$ (342)

There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

On February 16, 2010, the Utility amended its contributory postretirement medical plans for retirees to provide for additional employer contributions toward retiree premiums. The plan amendment was accounted for as a plan modification that required re-measurement of the accumulated benefit obligation, plan assets, and periodic benefit costs. The inputs and assumptions used in re-measurement did not change significantly from December 31, 2009 and did not have a material impact on the funded status of the plans. The re-measurement of the accumulated benefit obligation and plan assets resulted in an increase to other postretirement benefits and a decrease to other comprehensive income of $148 million. The impact to net periodic benefit cost was not material.

Components of Net Periodic Benefit Cost

Net periodic benefit cost as reflected in PG&E Corporation's Consolidated Statements of Income for 2010, 2009, and 2008 is as follows:

Pension Benefits

		December 31,	
(in millions)	2010	2009	2008
Service cost for benefits earned	**$ 279**	$ 259	$ 236
Interest cost	**645**	624	581
Expected return on plan assets	**(624)**	(579)	(696)
Amortization of prior service cost	**53**	53	47
Amortization of unrecognized loss	**44**	101	1
Net periodic benefit cost	**397**	458	169
Less: transfer to regulatory account [1]	**(233)**	(294)	(4)
Total	**$ 164**	$ 164	$ 165

(1) The Utility recorded $233 million, $295 million, and $4 million for the years ended December 31, 2010, 2009, and 2008, respectively, to a regulatory account as the amounts are probable of recovery from customers in future rates.

Other Benefits

	December 31,		
(in millions)	**2010**	2009	2008
Service cost for benefits earned	**$ 36**	$ 30	$ 29
Interest cost	**88**	87	81
Expected return on plan assets	**(74)**	(68)	(93)
Amortization of transition obligation	**26**	26	26
Amortization of prior service cost	**25**	16	16
Amortization of unrecognized loss (gain)	**3**	3	(15)
Net periodic benefit cost	**$ 104**	$ 94	$ 44

There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

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. (See Note 2 above.)

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 defined 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.

The estimated amounts that will be amortized into net periodic benefit cost for PG&E Corporation in 2011 are as follows:

Pension Benefits

(in millions)	
Unrecognized prior service cost	$ 35
Unrecognized net loss	48
Total	$ 83

Other Benefits

(in millions)	
Unrecognized prior service cost	$ 26
Unrecognized net loss	4
Unrecognized net transition obligation	26
Total	$ 56

There were no material differences between the estimated amounts that will be amortized into net period benefit costs for PG&E Corporation and the Utility.

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, 2010 and 2009 and reduced the net periodic cost for 2010 and 2009 by the following amounts:

(in millions)	2010	2009
Accumulated postretirement benefit obligation reduction	$ 72	$ 71
Net periodic benefit cost reduction	1	7

On March 30, 2010, federal health care legislation was signed eliminating the deduction for subsidy contributions after 2012. (See Note 9 above.)

There was no material difference between PG&E Corporation's and the Utility's Medicare Part D subsidy during 2010.

Valuation Assumptions

The following actuarial assumptions were used in determining the projected benefit obligations and the net periodic cost. The following weighted average year-end assumptions were used in determining the plans' projected benefit obligations and net benefit cost.

	Pension Benefits			Other Benefits		
	December 31,			December 31,		
	2010	2009	2008	**2010**	2009	2008
Discount rate	**5.42%**	5.97%	6.31%	**5.11–5.56%**	5.66–6.09%	5.85–6.33%
Average rate of future compensation increases	**5.00%**	5.00%	5.00%	**–**	–	–
Expected return on plan assets	**6.60%**	6.80%	7.30%	**5.20–6.60%**	5.80–6.90%	7.00–7.30%

The assumed health care cost trend rate as of December 31, 2010 is 8%, decreasing gradually to an ultimate trend rate in 2018 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	$ 83	$ (86)
Effect on service and interest cost	7	(7)

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 plan trusts, resulting in a weighted average rate of return on plan assets. Returns on fixed-income debt investments were projected based on real maturity and credit spreads added to a long-term inflation rate. Returns on equity investments were estimated based on estimates of dividend yield and real earnings growth added to a long-term inflation rate. For the pension plan, the assumed return of 6.6% compares to a ten-year actual return of 6.2%. The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of over approximately 600 Aa-grade non-callable bonds at December 31, 2010. 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 for 2009 was lower than the expected return due to the significant decline in equity market values that occurred in 2009. The actual return on plan assets in 2010 was in line with the expectations.

