Pacific Gas and Electric Company®

Donna Jacobs
Vice President
Nuclear Services

Diablo Canyon Power Plant
P. O. Box 56
Avila Beach, CA 93424

805.545.4600
Fax: 805.545.4234

April 26, 2006

PG&E Letter DCL-06-057
PG&E Letter HBL-06-013

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Docket No. 50-133, OP-DPR-7
Humboldt Bay Power Plant Unit 3
Pacific Gas and Electric (PG&E) Corporation 2005 Annual Report

Dear Commissioners and Staff:

Pursuant to 10 CFR 50.71(b) and 10 CFR 140.15(b)(1), enclosed is one hard copy of the PG&E Corporation 2005 Annual Report. Internet downloading, viewing, or copies of the PG&E Corporation 2005 Annual Report are available at:

http://www.pgecorp.com/investors/pdfs/2005AnnualReport.pdf

Sincerely,

Donna Jacobs

ddm
Enclosure
cc/enc: Ira P. Dinitz
John B. Hickman
cc: Marna N. Colcun
Terry W. Jackson, NRC Senior Resident Inspector
Bruce S. Mallett, NRC Region IV
David Sokolsky, HBPP Licensing
Alan B. Wang, NRR Project Manager
Diablo Distribution
PG Fossil Gen HBPP Humboldt Distribution

NMSS01

Enclosure
PG&E Letter DCL-06-057
PG&E Letter HBL-06-013

PG&E Corporation 2005 Annual Report

PG&E Corporation
Annual Report 2005

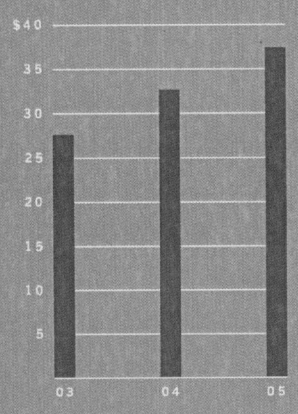
Today, we are taking a fresh look at PG&E through the eyes of our customers.

HOW WE PERFORMED IN 2005:

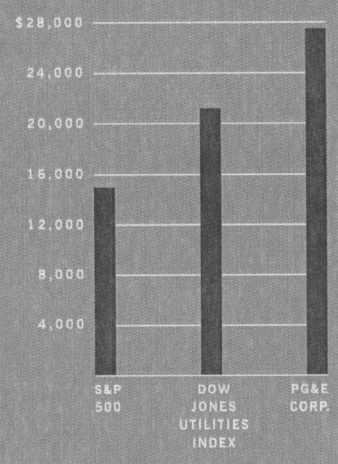
- We grew year-over-year earnings from operations by 10 percent to $2.34 per share.*
- Total return for PG&E Corporation shareholders was 15.3 percent.
- Our stock price grew from $33.28 at the end of 2004 to $37.12 at the end of 2005.
- PG&E Corporation once again began paying shareholders a quarterly common stock dividend, at the initial annual level of $1.20 per share. By the end of the year, we raised the annual dividend by 10 percent to $1.32 per share.
- We repurchased approximately $2.2 billion of PG&E Corporation stock.

TABLE OF CONTENTS

PG&E CORPORATION STOCK PERFORMANCE
(Year-end closing stock price.)



GROWTH OF A $10,000 INVESTMENT VERSUS OTHER INDICES
(Dec. 31, 2002 – Dec. 31, 2005)



*Earnings from operations is not a substitute for consolidated net income reported under generally accepted accounting principles (GAAP). We present "earnings from operations" in order to provide a measure that allows investors to compare our underlying financial performance from one period to another, exclusive of items that management believes do not reflect the normal course of operations. See the "Financial Highlights" table on page 31 for a reconciliation of earnings from operations with GAAP consolidated net income.

DEAR STAKEHOLDERS:

In 2005, PG&E celebrated 100 years of providing gas and electricity to Californians. At the start of our second century, our new focus and direction may best be signaled by this: PG&E's 2005 annual report to shareholders – our 100th – is the first ever to picture a customer on its cover.

Today, we are taking a fresh look at PG&E through the eyes of our customers. We are reflecting on our strengths and weaknesses with unprecedented rigor and candor. Most importantly, we are translating these insights and perspectives into substantial changes in the way we operate and deliver service.

We refer to this effort and everything it entails as "Transformation." Our decision to embark on this path is driven by a conviction that it is essential to our future.

PG&E's success going forward will be defined by our relationship with the customer more than any other aspect of our business.

Genuinely instilling this view as the driving force in our business – and believe me, we are doing exactly that – will be no small challenge. Over the years, utilities have become well schooled at seeing their business predominantly through the eyes of their regulators, whose power to say "yes" or "no" looms large in any significant management decision.

To guard against any misunderstanding, let me say clearly that, as a survivor of California's energy crisis, we will be the first to defend the importance of good regulation. We also have said that we see PG&E's future growth and opportunities remaining squarely within the regulated arena.

But we also will be the first to acknowledge that decades in this environment have made companies in our industry more adept at managing the business for the regulator than for the customer. Stated plainly, at some point the regulator became the customer, and the customer became the "ratepayer."

As a model for success going forward, this is every bit as broken as it sounds. We are convinced that the combined pressures of industry consolidation and rising customer expectations will make it impossible for PG&E and other utilities to survive, much less succeed, without restoring the customer as the focal point for our business.

Companies in competitive industries live and die by the maxim that if they don't take care of their customers, someone else will. In an industry where the barriers to consolidation are coming down, smart utilities will adopt the same view.

We also have to come to terms with the fact that competitive companies in other businesses are setting extraordinary standards for service. As the gap between their service and ours widens, customers will demand that utility companies elevate their performance to the same standards.

If we are going to succeed, we have to learn how to adapt our business processes and shape our culture to deliver the same customer experience. We have to take the same disciplined approach to understanding our customers and their needs. And we have to make this a fundamental, ongoing part of the way we do business. This is what Transformation is all about.

"PG&E's success going forward will be defined by our relationship with the customer more than any other aspect of our business."

I am confident that success in meeting these challenges will increasingly divide winners from losers in our business, just as it does in others. Make no mistake, PG&E is determined to be one of the winners.

Our vision is to become the leading utility in the United States, by delighting our 15 million customers, energizing our 20,000 employees and rewarding our shareholders.

This year's letter gives you an overview of what we did in 2005 – and plan to do in 2006 – to get us to that position.

WE DELIVERED HEALTHY FINANCIAL RESULTS.

PG&E's financial performance continues to drive competitive returns and generate the cash flows that enable us to put resources back into the business for the benefit of our customers and shareholders.

In 2005, PG&E once again began paying shareholders a quarterly common stock dividend. We set the annual dividend target initially at $1.20 per share. By the end of 2005, it was raised by 10 percent to $1.32 per share.

This accomplishment, along with the repurchase of more than $2 billion of stock, marked the successful completion of our strategy to fully restore PG&E's financial health in the wake of the energy crisis.

The market rewarded our shareholders accordingly, with a stock price that rose to levels at or near all-time highs. Our total return to shareholders – stock price growth plus common stock dividends – was 15.3 percent in 2005.

Underpinning PG&E's stock performance were strong earnings. Total net income reported in accordance with generally accepted accounting principles (GAAP) was $917 million, or $2.37 per share for the year. On a non-GAAP earnings from operations basis, which excludes items considered by management to be non-operating, earnings per share for 2005 grew by 10 percent compared with 2004 to $2.34. The Financial Highlights table on page 31 reconciles GAAP total net income with non-GAAP earnings from operations.

We expect to continue growing earnings at a rate that makes PG&E an attractive investment.

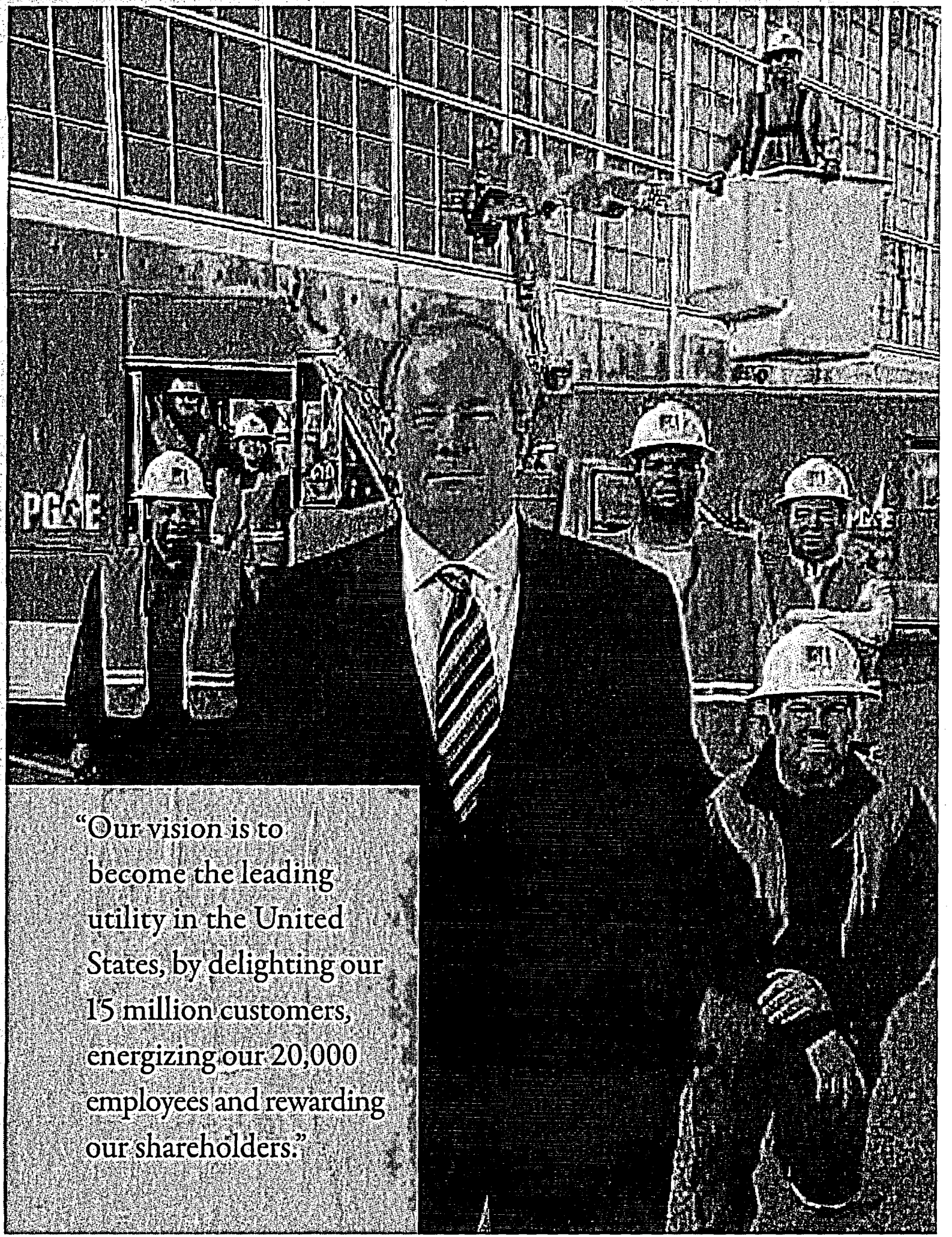
Recently, we set a target to grow earnings per share at an average rate of 7.5 percent annually for 2006 through 2010. The target reflects the positive impact of share repurchases and our substantial annual capital investment forecast. These investments in our system are expected to average at least $2.5 billion per year for 2006 through 2010, providing shareholders the opportunity to earn a return on a growing rate base.

These investments are also important to better serve our customers. Among other benefits, they will allow us to safeguard reliability by upgrading and replacing aging equipment, deploy new technology like SmartMeters and expand the capacity of the grid to support economic growth.

WE CONTINUED PLANNING FOR CALIFORNIA'S ENERGY FUTURE.

Over the past 30 years, PG&E's success in promoting energy efficiency and conservation has helped keep California's per capita electricity use essentially flat – a remarkable achievement compared with the rest of the United States, where that same measure has increased 50 percent.

Even as we continue these programs, however, California's energy needs are growing with its population and economy. In our service area, customers will need up to 2,200 megawatts of additional electric generation between 2008 and 2010.



"Our vision is to become the leading utility in the United States, by delighting our 15 million customers, energizing our 20,000 employees and rewarding our shareholders."

Making sure those resources are developed is a top priority in the year ahead. We began the process in 2005, and in early 2006 we expect to sign contracts that will result in new power plants being built to meet our customers' needs.