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, as amended ("ERISA"). 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, interest rate swaps, 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 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, 2011, 2010, and 2009 are as follows:

	Pension Benefits			Other Benefits		
	2011	**2010**	2009	2011	**2010**	2009
U.S. Equity	26%	**26%**	32%	28%	**26%**	37%
Non-U.S. Equity	14%	**14%**	18%	15%	**13%**	18%
Global Equity	5%	**5%**	5%	3%	**3%**	3%
Absolute Return	5%	**5%**	5%	4%	**3%**	3%
Fixed Income	50%	**50%**	40%	50%	**54%**	34%
Cash Equivalents	–%	**–%**	–%	–%	**1%**	5%
Total	100%	**100%**	100%	100%	**100%**	100%

FAIR VALUE MEASUREMENTS

The following tables present the fair value of plan assets for pension and other benefit plans by major asset category at December 31, 2010 and 2009.

	Fair Value Measurements as of December 31, 2010			
(in millions)	Level 1	Level 2	Level 3	Total
Pension Benefits:				
U.S. Equity	**$ 328**	**$ 2,482**	**$ –**	**$ 2,810**
Non-U.S. Equity	**356**	**1,111**	**–**	**1,467**
Global Equity	**177**	**360**	**–**	**537**
Absolute Return	**–**	**–**	**494**	**494**
Fixed Income:				
U.S. Government	**790**	**233**	**–**	**1,023**
Corporate	**6**	**2,724**	**549**	**3,279**
Other	**52**	**393**	**120**	**565**
Cash Equivalents	**20**	**–**	**–**	**20**
Total	**$ 1,729**	**$ 7,303**	**$ 1,163**	**$ 10,195**
Other Benefits:				
U.S. Equity	**$ 104**	**$ 230**	**$ –**	**$ 334**
Non-U.S. Equity	**118**	**80**	**–**	**198**
Global Equity	**18**	**29**	**–**	**47**
Absolute Return	**–**	**–**	**47**	**47**
Fixed Income:				
U.S. Government	**73**	**14**	**–**	**87**
Corporate	**8**	**457**	**129**	**594**
Other	**3**	**21**	**10**	**34**
Cash Equivalents	**13**	**–**	**–**	**13**
Total	**$ 337**	**$ 831**	**$ 186**	**$ 1,354**
Other Assets				**38**
Total Plan Assets at Fair Value				**$ 11,587**

(in millions)	Fair Value Measurements as of December 31, 2009 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

Equity Securities

The U.S., Non-U.S., and combined Global Equity categories include equity investments in common stock and commingled funds composed 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 composed 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. Commingled funds are categorized as Level 2 assets.

Absolute Return

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.

Fixed Income

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. government bonds that are valued based on quoted market prices or evaluated pricing data for similar securities adjusted for observable differences. These securities are categorized as Level 1 or Level 2 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. The fair value of corporate bonds is determined using recently executed transactions, market price quotations (where observable), and bond spreads or credit default swap spreads obtained from independent external parties such as vendors and brokers, adjusted for any basis difference between cash and derivative instruments. These securities are classified as Level 2 assets. Corporate fixed income also includes one commingled fund composed 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 primarily valued based on 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

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.

TRANSFERS BETWEEN LEVELS

PG&E Corporation and the Utility recognize any transfers between levels in the fair value hierarchy as of the end of the reporting period. There were no significant transfers between levels for the year ended December 31, 2010.

Level 3 Reconciliation

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 for the years ended December 31, 2010 and 2009:

(in millions)	Absolute Return	Corporate Fixed Income	Other Fixed Income	Total
Pension Benefits:				
Balance as of December 31, 2009	$ 340	$ 531	$ 190	$ 1,061
Actual return on plan assets:				
Relating to assets still held at the reporting date	44	52	5	101
Relating to assets sold during the period	5	5	5	15
Purchases, sales, and settlements	105	(39)	(80)	(14)
Transfers into (out of) Level 3	–	–	–	–
Balance as of December 31, 2010	**$ 494**	**$ 549**	**$ 120**	**$ 1,163**
Other Benefits:				
Balance as of December 31, 2009	$ 32	$ 124	$ 17	$ 173
Actual return on plan assets:				
Relating to assets still held at the reporting date	4	15	–	19
Relating to assets sold during the period	1	(2)	–	(1)
Purchases, sales, and settlements	10	(8)	(7)	(5)
Transfers into (out of) Level 3	–	–	–	–
Balance as of December 31, 2010	**$ 47**	**$ 129**	**$ 10**	**$ 186**

(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 $162 million to the pension benefit plans and $94 million to the other benefit plans in 2010. 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 2010. The Utility's pension benefits met all the funding requirements under ERISA. PG&E Corporation and the Utility expect to make total contributions of approximately $245 million and $58 million to the pension plan and other postretirement benefit plans, respectively, for 2011.

Benefits Payments

As of December 31, 2010, the estimated benefits expected to be paid in each of the next five fiscal years, and in aggregate for the five fiscal years thereafter for PG&E Corporation, are as follows:

(in millions)	Pension	Other
2011	$ 509	$ 114
2012	547	117
2013	586	122
2014	624	128
2015	663	133
2016–2020	3,869	725

There were no material differences between the estimated benefits expected to be paid for PG&E Corporation and the Utility for the years presented above.

DEFINED CONTRIBUTION BENEFIT PLANS

PG&E Corporation sponsors employee retirement savings plans, including a 401(k) defined contribution savings plan. 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)	
Year ended December 31,	
2010	$ 56
2009	52
2008	53

There were no material differences between the employer contribution expense for PG&E Corporation and the Utility for the years presented above.

NOTE 13: RESOLUTION OF REMAINING CHAPTER 11 DISPUTED CLAIMS

Various electricity suppliers filed claims in the Utility's proceeding under Chapter 11 seeking payment for energy supplied to the Utility's customers through the wholesale electricity markets operated by the CAISO and the California Power Exchange ("PX") between May 2000 and June 2001. These claims, which the Utility disputes, are being addressed in various FERC and judicial proceedings in which the State of California, the Utility, and other electricity purchasers are seeking refunds from electricity suppliers, including municipal and governmental entities, for overcharges incurred in the CAISO and the PX wholesale electricity markets between May 2000 and June 2001. At December 31, 2010 and December 31, 2009, the Utility held $512 million and $515 million in escrow, respectively, 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 refunded to customers.

The following table presents the changes in the remaining net disputed claims liability and interest accrued from December 31, 2009 to December 31, 2010:

(in millions)	
Balance at December 31, 2009	$ 946
Interest accrued	30
Less: supplier settlements	(42)
Balance at December 31, 2010	**$ 934**

At December 31, 2010, the Utility's net disputed claims liability was $934 million, consisting of $745 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 $683 million (classified on the Consolidated Balance Sheets within interest payable), partially offset by accounts receivable from the CAISO and the PX of $494 million (classified on the Consolidated Balance Sheets within accounts receivable – other).

Interest accrues on the net 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 and when such interest is paid.

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 14: 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)	**2010**	2009	2008
Utility revenues from:			
Administrative services provided to PG&E Corporation	**$ 7**	$ 5	$ 4
Utility expenses from:			
Administrative services received from PG&E Corporation	**$ 55**	$ 62	$ 122
Utility employee benefit due to PG&E Corporation	**27**	3	2

At December 31, 2010 and December 31, 2009, the Utility had a receivable of $89 million and $26 million, respectively, from PG&E Corporation included in accounts receivable – other and other noncurrent assets – other on the Utility's Consolidated Balance Sheets, and a payable of $16 million, respectively, to PG&E Corporation included in accounts payable – other on the Utility's Consolidated Balance Sheets.

NOTE 15: 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.

The table below shows the costs incurred for each type of third-party power purchase agreement at December 31, 2010:

	Payments		
(in millions)	**2010**	2009	2008
Qualifying facilities [1][2]	**$ 1,164**	$ 1,210	$ 1,724
Renewable energy contracts [1]	**573**	362	302
Other power purchase agreements [1]	**598**	643	2,036
Irrigation district and water agencies [1]	**59**	58	69

(1) 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.

(2) Payments include $321, $344, and $412 attributable to renewable energy contracts with qualifying facilities at December 31, 2010, 2009 and 2008, respectively.

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 with generation facilities that meet the statutory definition of a qualifying facility ("QF"). QFs include small power production facilities whose primary energy sources are co-generation facilities that produce combined heat and power ("CHP") and renewable generation facilities. 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.

As of December 31, 2010, the Utility had agreements with 226 QFs for approximately 3,700 megawatts ("MW") that are in operation. Agreements for approximately 3,400 MW expire at various dates between 2011 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 75 inoperative QFs. The total of approximately 3,700 MW consists of approximately 2,500 MW from cogeneration projects and approximately 1,200 MW from renewable sources. No single QF accounted for more than 5% of the Utility's 2010, 2009, or 2008 electricity sources.