PG&E's plans also include acquiring and completing a partially built plant in the San Francisco Bay Area. If approved, this transaction will be a win for our customers and a solid investment for shareholders. The Contra Costa 8 facility would generate enough power for roughly 400,000 homes. We hope to have it built and on-line by 2008.

PG&E also continues to invest in critical electric transmission projects – the fastest growing part of our business. For example, we are building a major new line that will bring enough additional power into San Francisco for about 300,000 homes. In total, we plan to invest $1.8 billion in the system from 2006 through 2010 so we can accommodate growth, relieve grid congestion and ultimately boost reliability for our customers.

Significant projects now under way also include efforts to explore the feasibility of new natural gas pipelines and electric transmission lines that could provide our customers with access to low-cost energy sources in the Pacific Northwest.

Another important part of PG&E's focus on California's energy future is our commitment to the environment and clean energy, including giving priority to energy efficiency efforts and renewable energy sources before adding conventional resources to meet customers' needs.

In 2005, we signed several power contracts to increase the amount of our supply that comes from renewable energy sources. We plan to do so again in 2006. Currently, about 30 percent of the power we supply to our customers comes from renewable sources – 18 percent from large hydroelectric facilities and 12 percent from sources that qualify under California's renewable power requirement, like small hydro and wind. This represents one of the highest volumes of any investor-owned utility in the United States. When our nuclear operations are factored in, about half of our customer load is served from generating resources that emit no carbon dioxide.

PG&E also has the largest distributed solar energy program in the country. Through financial incentives, we have helped customers install more than 230 solar projects generating enough power for more than 20,000 homes. We connected our 10,000th solar customer to the grid in early 2006 – more than any other domestic utility. This year, we will also double the size of our Solar Schools Program, providing funding for solar electric systems in another 30 schools in underserved communities.

WE BEGAN CHANGING THE WAY WE OPERATE.

In 2005, PG&E conducted millions of electric and gas meter reads – every one of them manually. Starting in 2006, we are installing technology that will allow us to do this work remotely using SmartMeters that can send data back to PG&E on a continuous basis.

This single change in the way we operate will have far-reaching impacts. It will eliminate the need to estimate bills when a locked gate or a dog prevents us from accessing a meter. It will speed up our response to power outages by allowing us to electronically pinpoint the location and scope of an outage, something we cannot do today. It also will give us the option to offer customers a new way to save money, by signing up for pricing that varies depending on the time of day.

We plan to invest $1.4 billion of capital over the next five years to install nearly 10 million SmartMeters at homes and businesses throughout our service area.

SmartMeters are one of the most vivid examples of the kinds of changes we are implementing as part of Transformation. Others are less dramatic but just as important.

For example, last year we centralized and standardized the design work necessary to connect gas and electric service for new subdivisions of 20 or more homes. Consistent designs and faster schedules are now enabling us to improve the service we are providing to housing developers, who depend on us as a critical partner.

We also took steps to scale back the amount of office work our 300 front-line supervisors have to contend with, so they

can spend more time in the field working with their teams to focus on customer satisfaction, productivity and safety. Previously, they were spending about four hours a week in the field; now they are out with their teams about four hours a day. These are the benefits of just a few of about 20 different Transformation initiatives launched last year.

"Collectively, the impacts of Transformation will affect everything from how we connect new customers to the way we buy supplies and deliver them to a job site."

The scope of this effort stretches from one end of the business to the other. It encompasses everything from streamlining work-flows and restructuring parts of the organization, to using new technologies. Collectively, the impacts will affect everything from how we connect new customers to the way we buy supplies and deliver them to a job site.

This effort will extend over the next few years. Confident in our progress during 2005, we are accelerating our plan for 2006. By the end of this year, approximately 25 additional initiatives will be fully or partially implemented.

Importantly, the performance measures we are aiming to move have been explicitly defined. Some examples include the number and average duration of outages, how quickly we answer customer calls, and how we stack up against others in the J.D. Power customer satisfaction survey.

We are tracking our progress in these areas on a continuous basis because they give us the clearest picture of exactly how we are doing for the customer. We also are making this report card available for all of our employees to see, because this focus must be understood and owned by everyone at PG&E. To reinforce that message, we have also tied part of our compensation program directly to success in hitting our targets.

Additionally, we have proposed to the California Public Utilities Commission that customers and shareholders both have opportunities to share in the financial benefits we hope to achieve through Transformation.

WE SET OUT TO RESHAPE OUR CULTURE.

I personally heard from and spoke with thousands of PG&E employees last year. It was plain to me that every one of them is dedicated to doing great work for our customers.

But it was also evident that many felt that elements of our culture made it a challenge to follow through on their commitment.

When an employee doesn't feel empowered to speak up to a supervisor about a problem, or when one group can't get support from another team because their managers have different priorities, we can't expect to be providing top-tier service.

We could implement a thousand different cutting-edge Transformation projects, but they'll be built on sand unless we have the cultural foundation to support what we are working to achieve.

We worked intensively last year to begin building this foundation. This started at the senior-most level of the company, because we believe culture flows from the top.

How should our culture look in order to succeed?

It should encourage dialogue and listening between leadership and the field. It should be free of silos – structural or attitudinal – that keep groups within the company from working as one team. It should balk at bureaucracy. Reward initiative. Foster accountability. Challenge the status quo. Drive alignment around common goals.

One of our first steps has been to articulate a common set of values to guide our behavior and priorities at every level and in every part of the company. Here they are:

- We act with integrity and communicate honestly and openly.
- We are passionate about meeting our customers' needs and delivering for our shareholders.

- We are accountable for all of our own actions: these include safety, protecting the environment, and supporting our communities.
- We work together as a team and are committed to excellence and innovation.
- We respect each other and celebrate our diversity.

Another clear sign that we are changing old practices was the amount of time senior leaders and I spent in the field in 2005. We talked with and listened to our people face-to-face in locations across our service area.

At different times these conversations have been inspiring, eye-opening, energizing and humbling. But they have also been consistently refreshing and invaluable in guiding decisions about Transformation.

We heard directly from PG&E employees about how to make our operations work better. This is critical. They are on the front lines with our customers every day, and they understand where the needs and opportunities for improvement are.

We are increasing our employee engagement efforts in 2006. Our leadership team has committed to significantly increase the time we invest in this area.

Another important sign of change is the broad-based involvement of our employees in designing and implementing the changes going on now within the organization. This, too, will be ramped up in 2006.

WE BUILT A LEADERSHIP TEAM FOR THE FUTURE.

We added incredible new talent and experience to PG&E's senior leadership in 2005. The diversity of management backgrounds and expertise on our team is now as strong or stronger than it has ever been. Uniquely for our industry, it integrates people who have been high-impact leaders both in regulated utilities and in the competitive world.

On January 1 of this year, Tom King became President and CEO of Pacific Gas and Electric Company. Tom led PG&E's Transformation effort in 2005. His new ideas, energy and commitment to PG&E make him the ideal choice to lead the utility into its next 100 years.

We also said fond farewells to two leaders – Bob Glynn, Jr., and Gordon Smith – who were indispensable in bringing PG&E through the most difficult challenge in its history, the California energy crisis. The opportunities that PG&E has today are possible because of the platform built under Bob's and Gordon's leadership. We thank them, and we wish them the best.

WE PLANTED A FIRM STAKE IN THE GROUND.

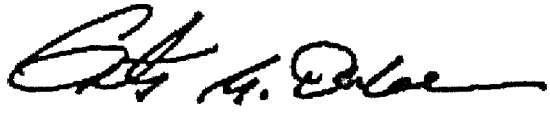
If one thought sums up 2005, it may be this: PG&E put a firm stake in the ground with respect to its view of where the industry is going, where we want PG&E to be, and how we intend to pull it off.

I have every confidence that we will succeed – that we are right about the direction of the industry, that delivering for our customers is the strategy that promises the strongest returns for our shareholders in the long term, and that PG&E will realize its vision to be the leading utility in the United States.

When we do, our customers will be delighted, and we will have tremendous opportunities to build on our success for our shareholders and employees.

We hope you will be watching us.

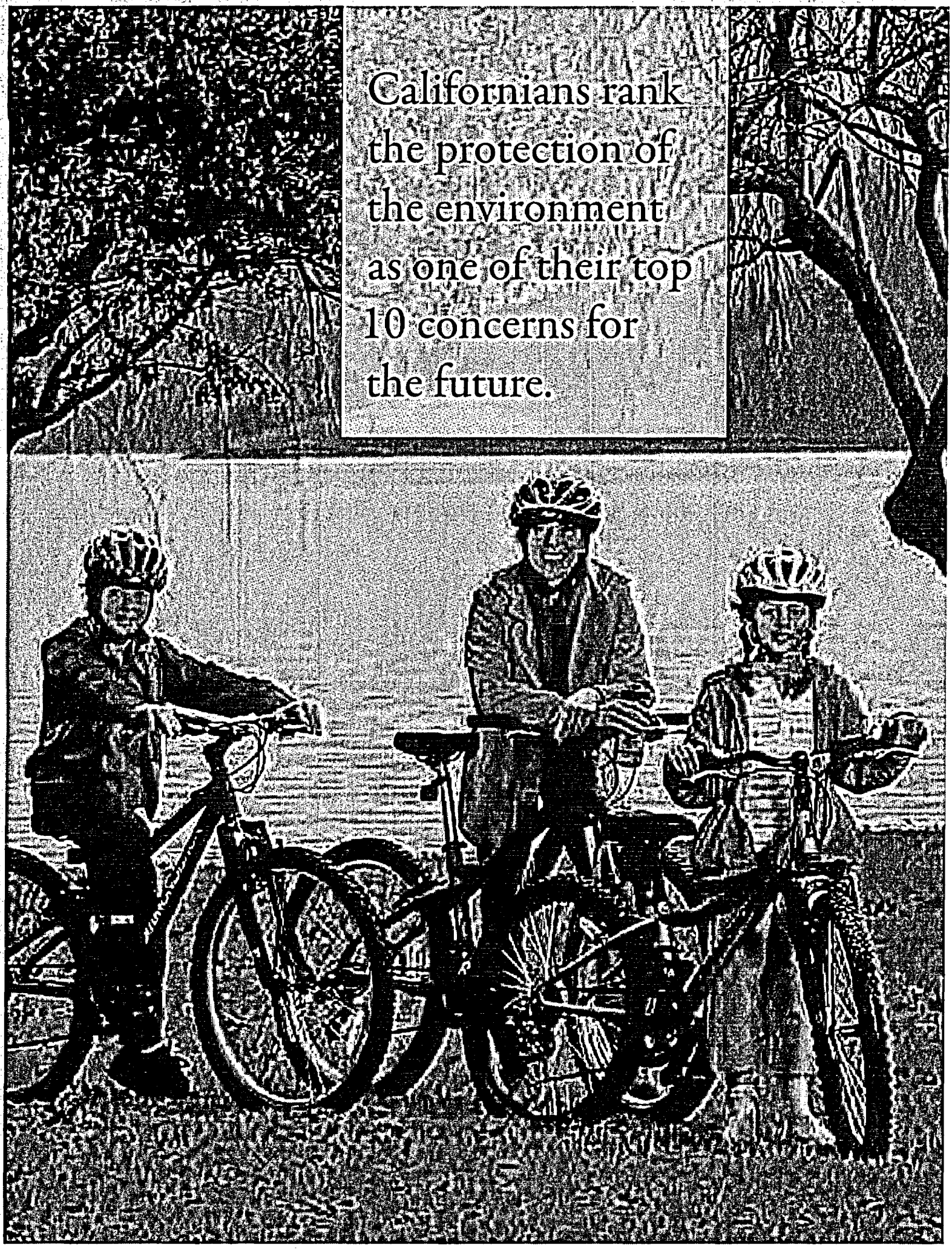
Sincerely,



Peter A. Darbee
Chairman of the Board, CEO and President
PG&E Corporation

Chairman of the Board
Pacific Gas and Electric Company
February 21, 2006

More than ever, we are looking at the job we do through the eyes of our 15 million customers. ▫ Every day, they count on PG&E to be there – when they flip on a light, turn up the thermostat, need service, or want advice on saving energy and money. ▫ They count on us to make the right decisions for California's energy future and its economy. ▫ To protect the environment for the next generation. ▫ To be good neighbors. ▫ And to care about and contribute to the quality of life in our communities as much as they do. ▫ Seeing ourselves from their perspective is changing the way we work. It's laying the foundation for a better customer experience. And it's essential to building a stronger PG&E for the future.


Californians rank
the protection of
the environment
as one of their top
10 concerns for
the future.