Renewable Energy Power Purchase Agreements—The Utility has entered into various contracts to purchase renewable energy to help the Utility meet the current renewable portfolio standard ("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 developed timely. No single supplier accounted for more than 5% of the Utility's 2010, 2009, or 2008 electricity sources.

Other Power 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.

Irrigation District and Water Agency Power Purchase Agreements – 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 2011 to 2031. Irrigation districts and water agencies consist of small and large hydro plants. No single irrigation district or water agency accounted for more than 5% of the Utility's 2010, 2009, or 2008 electricity sources.

At December 31, 2010, the undiscounted future expected power purchase agreement payments were as follows:

	Qualifying Facility		Renewable (Other than QF)		Irrigation District & Water Agency		Other		
(in millions)	Energy	Capacity	Energy	Capacity	Operations & Maintenance	Debt Service	Energy	Capacity	Total Payments
2011	$ 720	$ 366	$ 796	$ 8	$ 59	$ 21	$ 3	$ 691	$ 2,664
2012	545	321	944	9	45	21	3	684	2,572
2013	542	312	1,261	9	28	15	3	822	2,992
2014	548	301	1,647	–	13	12	1	605	3,127
2015	509	259	1,942	–	11	11	–	583	3,315
Thereafter	3,129	1,263	40,882	5	27	16	–	4,227	49,549
Total	$ 5,993	$ 2,822	$ 47,472	$ 31	$ 183	$ 96	$ 10	$ 7,612	$ 64,219

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)	
2011	$ 50
2012	50
2013	50
2014	42
2015	38
Thereafter	124
Total fixed capacity payments	354
Less: amount representing interest	72
Present value of fixed capacity payments	$ 282

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 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.

The present value of the fixed capacity payments due under these contracts is recorded on PG&E Corporation's and the Utility's Consolidated Balance Sheets. At December 31, 2010 and December 31, 2009, current liabilities – other included $34 million and $32 million, respectively, and noncurrent liabilities – other included $248 million and $282 million, respectively. The corresponding assets at December 31, 2010 and December 31, 2009 of $282 million and $314 million including accumulated amortization of $126 million and $94 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 quantities of the Utility's portfolio of natural gas procurement contracts can fluctuate based on market conditions. The Utility also contracts for natural gas transportation 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 northern California in order to better meet core customers' winter peak loads. At December 31, 2010, the Utility's undiscounted obligations for natural gas purchases, natural gas transportation services, and natural gas storage were as follows:

(in millions)	
2011	$ 710
2012	273
2013	191
2014	170
2015	161
Thereafter	1,128
Total (1)	$ 2,633

(1) Amounts above include firm transportation contracts for the Ruby Pipeline (a 1.5 billion cubic feet per day ("bcf/d") pipeline that is currently under construction and expected to become operational in the summer of 2011; and the Utility has contracted for a capacity of approximately 0.4 bcf/d).

Payments for natural gas purchases, natural gas transportation services, and natural gas storage amounted to $1.6 billion in 2010, $1.4 billion in 2009, and $2.7 billion in 2008.

Nuclear Fuel Agreements

The Utility has entered into several purchase agreements for nuclear fuel. These agreements have terms ranging from 1 to 14 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 2016, while contracts for fuel fabrication services provide for 100% coverage of reactor requirements through 2017. 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. Price increases in the uranium and enrichment service markets are providing upward pressure on nuclear fuel costs starting in 2011.

At December 31, 2010, the undiscounted obligations under nuclear fuel agreements were as follows:

(in millions)	
2011	$ 84
2012	69
2013	105
2014	132
2015	191
Thereafter	1,057
Total	$ 1,638

Payments for nuclear fuel amounted to $144 million in 2010, $141 million in 2009, and $157 million in 2008.

Other Commitments and Operating Leases

The Utility has other commitments relating to operating leases. At December 31, 2010, the future minimum payments related to other commitments were as follows:

(in millions)	
2011	$ 25
2012	22
2013	19
2014	14
2015	11
Thereafter	73
Total	$ 164

Payments for other commitments and operating leases amounted to $25 million in 2010, $22 million in 2009, and $41 million in 2008. PG&E Corporation and the Utility had operating leases on office facilities expiring at various dates from 2011 to 2020. Certain leases on office facilities contain escalation clauses requiring annual increases in rent ranging from 1% to 4%. 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, 2010, the Utility was committed to spending approximately $236 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 communications utilities involved. The Utility expects to spend approximately $42 million to $60 million each year in connection with these projects. Consistent with past practice, the Utility expects that these capital expenditures will be included in rate base as each individual project is completed and recoverable in rates charged to customers.