Demonstrating Environmental Leadership

PG&E is working to satisfy the demand for energy in a way that respects the environment, allowing future generations to enjoy the beauty of California as we do today.

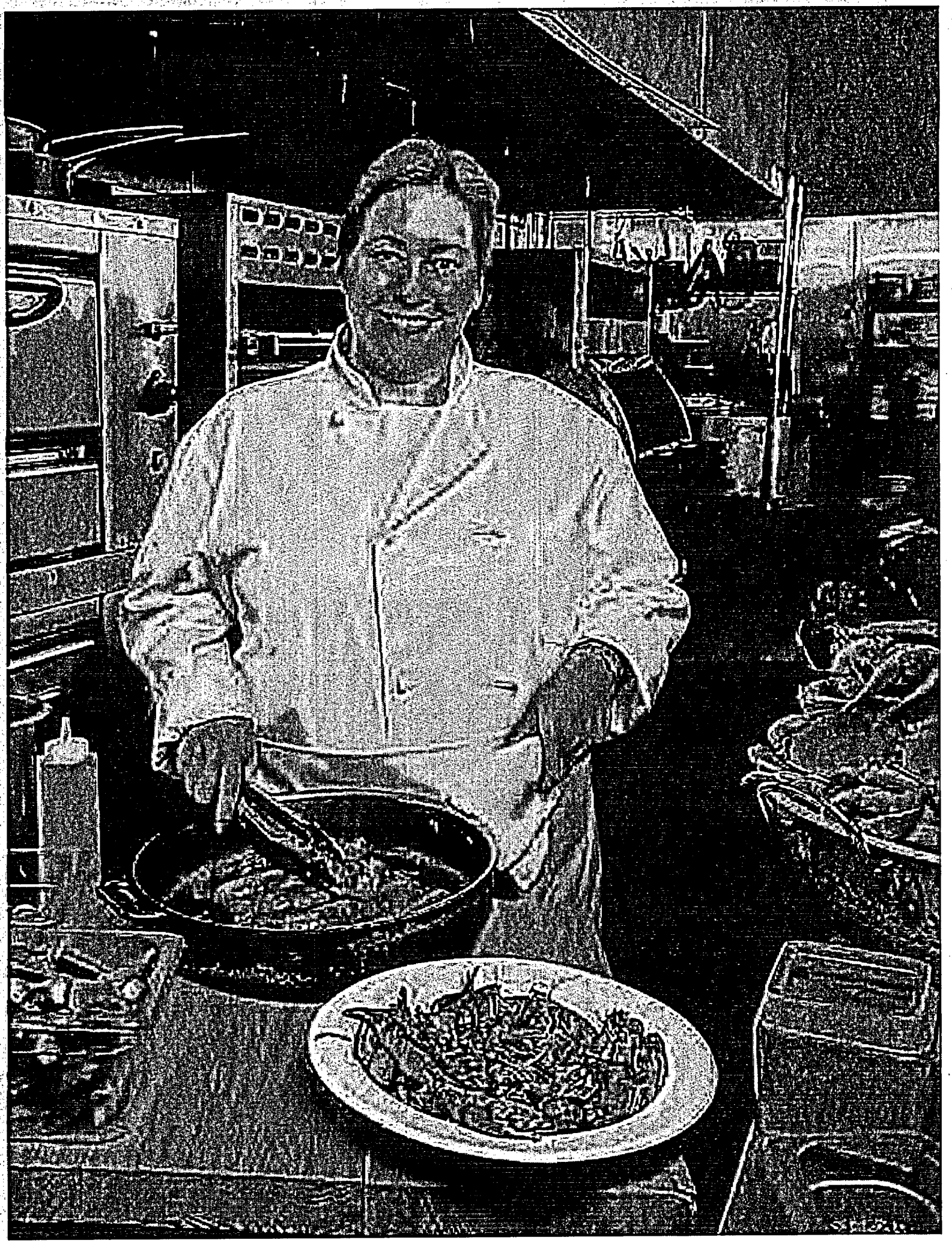
We know that the way we produce and deliver products and serve customers has a direct impact on the environment, which is why environmental considerations are an integral part of every decision we make. We challenge ourselves to do more with less impact, and we strive to leave our environment in the same condition as we found it, or better, if possible. Our programs to protect air and water quality, conserve wildlife habitat, and address climate change have been nationally recognized and have raised the bar not only within our industry, but for U.S. industries in general. A proposal we now have before the California Public Utilities Commission seeks to launch a first-of-its-kind Climate Protection Program, which invites customers to join us in our efforts to cut greenhouse gas emissions. The three-year pilot program has the potential to remove more than 2 million tons of carbon dioxide from the air – the equivalent of keeping 350,000 cars off the road for a year.

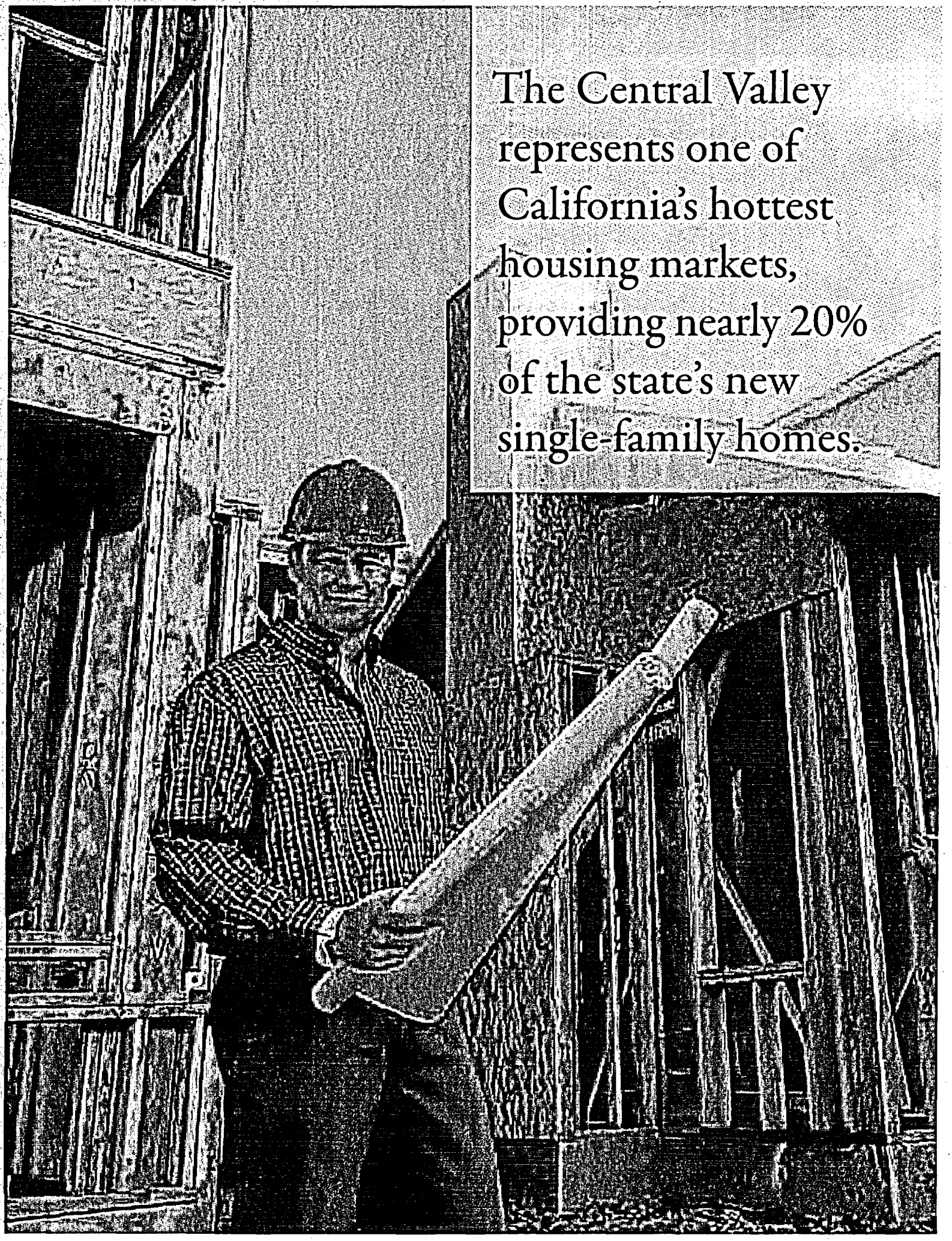
Serving Up Energy Solutions

For decades restaurants have looked to PG&E for advice on the most energy-efficient products.

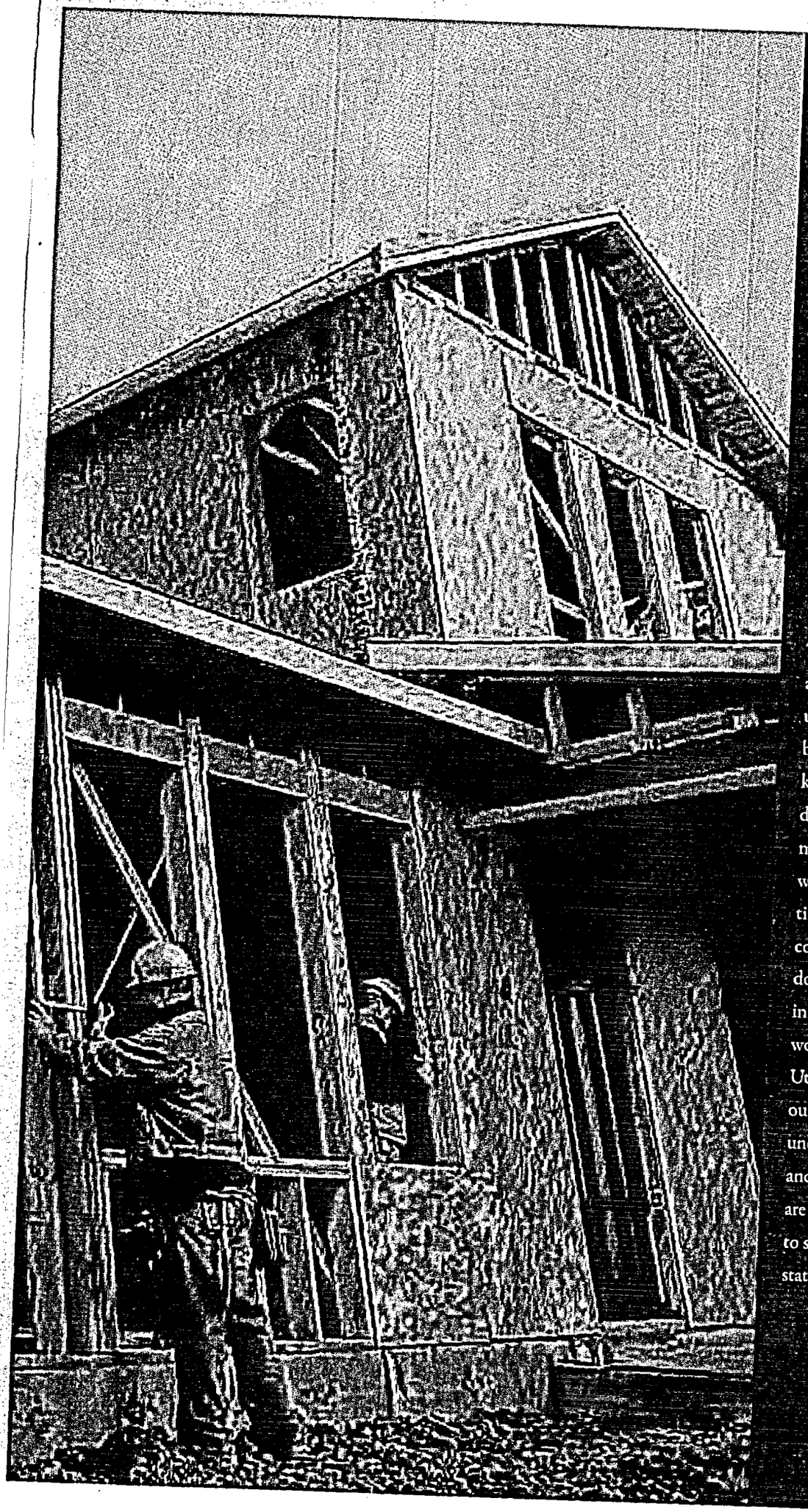
Up to 5 percent of the average restaurant's total operating costs are spent on energy. In a business where profit margins are tight, restaurants can look to PG&E to help boost their bottom line by reducing energy use – a 20 percent cut in energy use can mean an additional 1 percent of profit. Since 1987, PG&E's Food Service Technology Center (FSTC) has tested and reported on the energy performance of various kitchen equipment and food preparation appliances. Over the years, our FSTC consulting service has won national recognition from food service operators, kitchen designers and cooking equipment manufacturers as a source of unbiased and comprehensive information about energy use and conservation. Our support for this industry has also included providing financial incentives to encourage the purchase of more energy-efficient equipment. Our current incentive program covers five categories of cooking equipment, commercial freezers and refrigerators, and ice machines, with more categories to be added in 2006.