CONTINGENCIES

PG&E CORPORATION

PG&E Corporation retains a guarantee related to certain 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' 2006 through 2008 energy efficiency programs. On December 16, 2010, the CPUC awarded the Utility a final true-up payment award of $29.1 million for the 2006 through 2008 energy efficiency program cycle. Including this award, the Utility has earned incentive revenues totaling $104 million through December 31, 2010 based on the energy savings achieved through implementation of the Utility's energy efficiency programs during the 2006 through 2008 program cycle. The CPUC has directed the utilities to file their applications for incentive awards for 2009 energy efficiency program performance by June 30, 2011 to enable the CPUC to issue a final decision by the end of 2011.

On November 15, 2010, a proposed decision was issued that, if adopted by the CPUC, would modify the incentive mechanism that would apply to the 2010 through 2012 program cycle. Among other changes, the proposed modification would limit the total amount of the incentive award or penalty that could be awarded to, or imposed on, all the investor-owned utilities to $189 million. If the proposed decision is adopted, the Utility's opportunity to earn incentive revenues would be limited compared to the mechanism that was in place for the 2006 through 2008 program cycle.

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 Power Plant ("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 at Diablo Canyon 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. The Ninth Circuit heard oral arguments on November 4, 2010. The Utility expects a decision from the Ninth Circuit in 2011.

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 sought to recover $92 million of costs that it incurred through 2004. After several years of litigation, on March 30, 2010, the U.S. Court of Federal Claims awarded the Utility $89 million. The DOE filed an appeal of this decision on May 28, 2010. On August 3, 2010, the Utility filed two complaints against the DOE in the U.S. Court of Federal Claims seeking to recover all costs incurred since 2005 to build on-site storage facilities. The Utility estimates that it has incurred costs of at least $205 million since 2005. 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 $3.2 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 $42 million per one-year policy term.

NEIL also provides coverage for damages caused by acts of terrorism at nuclear power plants. If one or more acts of terrorism cause damages 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 NEIL's policy limit of $3.2 billion within a 12-month period plus any additional amounts recovered by NEIL for these losses from reinsurance. Certain acts of terrorism may be "certified" by the Secretary of the Treasury. For damages caused by certified acts of terrorism, NEIL can obtain compensation from the federal government and will provide up to its full policy limit of $3.2 billion for each insured loss caused by these certified acts of terrorism. The $3.2 billion amount would not be shared as is described above for damages caused by acts of terrorism that have not been certified.

Under the Price-Anderson Act, public liability claims that arise from nuclear incidents that occur at Diablo Canyon, and that occur during the transportation of material to and from Diablo Canyon are limited to $12.6 billion. As required by the Price-Anderson Act, the Utility purchased the maximum available public liability insurance of $375 million for Diablo Canyon. The balance of the $12.6 billion of liability protection is provided under a loss-sharing program among utilities owning nuclear reactors. The Utility may be assessed up to $235 million per nuclear incident under this program, with payments in each year limited to a maximum of $35 million per incident. Both the maximum assessment 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.

The Price-Anderson Act does not apply to public liability claims that arise from nuclear incidents that occur during shipping of nuclear material from the nuclear fuel enricher to a fuel fabricator or that occur at the fuel fabricator's facility. Such claims are covered by nuclear liability policies purchased by the enricher and the fuel fabricator as well as by separate supplier's and transporter's ("S&T") insurance policies. The Utility has an S&T policy that provides coverage for claims arising from some of these incidents up to a maximum of $375 million per incident. The Utility could incur losses that are either not covered by insurance or exceed the amount of insurance available.

In addition, the Utility has $53 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 million of liability insurance.

Legal Matters

PG&E Corporation and the Utility are subject to various laws and regulations and, in the normal course of business, PG&E Corporation and the Utility are named as parties in a number of claims and lawsuits. In addition, the Utility can incur penalties for failure to comply with federal, state, or local laws and regulations.

PG&E Corporation and the Utility record 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. PG&E Corporation and the Utility evaluate the range of reasonably estimated costs and record a liability based on the lower end of the range, unless an amount within the range is a better estimate than any other amount. 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 (other than third-party liability claims related to the San Bruno accident, as discussed below) totaled $55 million at December 31, 2010 and $57 million at December 31, 2009 and is included in PG&E Corporation's and the Utility's current liabilities – other in the Consolidated Balance Sheets. Except as discussed below, PG&E Corporation and the Utility do not believe that losses associated with legal matters would have a material adverse impact on their financial condition, results of operations, or cash flows after consideration of the accrued liability at December 31, 2010.

Explosion and Fires in San Bruno, California

On September 9, 2010, an underground 30-inch natural gas transmission pipeline (line 132) owned and operated by the Utility ruptured in a residential area located in the City of San Bruno, California ("San Bruno accident"). The ensuing explosion and fire resulted in the deaths of eight people, injuries to numerous individuals, and extensive property damage. Both the NTSB and the CPUC have begun investigations of the San Bruno accident, but they have not yet determined the cause of the pipeline rupture. The NTSB has issued several public statements regarding the investigation and a metallurgy report, all of which are available on the NTSB's website. The NTSB will hold fact-finding hearings in Washington, D.C. on March 1, 2011 through March 3, 2011 and has stated that it intends to release a total of six factual reports about the San Bruno accident before the hearings begin based on the following topics: metallurgy, operations, human performance, survival factors, fire scene, and meteorology. It is expected that these reports will be made publicly available on the NTSB's website as each report is released.

As part of the CPUC's investigation, the CPUC's staff will examine the safety of the Utility's natural gas transmission pipelines in its northern and central California service territory. The CPUC staff reviewed information about the Utility's planned and unplanned pressurization events where the pressure has risen above the maximum available operating pressure ("MAOP") in several of the Utility's gas transmission lines. On February 2, 2011, the CPUC ordered the Utility to reduce operating pressure twenty percent below the MAOP on certain of its gas transmission pipelines, and also ordered the Utility to reduce operating pressure on other transmission lines that meet certain criteria. The Utility has complied with the CPUC's order and also has reported to the CPUC that the Utility has identified a number of instances where it had either exceeded MAOP by more than ten percent or had raised the pressure to maintain operational flexibility, including several instances in which the highest pressure reading exceeded MAOP by a few pounds, but not more than ten percent. The CPUC also has appointed an independent review panel to gather and review facts, make a technical assessment of the San Bruno accident and its root cause, and make recommendations for action by the CPUC to ensure such an accident is not repeated. The report of the independent review panel is expected in the second quarter of 2011.

Several parties have requested that the CPUC institute a formal CPUC investigation into the San Bruno accident. The Utility has filed a response stating that it welcomes the CPUC's investigation. The CPUC may consider this request at its meeting to be held on February 24, 2011. If the CPUC institutes a formal investigation, the CPUC may impose penalties if it determines that the Utility violated any laws, rules, regulations, or orders pertaining to the operations and maintenance of its natural gas system. The CPUC is authorized to assess penalties of up to $20,000 per day, per violation. PG&E Corporation and the Utility anticipate that the CPUC will institute one or more formal investigations regarding these matters. PG&E Corporation and the Utility are unable to estimate a potential loss or range of loss associated with penalties that may be imposed by the CPUC in connection with the San Bruno accident.

In addition to these investigations, as of February 8, 2011, 59 lawsuits on behalf of approximately 177 plaintiffs, including two class action lawsuits, have been filed against PG&E Corporation and the Utility in San Mateo County Superior Courts. In addition, five lawsuits on behalf of 11 plaintiffs have been filed by residents of San Bruno in the San Francisco County Superior Court against PG&E Corporation and the Utility. These lawsuits seek compensation for personal injury and property damage and seek other relief. The class action lawsuits allege causes of action for strict liability, negligence, public nuisance, private nuisance, and declaratory relief. Several other residents also have submitted damage claims to the Utility. The Utility has filed a petition on behalf of PG&E Corporation and the Utility to coordinate these lawsuits in San Mateo County Superior Court. In its statement in support of coordination, the Utility has stated that it is prepared to enter into early mediation in an effort to resolve claims with those plaintiffs willing to do so. A hearing is scheduled for February 24, 2011.

The Utility recorded a provision of $220 million in 2010 for estimated third-party claims related to the San Bruno accident, including personal injury and property damage claims, damage to infrastructure, and other damage claims. The Utility currently estimates that it may incur as much as $400 million for third-party claims. This estimate may change depending on the final determination of the causes for the pipeline rupture and responsibility for the personal injuries and property damages and the number and nature of third-party claims. As more information becomes known, including information resulting from the NTSB and CPUC investigations, management's estimates and assumptions regarding the amount of third-party liability incurred in connection with the San Bruno accident may change. It is possible that a change in estimate could have a material adverse impact on PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows.