With nearly 78,000 eating establishments statewide, the restaurant industry is the largest employer in California.





The Central Valley represents one of California's hottest housing markets, providing nearly 20% of the state's new single-family homes.



Building Partnerships

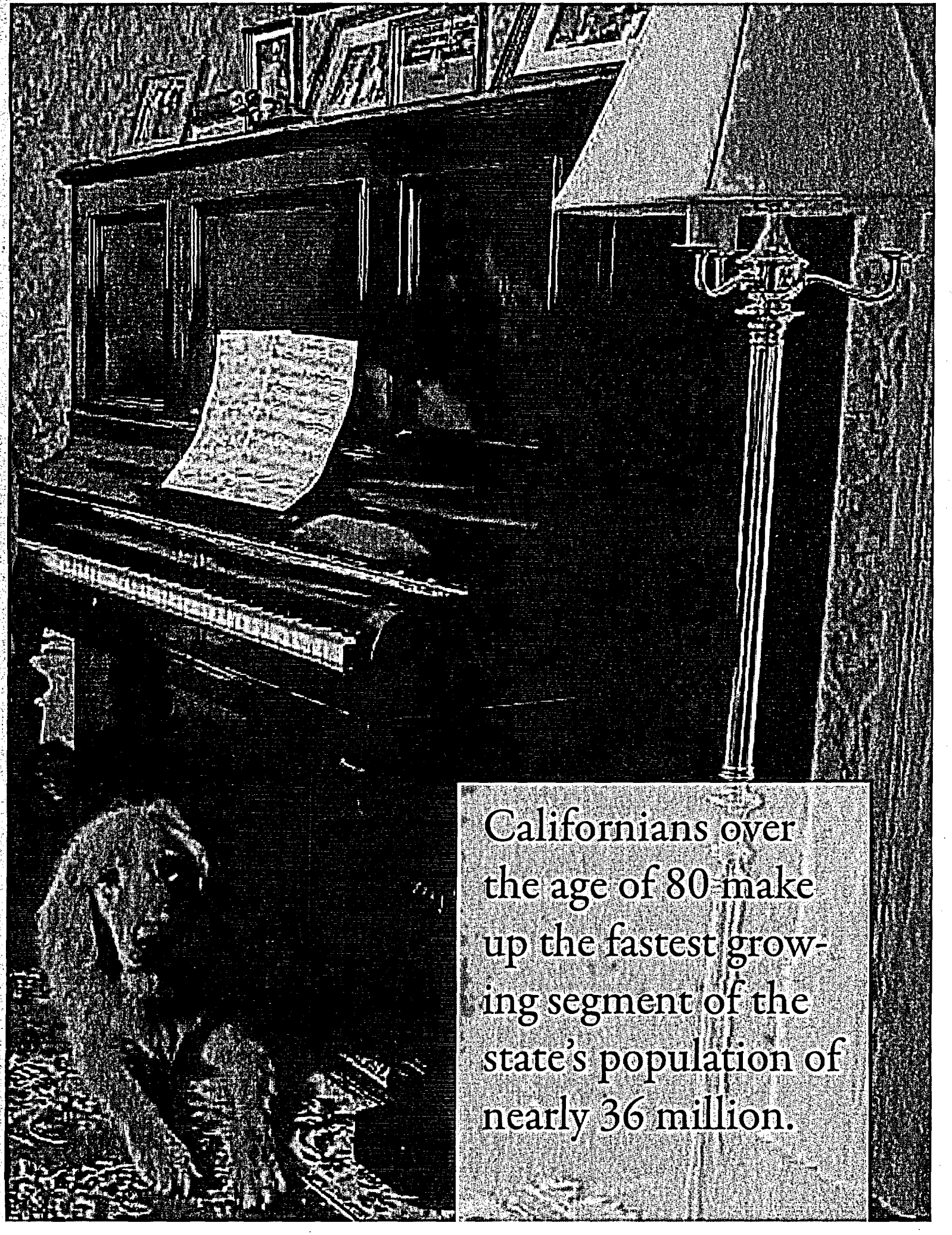
Our goal is to help developers meet their commitments by making sure that we meet ours.

Our customers who build new housing developments rely on us to get their homes hooked up to our gas and electric system in a timely manner. That's why we are making improvements to our processes to serve these customers more efficiently. For example, we are restructuring our design and estimating functions for new subdivision projects of more than 20 homes. Instead of having our 70 regional offices handle their own areas, we consolidated these activities under two central design teams based in Rocklin and Fresno, while keeping the point of contact for developers with local PG&E project managers. Early feedback is positive, with reports of faster response times and standardized designs. We continue streamlining the work we do for developers through other initiatives as well. For example, we're working with the California Public Utilities Commission to simplify our contracts so they are easier to understand and faster to process, and by launching PGeConnect we are making it possible for developers to submit applications and track the status of their projects online.

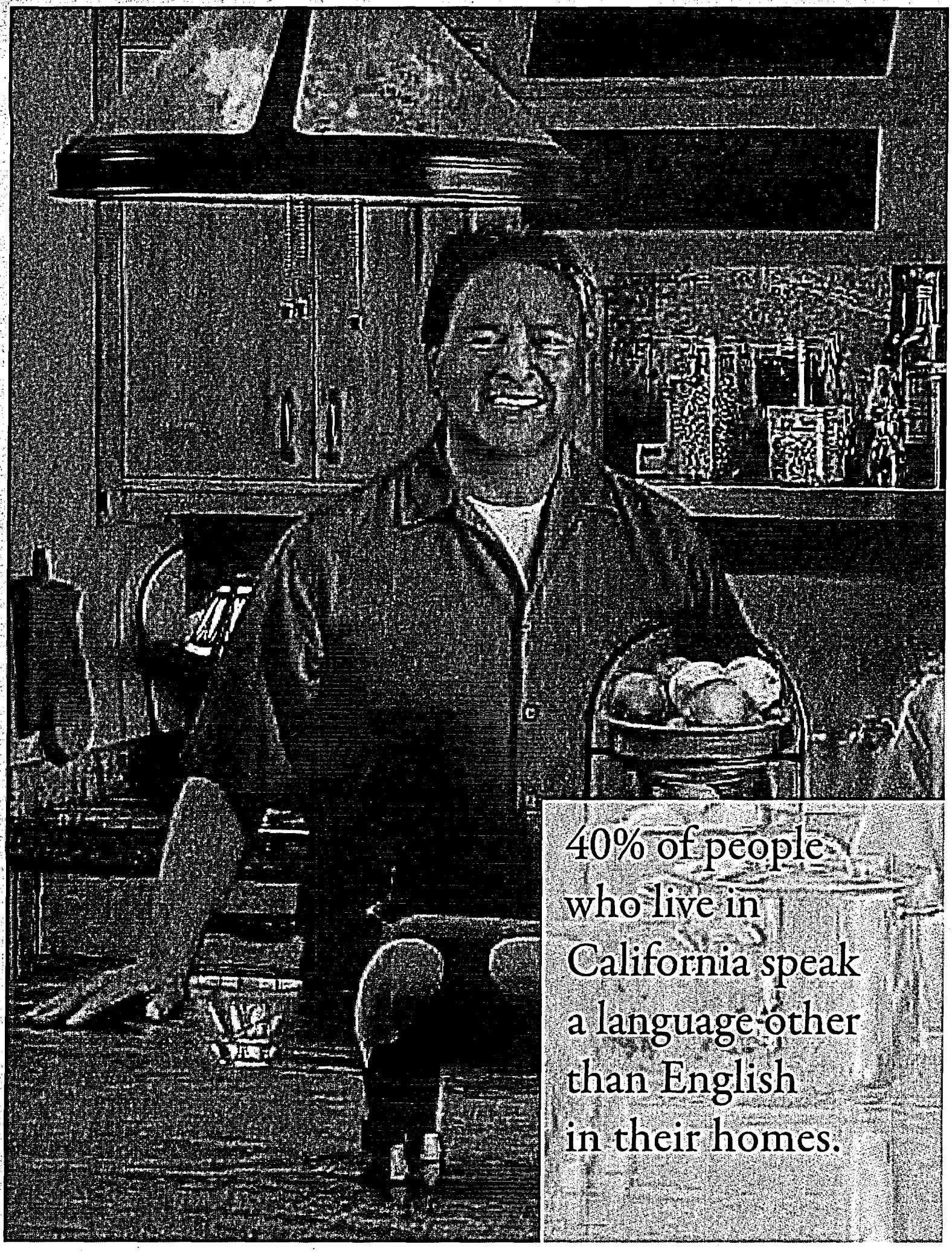
Reaching Out

PG&E lends a helping hand to customers on a fixed or limited income, including those who are elderly or disabled.

Maintaining utility service can sometimes be a challenge for California's fast-growing senior population. Not only are some on a limited income, but health concerns make it difficult for many to cut back on their energy use. Also, many seniors live in older homes with less insulation and older, less efficient appliances. At PG&E, we believe we have a responsibility to help. In addition to offering advice on low-cost or no-cost ways to reduce energy usage, giving rebates on new energy-efficient appliances, and providing qualified customers free weather-stripping and insulation, we also offer a number of alternative bill payment and financial assistance plans. Currently, more than 1 million customers participate in our CARE program, which enables income-qualified households to save 20 percent on their utility bills. Another program, REACH, is designed to help those at risk of losing service by offering one-time payment assistance. REACH is funded through tax-deductible donations from employees and customers. Additionally, PG&E has contributed $20 million to the program since 1983.



Californians over the age of 80 make up the fastest growing segment of the state's population of nearly 36 million.



40% of people who live in California speak a language other than English in their homes.

Working with Diverse Communities

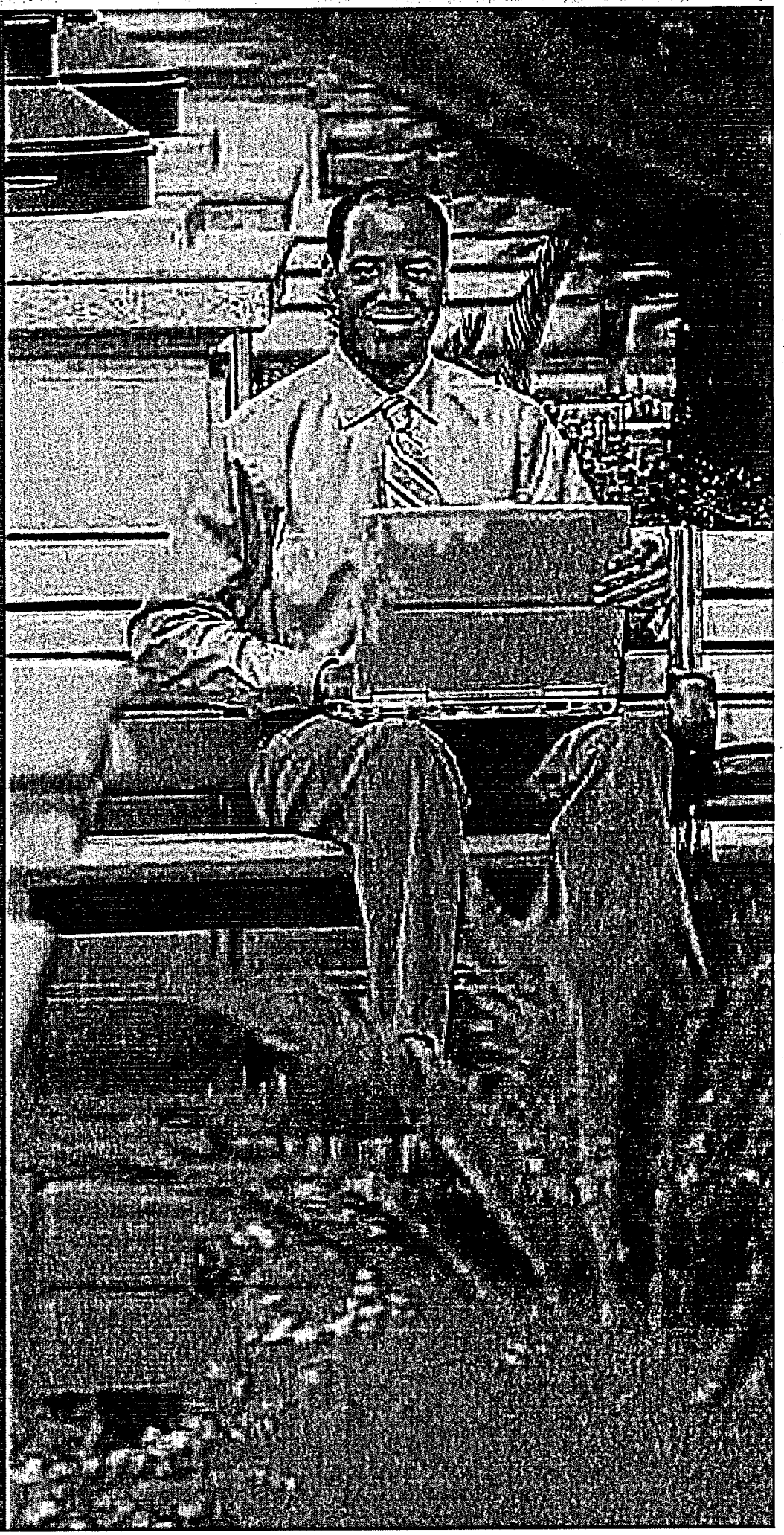
Operating in one of the most diverse states in the nation, PG&E makes it a priority to understand and respond to the needs of its communities.