The Utility maintains liability insurance for damages in the approximate amount of $992 million in excess of a $10 million deductible. Although PG&E Corporation and the Utility currently consider it likely that most of the costs the Utility incurs for third-party claims relating to the San Bruno accident will ultimately be recovered through this insurance, no amounts for insurance recoveries have been recorded as of December 31, 2010. PG&E Corporation and the Utility are unable to predict the amount and timing of insurance recoveries.

CPUC Investigation of the December 24, 2008 Natural Gas Explosion in Rancho Cordova, California

On November 19, 2010, the CPUC began an investigation of the natural gas explosion and fire that occurred on December 24, 2008 in a house in Rancho Cordova, California ("Rancho Cordova accident"). The explosion resulted in one death, injuries to several people, and property damage. The CPUC's Consumer Protection and

Safety Division ("CPSD") and the NTSB investigated the accident. The NTSB issued its investigative report in May 2010, and the CPSD submitted its report to the CPUC in November 2010. The NTSB determined that the probable cause of the release, ignition, and explosion of natural gas was use of a section of unmarked and out-of-specification polyethylene pipe with inadequate wall thickness that allowed gas to leak from the mechanical coupling that had been installed on September 21, 2006. The NTSB stated that the delayed response by the Utility's employees was a contributing factor. Based on the CPSD's and the NTSB's investigative findings, the CPSD requested the CPUC to open a formal investigation and recommended that the CPUC impose unspecified fines and penalties on the Utility.

In its order instituting the investigation, the CPUC stated that it will determine whether the Utility violated any law, regulation, CPUC general orders or decisions, or other rules or requirement applicable to the Utility's natural gas service and facilities, and/or engaged in unreasonable and/or imprudent practices in connection with the Rancho Cordova accident. The CPUC also stated that it intends to ascertain whether any management policies and practices contributed to violations of law and the Rancho Cordova accident.

The CPUC ordered the Utility to provide extensive information, from as far back as January 1, 2000, about its practices and procedures at issue. The Utility's report, due on February 17, 2011, agrees with the NTSB's conclusions about the probable cause of the accident and explains what process improvements the Utility has made to prevent a similar accident in the future. The CPUC has scheduled a pre-hearing conference for March 1, 2011 to establish a schedule for the proceeding, including the date of an evidentiary hearing. PG&E Corporation and the Utility believe that the CPUC is likely to impose penalties on the Utility in connection with the Rancho Cordova accident.

PG&E Corporation and the Utility are unable to predict the ultimate outcome of the investigations of the San Bruno and Rancho Cordova accidents. The CPUC is authorized to impose penalties of up to $20,000 per day, per violation. If the CPUC imposed a material amount of penalties on the Utility, there would be a material adverse impact on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

ENVIRONMENTAL MATTERS

The Utility has been, and may be, required to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party under federal and state environmental laws. These sites include former manufactured gas plant ("MGP") sites, power plant sites, gas gathering sites, sites where natural gas compressor stations are located, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous substances. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if it did not deposit those substances on the site.

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 an amount within the range is a better estimate than any other amount. Amounts recorded are not discounted to their present value.

The Utility had an undiscounted and gross environmental remediation liability of $612 million at December 31, 2010 and $586 million at December 31, 2009. The following table presents the changes in the environmental remediation liability from December 31, 2009:

(in millions)	
Balance at December 31, 2009	$ 586
Additional remediation costs accrued:	
Transfer to regulatory account for recovery	112
Amounts not recoverable from customers	29
Less: Payments	(115)
Balance at December 31, 2010	**$ 612**

The $612 million accrued at December 31, 2010 consists of the following:

- $45 million for remediation at the Utility's natural gas compressor site located near Hinkley, California;
- $171 for remediation at the Utility's natural gas compressor site located on the California border, near Topock, Arizona;
- $85 million related to remediation at divested generation facilities;
- $110 million related to remediation costs for the Utility's generation and other facilities and for third-party disposal sites;
- $139 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

$62 million related to remediation costs for fossil decommissioning sites.

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 former MGPs located throughout the Utility's service territory. Of the forty one MGP sites owned or operated by the Utility, forty have been or are in the process of being investigated and/or remediated, and the Utility is developing a strategy to investigate and remediate the last site.

Of the $612 million environmental remediation liability, the Utility expects to recover $316 million through the CPUC-approved ratemaking mechanism that authorizes the Utility to recover 90% of hazardous waste remediation costs without a reasonableness review (excluding any remediation associated with the Hinkley natural gas compressor site) and $131 million through the ratemaking mechanism that authorizes the Utility to recover 100% of remediation costs for decommissioning fossil-fueled sites and certain of the Utility's transmission stations (excluding any remediation associated with divested generation facilities). 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 $1.2 billion if the extent of contamination or necessary remediation is greater than anticipated or if the other potentially responsible parties are not financially able to contribute to these costs, and could increase further if the Utility chooses to remediate beyond regulatory requirements.

QUARTERLY CONSOLIDATED FINANCIAL DATA (UNAUDITED)

	Quarter ended			
(in millions, except per share amounts)	December 31	September 30	June 30	March 31
2010				
PG&E Corporation				
Operating revenues	**$ 3,621**	**$ 3,513**	**$ 3,232**	**$ 3,475**
Operating income	**492**	**503**	**695**	**618**
Net income	**254**	**261**	**337**	**261**
Income available for common shareholders	**250**	**258**	**333**	**258**
Net earnings per common share, basic	**0.63**	**0.66**	**0.88**	**0.69**
Net earnings per common share, diluted	**0.63**	**0.66**	**0.86**	**0.67**
Common stock price per share:				
High	**48.63**	**48.34**	**45.00**	**45.63**
Low	**45.38**	**40.52**	**34.95**	**40.58**
Utility				
Operating revenues	**$ 3,620**	**$ 3,513**	**$ 3,232**	**$ 3,475**
Operating income	**494**	**505**	**696**	**619**
Net income	**253**	**265**	**339**	**264**
Income available for common stock	**249**	**262**	**335**	**261**
2009				
PG&E Corporation				
Operating revenues	$ 3,539	$ 3,235	$ 3,194	$ 3,431
Operating income	523	607	656	513
Net income	277	321	392	244
Income available for common shareholders	273	318	388	241
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 stock	263	350	387	236

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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, 2010, 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, 2010.

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, 2010 and 2009; 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, 2010. 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, 2010, 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, 2010 and 2009, 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, 2010. We also have audited the Company's and the Utility's internal control over financial reporting as of December 31, 2010, 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, 2010 and 2009, and the respective results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, 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, 2010, 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 17, 2011
San Francisco, California

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.

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1 C. Lee Cox is the non-executive Chairman of the Board of Pacific Gas and Electric Company, as well as the lead director of PG&E Corporation and 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

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

BRIAN A. C. STEEL
Vice President, Corporate Development

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

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

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

EDWARD T. BEDWELL
Vice President, Government Relations

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

M. KIRK JOHNSON
Vice President, Gas Engineering and Operations, Continuous Improvement Initiatives

MARK S. JOHNSON
Vice President, Electric Transmission Planning and Engineering

GREGORY K. KIRALY
Vice President, SmartMeter™ Operations

ROY M. KUGA
Vice President, Energy Supply Management

RANDAL S. LIVINGSTON
Vice President, Gas Transmission Programs

JANET C. LODUCA
Vice President, Corporate Relations

STEVEN E. MALNIGHT
Vice President, Integrated Demand Side Management

PLACIDO J. MARTINEZ
Vice President, Electric Distribution Planning and Engineering

DINYAR B. MISTRY
Vice President and Controller

KENNETH J. PETERS
Vice President, Engineering Services, Diablo Canyon Power Plant

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

ANDREW K. WILLIAMS
Vice President, Human Resources

ALBERT F. TORRES
Vice President, Customer Operations

JANE K. YURA
Vice President, Gas Engineering and Operations

SHAREHOLDER INFORMATION

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 10, 2011, there were 75,862 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 contact 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 Service Representatives are available Monday through Friday from 9:00 a.m. EST to 7:00 p.m. EST)
Website: www.bnymellon.com/shareowner/equityaccess

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 contact 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 market.

Issue	Newpaper 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

2011 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 stock 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 you 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 11, 2011

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 to obtain 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, 2010, which has been filed with the Securities and Exchange Commission, please send a written request to, or call, the Corporate Secretary's Office at:

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

You may also view the Form 10-K, and all other reports submitted by PG&E Corporation and Pacific Gas and Electric Company to the Securities and Exchange Commission on our website at: www.pgecorp.com/investors/financial_reports/.

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