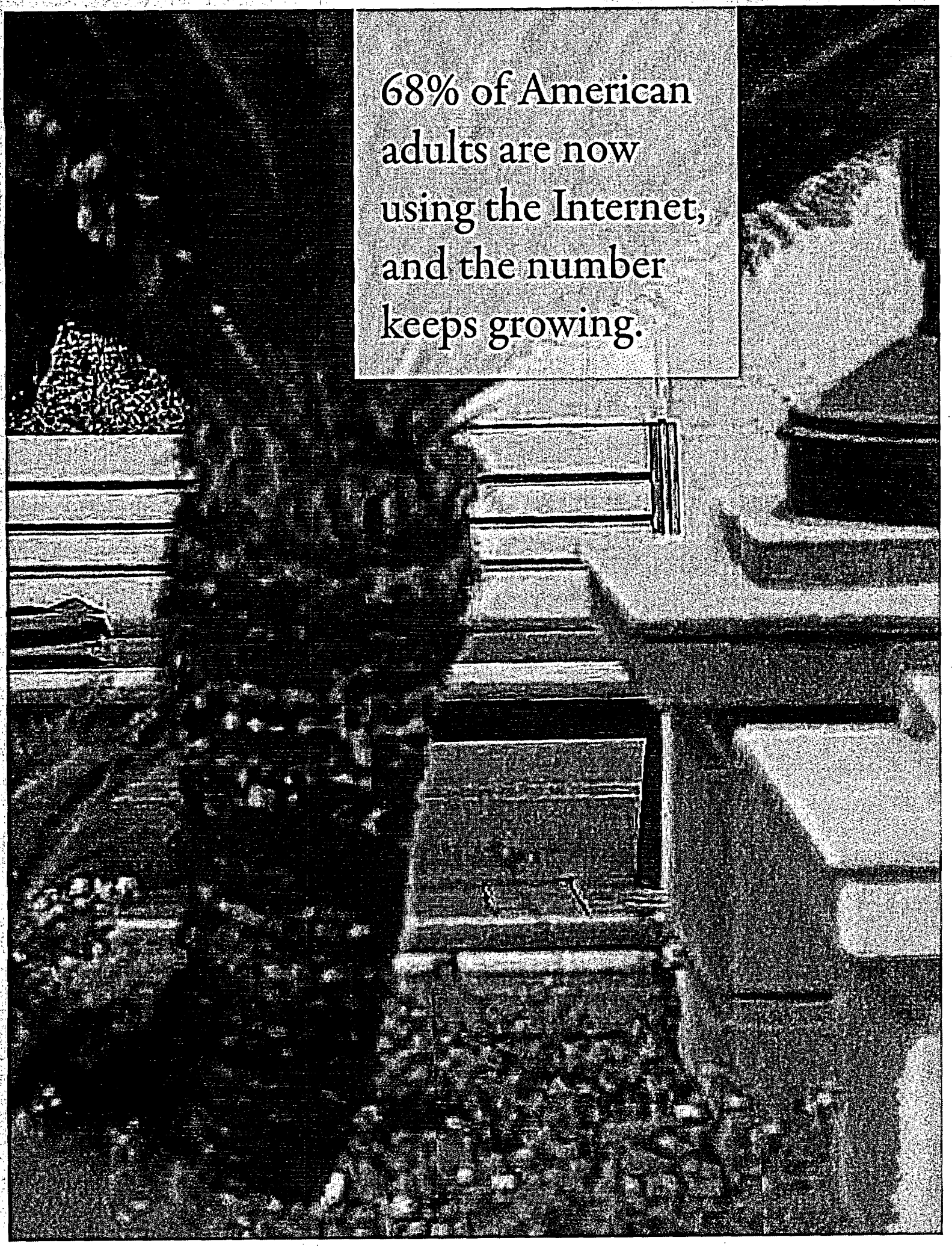
Connecting with California's diverse communities is much more than just communicating in different languages. It's about understanding and respecting how different cultures and customs shape customers' needs and expectations of PG&E – and responding accordingly. To do that, we work to keep a strong presence in diverse communities. We also reach out with informational advertising and other communications in print and broadcast outlets that speak directly to these customers. And we sponsor booths at cultural events such as the Chinese New Year's Parade, Vietnamese Tet celebrations, Cinco de Mayo and African-American Juneteenth observances to provide customers with information about offerings such as energy conservation programs, payment options and PG&E scholarship funds. We also make many forms and brochures available in Spanish, Chinese and Vietnamese, and for the 26 percent of Spanish-speaking households in our region, we recently launched pge.com/espanol to provide online access to account and service information all *en español.*

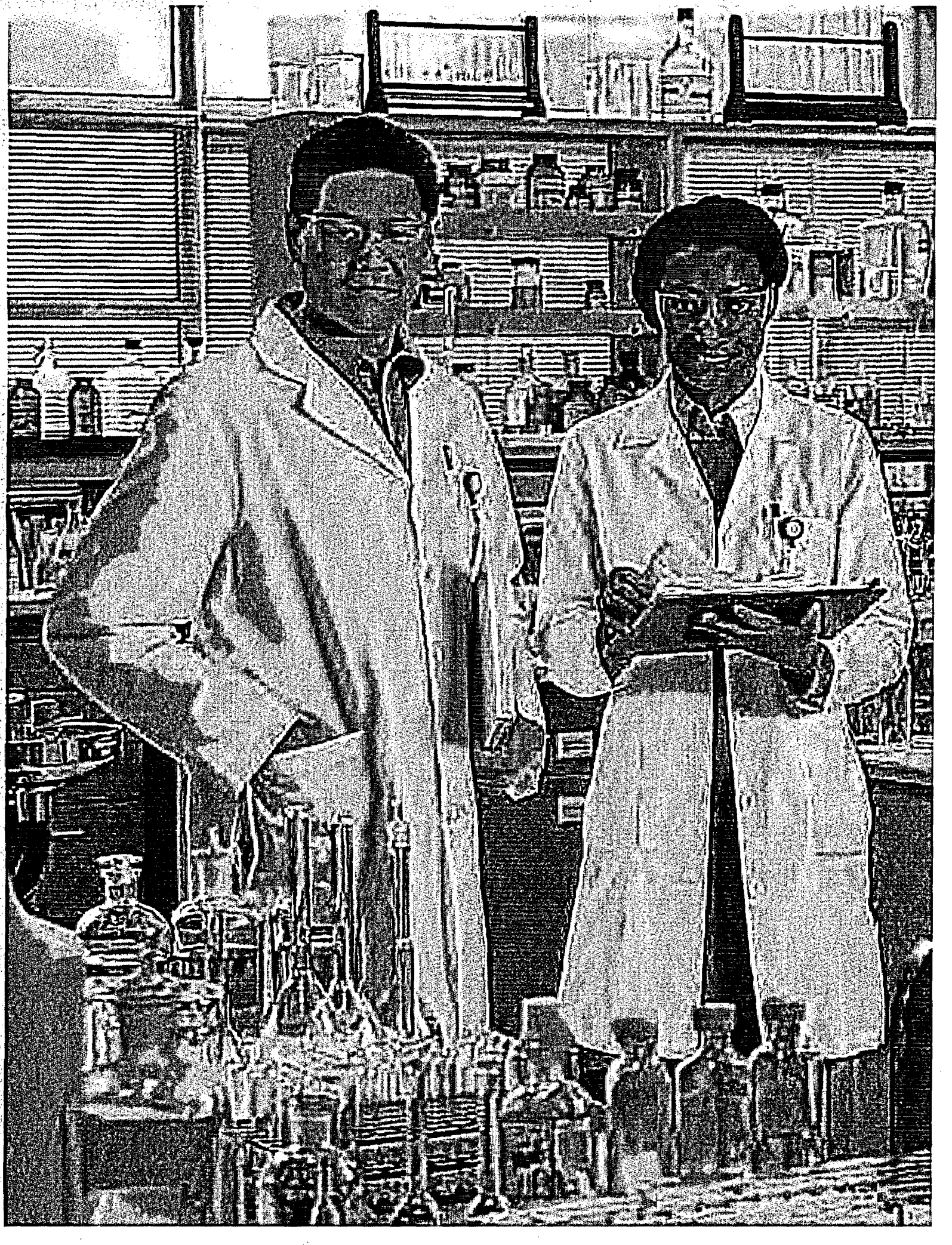
Serving Customers Online

As the web becomes a part of daily life for more and more of our customers, we are expanding their options to connect with PG&E.

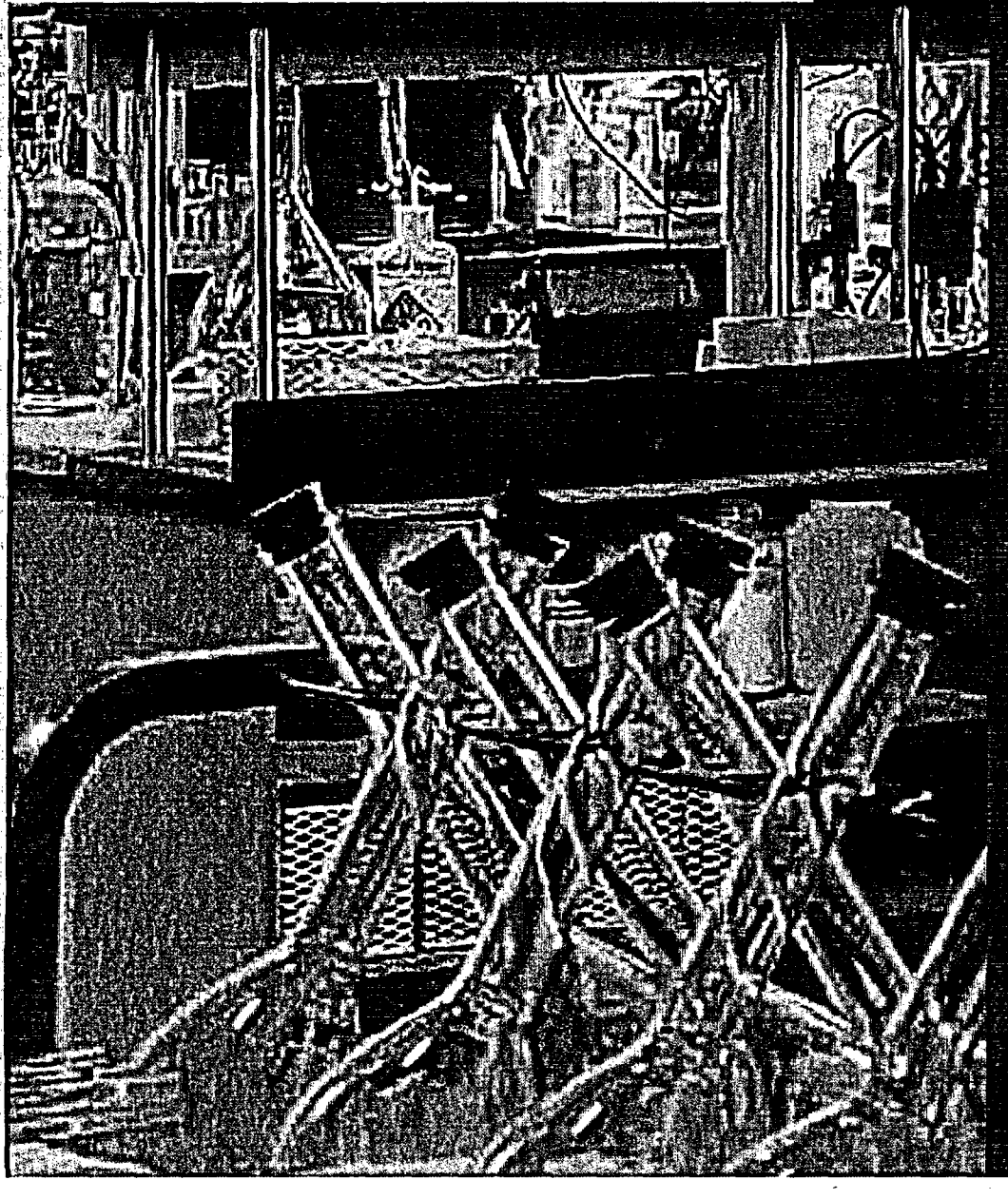
We are putting online technology to work for our customers in a broad number of ways. By logging onto pge.com, customers enjoy 24/7 access to their account information, along with the ease of paying bills, scheduling gas service appointments, applying for energy efficiency rebates and even checking their PG&E credit history. It is simple, convenient and, very importantly, it saves paper and postage both for us and our customers. For instance, every 38,500 bills delivered through e-Bills saves one ton of paper and avoids the equivalent of more than 5,000 pounds of carbon dioxide. Not bad. Expanding online service for customers is one of the benefits we expect as a result of our plans to install SmartMeters at homes and businesses in our service area starting this year. This remote meter reading capability eliminates the need for PG&E to manually read meters one house at a time, while enabling remote detection of outages and allowing electric service to be turned on without site visits. Customers will benefit from the ability to monitor energy usage online, giving them access to information that will help them manage their energy costs.




68% of American adults are now using the Internet, and the number keeps growing.



San Francisco Bay Area companies continue to provide many of the biggest breakthroughs in high-tech and biotech research today.



Focusing on Reliability

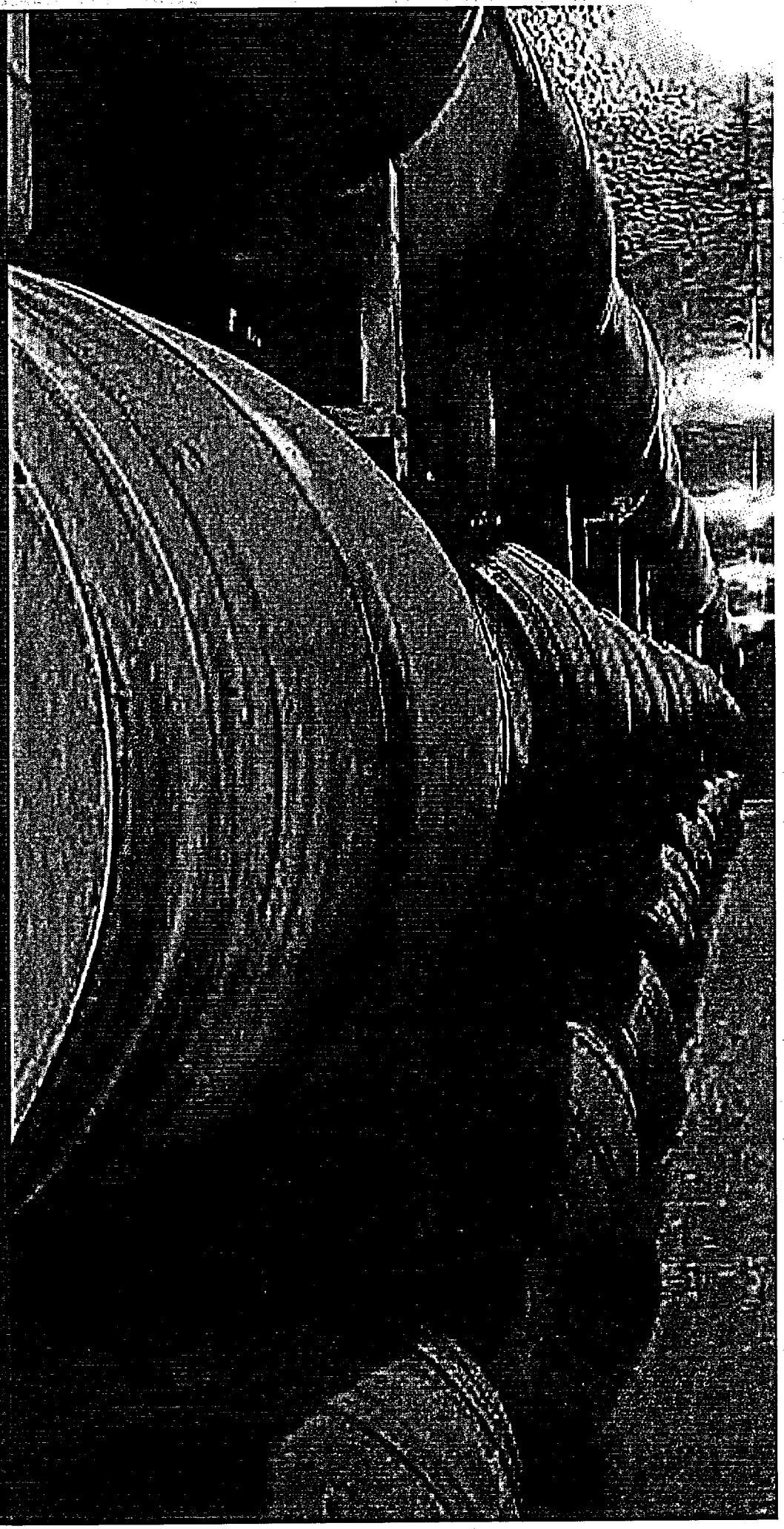
Reliable, efficient power is a must for our high-tech and biotech customers.

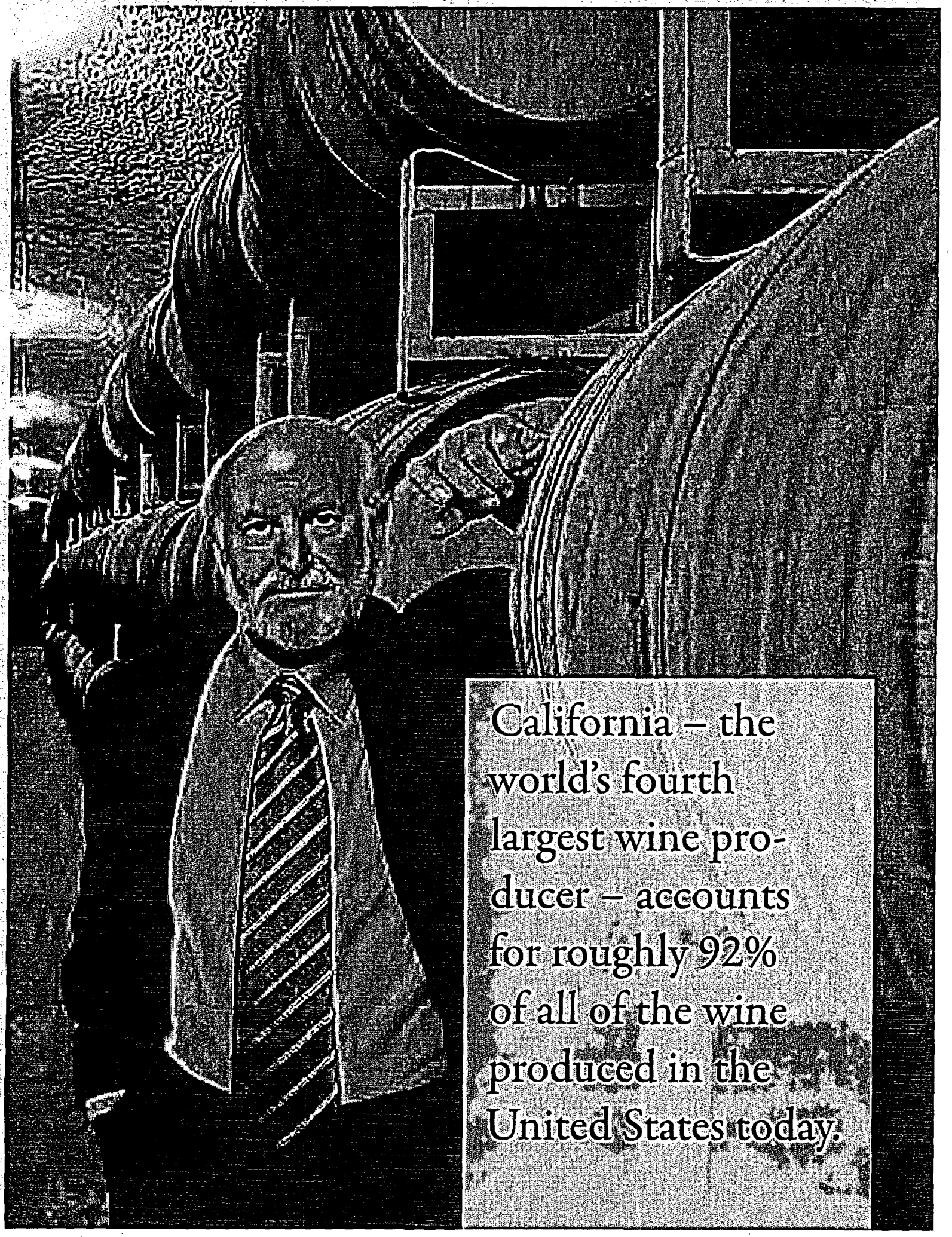
High-tech businesses demand tremendous amounts of energy – a cleanroom or a high-density data center consumes up to 100 times more power per square foot than a typical office building. Energy costs can be more than $1 million per month. These facilities also demand a 24/7 energy supply. For example, in a biotech lab, any interruption could represent a potential crisis. These factors make managing energy usage a critical strategic concern for these customers. PG&E's energy efficiency expertise offers both an opportunity to realize major cost-savings and an important way to lower overall demand, which means diminished stress on the grid and enhanced system reliability. We are working closely with some of the leading companies in the high-tech industry to show them ways they can reduce usage at their facilities. We are partnering with these customers to assess their energy needs and provide a portfolio of solutions, including energy efficiency and conservation measures, time-of-use management, and solar and other on-site generation options. These options, implemented over time, are now saving one of our customers more than $7 million per year.

Harvesting Efficiency

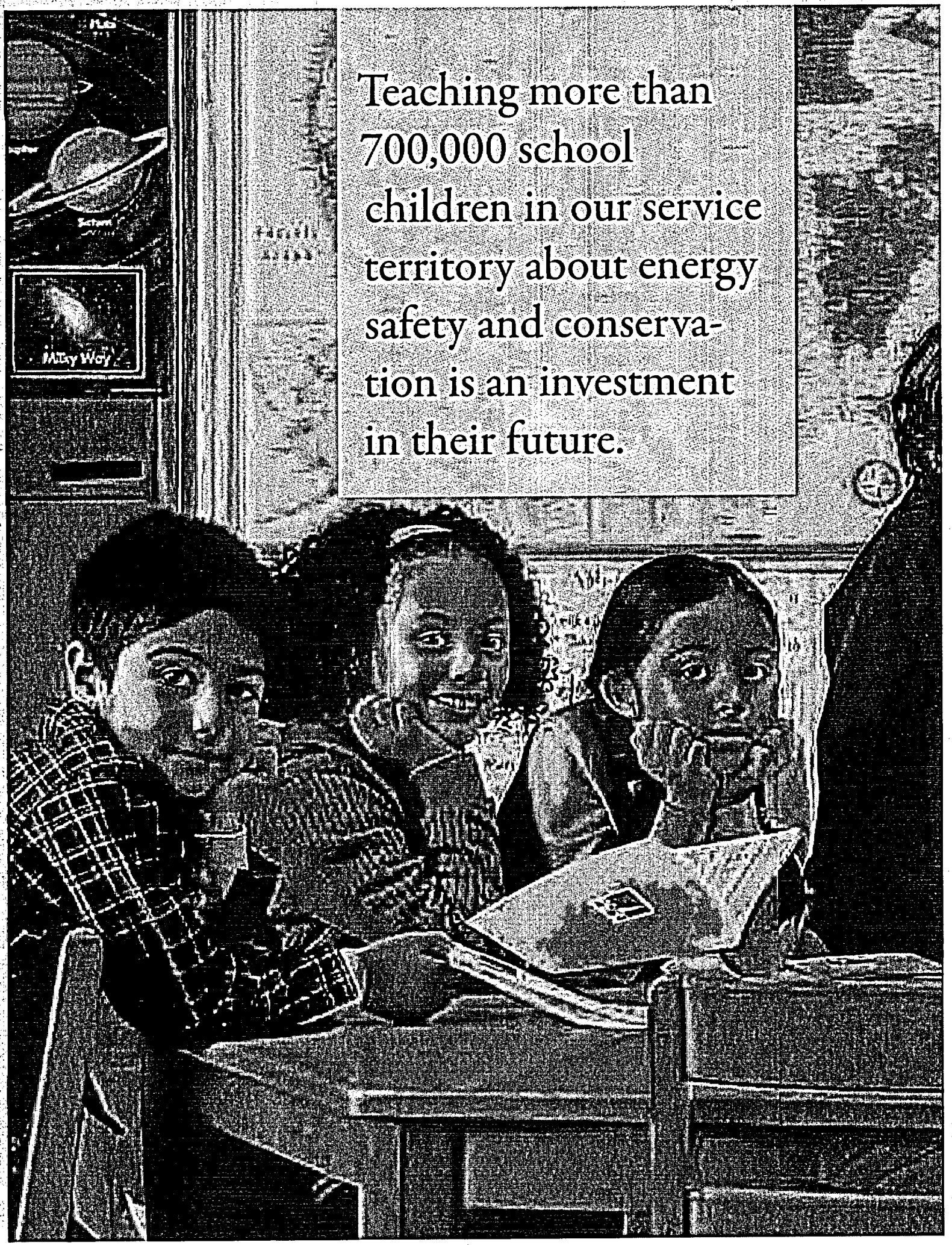
PG&E is helping vintners reduce energy usage in a green and sustainable manner.

In California, winegrowing is not only a major agricultural business, it is a significant contributor to state tourism. Winegrowers also are the biggest users of energy among food processors in PG&E's service territory. Over the past year, we teamed with Lawrence Berkeley National Laboratory to develop energy auditing software specifically for winegrowers. Our BEST (Benchmarking and Energy and Water Savings Tool) program allows users to model hundreds of energy efficiency improvements and view data on best available technologies. As a follow-on to this initiative, we co-host workshops with the Wine Institute's Sustainable Winegrowing Program to brief customers on energy conservation techniques. As a further incentive, we offer financial rebates for converting to energy-efficient equipment such as insulated wine tanks, lighting for case and barrel warehousing, refrigeration controls and compressed air systems.





California – the world's fourth largest wine producer – accounts for roughly 92% of all of the wine produced in the United States today.


Teaching more than 700,000 school children in our service territory about energy safety and conservation is an investment in their future.

Making a Difference

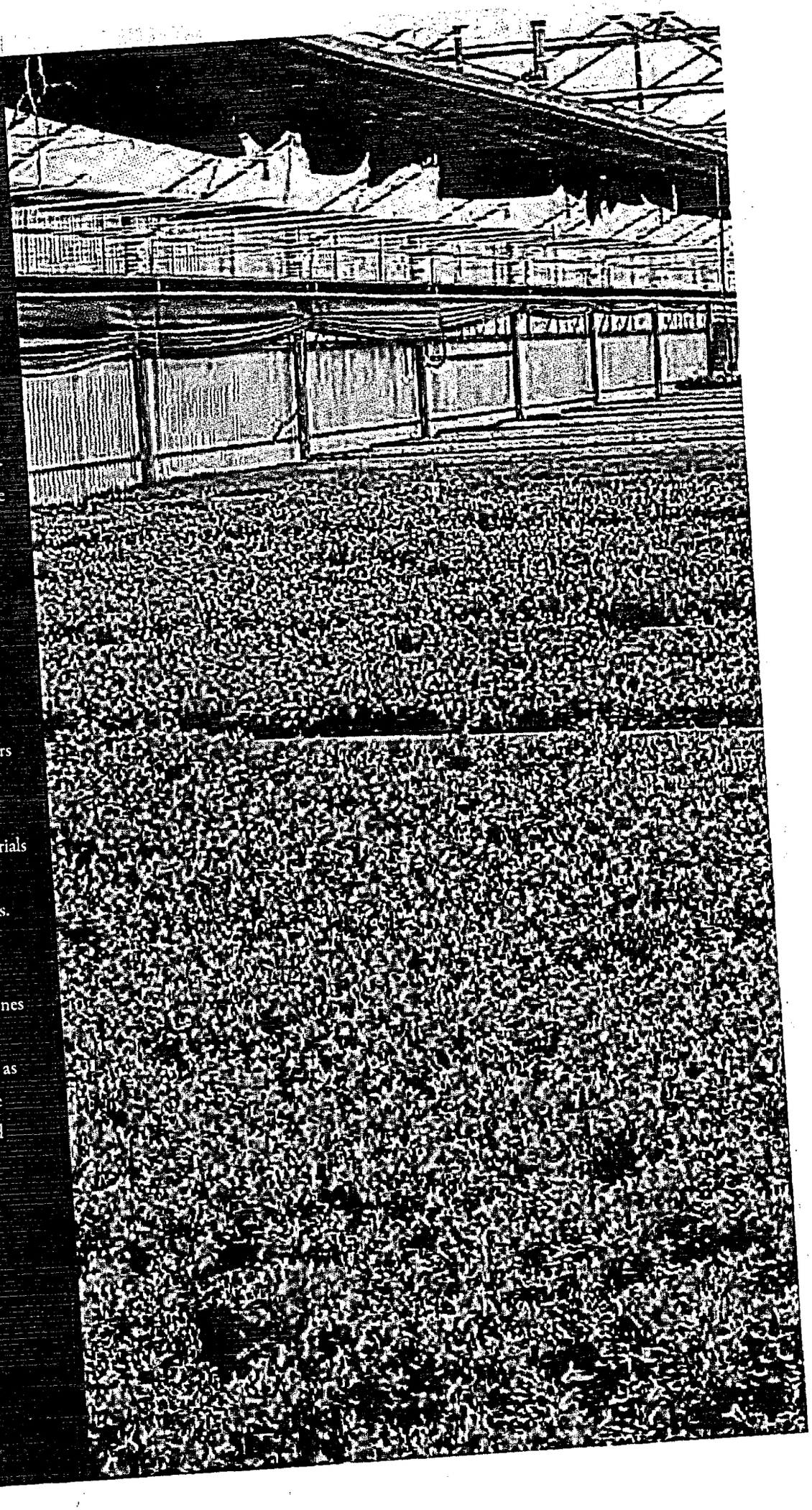
By partnering with our 20,000 employees, our customers and local nonprofit organizations, PG&E works to improve the quality of life in our communities.

Corporate philanthropy is more than charitable giving at PG&E; we lead by example. While our charitable contributions program reached $12 million in 2005, our actual contribution was far greater, thanks to the volunteerism of our employees who turned out by the hundreds to participate in Earth Day clean-up activities and other worthwhile causes. Wherever possible, we strive to engage both our own people and our expertise in the interest of our communities. A partnership with Habitat for Humanity is focusing on providing the resources and know-how to install solar panels on housing in underserved communities. Our Solar Schools Program is benefiting the community in multiple ways. Participating schools receive free installation of a small-scale solar electric system, along with a specialized curriculum and teacher training on how energy can be harnessed from alternative sources. The program reduces the schools' energy costs, provides clean energy that benefits the environment, and teaches students about alternative energy. The effort has been a success, and we are expanding it in 2006.

Helping Businesses Grow

PG&E is helping floral and nursery producers stay globally competitive by identifying ways to cut energy costs.

Every industry has its own distinct energy usage patterns that PG&E works to analyze and address with specific programs. For the floral and nursery business, energy consumption represents the second-largest expenditure, just behind labor. Reducing these energy costs has taken on greater urgency, particularly for cut-flower growers who are facing stiff foreign competition. PG&E technical consultants are actively engaged in presenting ways to lower operating expenses through on-site energy audits and efforts to keep producers apprised of advanced greenhouse design principles, conservation techniques, and new types of materials engineered to reduce greenhouse heat loss and energy inefficiencies. Measures such as thermal heat curtains, infrared glazing, and converting irrigation pump engines from fossil fuel to electric offer substantial cost-savings as well as environmental benefits, and are eligible for cash incentives and rebates from PG&E.



Floral and nursery product sales combined rank second among all California agricultural products.

PG&E CORPORATION AND PACIFIC GAS AND ELECTRIC COMPANY FINANCIAL STATEMENTS

FINANCIAL STATEMENTS
TABLE OF CONTENTS

FINANCIAL HIGHLIGHTS

PG&E Corporation

(unaudited, in millions, except share and per share amounts)	2005	2004
Operating Revenues	$ 11,703	$ 11,080
Net Income		
Earnings from operations[1]	$ 906	$ 901
Items impacting comparability[2]	(2)	2,919
NEGT	13	684
Reported consolidated net income	$ 917	$ 4,504
Income Per Common Share, diluted[3]		
Earnings from operations[1]	$ 2.34	$ 2.12
Items impacting comparability[2]	—	6.85
NEGT	0.03	1.60
Reported consolidated net earnings per common share, diluted	$ 2.37	$ 10.57
Dividends Declared Per Common Share	$ 1.23	—
Total Assets at December 31,	$ 34,074	$ 34,540
Number of common shareholders at December 31,	98,252	104,703
Number of common shares outstanding at December 31,[4]	368,268,502	418,616,141

(1) Earnings from operations does not meet the guidelines of accounting principles generally accepted in the United States of America, or GAAP. It should not be considered an alternative to net income. It reflects net income of PG&E Corporation, on a stand-alone basis, and the Utility, but excludes items impacting comparability, in order to provide a measure that allows investors to compare the core underlying financial performance of the business from one period to another, exclusive of items that management believes do not reflect the normal course of operations.

(2) Items impacting comparability represent items that management does not believe are reflective of normal, core operations. Items impacting comparability for 2005 include:

- The net effect of incremental interest costs of approximately $3 million ($0.01 per share), after-tax, incurred by the Utility through February 10, 2005 related to generator disputed claims in the Utility's Chapter 11 proceeding, which are not considered recoverable;
- Annual Earnings Assessment Proceeding revenues of approximately $93 million ($0.24 per share), after-tax, as a result of an October 27, 2005 CPUC decision allowing the Utility to recover shareholder incentives for successful implementation for certain public purpose programs; and
- An additional accrual of $91 million ($0.23 per share), after-tax, to reflect both the February 3, 2006 settlement of most of the claims in the "Chromium Litigation" pending against the Utility and an accrual for the remaining unresolved claims.

Items impacting comparability for 2004 include:

- A gain of approximately $2,950 million ($6.92 per share) related to the establishment of regulatory assets contemplated in the December 19, 2003 settlement agreement, or Settlement Agreement, entered into between the Utility, PG&E Corporation and the CPUC to resolve the Utility's Chapter 11 proceeding;
- A recovery of approximately $30 million ($0.07 per share), after-tax, reflecting a December 2, 2004 CPUC decision approving recovery of previously incurred costs related to the implementation of electric industry restructuring;
- A gain of approximately $120 million ($0.28 per share), after-tax, related to the prior year impact and regulatory asset recognition resulting from the CPUC decision approving the 2003 GRC;
- A charge of approximately $80 million which includes the net effect of incremental interest costs of $53 million, after-tax, incurred by the Utility and $14 million, after-tax, incurred by PG&E Corporation, related to the amount and cost of debt resulting from the California energy crisis and the Utility's Chapter 11 filing, and $13 million ($0.03 per share), after-tax, primarily consisting of external legal consulting fees, financial advisory fees, and other costs related to the Utility's and NEGT's Chapter 11 filings;
- A charge of approximately $30 million ($0.07 per share), after-tax, associated with the redemption of PG&E Corporation's $600 million 6¾% Senior Secured Notes on November 15, 2004;
- A charge related to the change in the estimated value of non-cumulative dividend participation rights of $54 million ($0.13 per share) included within PG&E Corporation's $280 million principal amount of 9.50% Convertible Subordinated Notes; and
- Charges of $17 million ($0.04 per share) related to obligations to invest in clean energy technology and donate land, included in the Settlement Agreement.

(3) Reflects adoption of the "Two-Class" method of calculating earnings per share for all periods presented.

(4) Common shares outstanding include 24,665,500 shares at December 31, 2005 and December 31, 2004, held by a wholly owned subsidiary of PG&E Corporation. These shares are treated as treasury stock in the Consolidated Financial Statements.

SELECTED FINANCIAL DATA

(in millions, except per share amounts)	2005	2004	2003	2002	2001
PG&E Corporation[1]					
For the Year					
Operating revenues	$11,703	$11,080	$10,435	$10,505	$10,450
Operating income	1,970	7,118	2,343	3,954	2,613
Income from continuing operations	904	3,820	791	1,723	1,021
Earnings per common share from continuing operations, basic	2.37	9.16	1.96	4.53	2.81
Earnings per common share from continuing operations, diluted	2.34	8.97	1.92	4.49	2.80
Dividends declared per common share[2]	1.23	–	–	–	–
At Year-End					
Book value per common share[3]	$ 19.94	$ 20.90	$ 10.16	$ 8.92	$ 11.91
Common stock price per share	37.12	33.28	27.77	13.90	19.24
Total assets	34,074	34,540	30,175	36,081	38,529
Long-term debt (excluding current portion)	6,976	7,323	3,314	3,715	3,923
Rate reduction bonds (excluding current portion)	290	580	870	1,160	1,450
Energy recovery bonds (excluding current portion)	2,276	–	–	–	–
Financial debt subject to compromise	–	–	5,603	5,605	5,651
Preferred stock of subsidiary with mandatory redemption provisions	–	122	137	137	137
Pacific Gas and Electric Company[1]					
For the Year					
Operating revenues	$11,704	$11,080	$10,438	$10,514	$10,462
Operating income	1,970	7,144	2,339	3,913	2,478
Income available for common stock	918	3,961	901	1,794	990
At Year-End					
Total assets	$33,783	$34,302	$29,066	$27,593	$28,105
Long-term debt (excluding current portion)	6,696	7,043	2,431	2,739	3,019
Rate reduction bonds (excluding current portion)	290	580	870	1,160	1,450
Energy recovery bonds (excluding current portion)	2,276	–	–	–	–
Financial debt subject to compromise	–	–	5,603	5,605	5,651
Preferred stock with mandatory redemption provisions	–	122	137	137	137

(1) Operating income and income from continuing operations reflect the recognition of regulatory assets in 2004 provided under the December 19, 2003 settlement agreement entered into among PG&E Corporation, the Utility, and the CPUC to resolve the Utility's Chapter 11 proceeding. Matters relating to certain data, including discontinued operations, and the cumulative effect of changes in accounting principles, are discussed in Management's Discussion and Analysis and in the Notes to the Consolidated Financial Statements.

(2) The Board of Directors of PG&E Corporation declared a cash dividend of $0.30 per quarter for the first three quarters of 2005. In the fourth quarter of 2005, the quarterly cash dividend declared was increased to $0.33 per share. See Note 8 of the Notes to the Consolidated Financial Statements for further discussion.

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

OVERVIEW

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

In April 2001, the Utility filed a petition under the provisions of Chapter 11 of the U.S. Bankruptcy Code, or Chapter 11. On April 12, 2004, the Utility's Chapter 11 plan of reorganization became effective. The Utility's plan of reorganization incorporated the terms of the nine-year settlement agreement approved by the California Public Utilities Commission, or the CPUC, on December 18, 2003, and entered into among the CPUC, the Utility and PG&E Corporation on December 19, 2003, to resolve the Utility's Chapter 11 proceeding, or the Settlement Agreement. The U.S. Bankruptcy Court for the Northern District of California, where the Utility's Chapter 11 case was pending, confirmed the Utility's plan of reorganization on December 22, 2003. As discussed in Note 15 of the Notes to the Consolidated Financial Statements, an appeal of the confirmation order remains pending. Through October 29, 2004, PG&E Corporation also owned National Energy & Gas Transmission, Inc., or NEGT, formerly known as PG&E National Energy Group, Inc., which engaged in electricity generation and natural gas transportation in the United States and which is accounted for as discontinued operations in PG&E Corporation's financial statements, as discussed in Note 7 of the Notes to the Consolidated Financial Statements.

The Utility served approximately 5 million electricity distribution customers and approximately 4.2 million natural gas distribution customers at December 31, 2005. The Utility had approximately $33.8 billion in assets at December 31, 2005 and generated revenues of approximately $11.7 billion in 2005. Its revenues are generated mainly through the sale and delivery of electricity and natural gas.

The Utility is regulated primarily by the CPUC and the Federal Energy Regulatory Commission, or the FERC. The CPUC has jurisdiction to set the rates, terms and conditions of service for the Utility's electricity distribution, electricity generation, natural gas distribution and natural gas transportation and storage services in California, among other matters. The CPUC also is responsible for setting service levels and certain operating practices and for reviewing the Utility's capital and operating costs. In certain cases, the CPUC prescribes specific accounting treatment for capital and operating costs. The FERC has jurisdiction to set the rates, terms and conditions of service for the Utility's electricity transmission operations and wholesale electricity sales.

The CPUC and the FERC determine the amount of "revenue requirements" the Utility is authorized to collect from its customers to recover the Utility's operating and capital costs. Revenue requirements are primarily determined based on the Utility's forecast of future costs, including electricity and natural gas procurement costs. Changes in any individual revenue requirement will affect customers' electricity and gas rates and the Utility's revenues. Revenue requirements are designed to allow the Utility an opportunity to recover its reasonable costs of providing utility services, including a return of, and a fair rate of return on, its investment in utility facilities, or rate base. To the extent that the Utility is unable to recover its costs through rates because the Utility's actual costs are determined to be unreasonable or are higher than forecast, the Utility may be unable to earn its authorized rate of return.

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

Consolidated Financial Statements include the accounts of the Utility and its wholly owned and controlled subsidiaries. This combined Management's Discussion and Analysis of Financial Condition and Results of Operations, or MD&A, should be read in conjunction with the Consolidated Financial Statements and Notes to the Consolidated Financial Statements included in this annual report.

KEY FACTORS AFFECTING RESULTS OF OPERATIONS AND FINANCIAL CONDITION

The following key factors had, or are expected to have, a significant impact on PG&E Corporation's and the Utility's results of operations and financial condition:

- *Issuance of Energy Recovery Bonds* – During 2005, PG&E Energy Recovery Funding LLC, a limited liability company wholly owned by the Utility, or PERF, issued two separate series of Energy Recovery Bonds, or ERBs, for the aggregate amount of approximately $2.7 billion. (See Note 6 of the Notes to the Consolidated Financial Statements). The Settlement Agreement established a $2.2 billion, after-tax, regulatory asset ($3.7 billion, pre-tax), or the Settlement Regulatory Asset, on which the Utility was authorized to earn a return on equity, or ROE, of 11.22%. In February 2005, the proceeds of the first series of ERBs in the amount of $1.9 billion were used to refinance the after-tax portion of the Settlement Regulatory Asset. As a result, the Utility's net income for the year ended December 31, 2005, was reduced by approximately $99 million as compared to the same period in 2004, when the Utility earned its authorized 11.22% ROE, on the after-tax portion of the Settlement Regulatory Asset. The November 2005 issuance of the remainder of ERBs in the amount of $844 million had a minimal effect on 2005 net income and is expected to reduce the Utility's 2006 net income, as compared to 2005, by approximately $56 million;

- *Improved Capital Structure* – In January 2005, the equity component of the Utility's capital structure reached 52%, the target specified in the Settlement Agreement. Since this allowed the Utility to restore dividends and repurchase shares held by PG&E Corporation, PG&E Corporation reinstated the payment of a regular quarterly dividend at an annual rate of $1.20 per share. As discussed below under "Liquidity and Financial Resources," on December 21, 2005 the Board of Directors of PG&E Corporation increased the annual dividend to $1.32 per share. For 2006, the CPUC has authorized the equity component of the Utility's capital structure to remain at 52% and has set a ROE for 2006 of 11.35%;

- *Stock Repurchases* – PG&E Corporation repurchased 61,139,700 shares of common stock for approximately $2.2 billion under accelerated share repurchase arrangements that increased both basic and diluted earnings per share, or EPS, by approximately $0.16 and $0.15, respectively, for 2005, as discussed below under "Liquidity and Financial Resources – Stock Repurchases." PG&E Corporation remains obligated to settle certain obligations under the accelerated share repurchase arrangement it entered in November 2005 either in cash or in shares, or a combination of the two, at PG&E Corporation's option. The settlement may have a material effect on PG&E Corporation's financial condition or results of operations;

- *Resolution of Claims for Energy Efficiency Incentives* – In October 2005, the CPUC approved a settlement agreement between the Utility and the CPUC's Office of Ratepayer Advocates, or the ORA, in which the parties agreed that the Utility would receive approximately $186 million for shareholder incentives for the successful implementation, over the years 1994 through 2001, of demand-side management, energy efficiency, and low-income energy efficiency programs. As discussed further in "Regulatory Matters" below, as a result of the CPUC's decision, the Utility recognized $186 million in electric and natural gas operating revenues in the fourth quarter of 2005. As a result of this settlement, the Utility will not record any future earnings due to shareholder incentives for these program years;

- *The Outcome of Regulatory Proceedings, including the 2007 General Rate Case* – On December 2, 2005, the Utility filed its 2007 General Rate Case, or GRC, application with the CPUC to determine the amount of authorized base revenues to be collected from customers to recover the Utility's basic business and operational costs for its electric and gas distribution and electric generation operations for the period 2007 through 2009. As compared to the projected authorized 2006 revenue requirements, the Utility's application requested increases in electric and gas

distribution revenue requirements of $481 million and $114 million, respectively, and an increase of $87 million related to generation expenses and administrative costs associated with electric procurement activities (see "Regulatory Matters" below);

- *The Success of the Utility's Strategy to Achieve Operational Excellence and Improved Customer Service* – During 2005, the Utility identified and has undertaken various initiatives to implement changes to its business processes and systems in an effort to provide better, faster and more cost-effective service to its customers. The Utility aims to achieve these goals in a three- to five-year period. The Utility's 2007 GRC application included a proposed mechanism to share with customers savings that may be achieved through implementation of these initiatives. In addition, the Utility's 2007 GRC application includes a proposal to replace the current incentive mechanism for reliability performance for the 2007–2009 period with a new customer service performance incentive mechanism. Under the proposal, the Utility would be rewarded or penalized up to $60 million per year to the extent that the Utility's actual performance exceeds or falls short of preset annual performance improvement targets over the 2007–2009 period (see "Regulatory Matters" below);

- *The Amount and Timing of Capital Expenditures* – The Utility has requested, in various proceedings including the GRC, that the CPUC approve various capital expenditures to fund (1) investments in transmission and distribution infrastructure needed to serve its customers (i.e., to extend the life of existing infrastructure, to replace existing infrastructure, and to add new infrastructure to meet load growth), (2) the installation of advanced meters, and (3) investment in new long-term generation resources, as may be authorized by the CPUC in accordance with the Utility's long-term electricity procurement plan. As discussed below under "Capital Expenditures," it is estimated that the Utility's capital expenditures will average approximately $2.5 billion annually from 2006 through 2010, resulting in a projected rate base of approximately $20.7 billion in 2010, reflecting a projected rate base growth of approximately 6.3% per year;

- *Actions Taken in Response to Rising Natural Gas Prices* – In response to rising natural gas prices during the fourth quarter of 2005, the CPUC permitted the Utility to implement additional hedging strategies to reduce the impact of higher prices on the Utility's residential and small commercial retail natural gas customers (referred to as core customers) and to reduce the impact of higher natural gas prices on the Utility's electric generation portfolio. For further discussion, see "Risk Management Activities" below. Although there are ratemaking mechanisms in place to recover the Utility's natural gas costs, the Utility's implementation of the CPUC-approved hedging strategies is subject to a compliance review. In addition, the CPUC approved the Utility's 10/20 Winter Gas Savings Program that offers residential and small business customers a 20% rebate for reducing their gas usage by 10% or more from January through March 2006. The Utility forecasts that these rebates will total approximately $150 million reducing cash inflows during the first four months of 2006. The Utility expects to recover this cash through rates during April through October 2006; and

- *The Accrual of Additional Liability for the Chromium Litigation and the Outcome of the CPUC's Investigation into the Utility's Billing and Collection Practices* – PG&E Corporation's and the Utility's net income for the year ended December 31, 2005 include an accrual of approximately $314 million reflecting the settlement of most of the claims in the litigation pending against the Utility involving allegations that exposure to chromium at or near some of the Utility's natural gas compressor stations caused personal injuries, wrongful deaths, or other injuries, referred to as the Chromium Litigation (discussed in Note 17 of the Notes to the Consolidated Financial Statements below) and an accrual for the remaining unresolved claims. PG&E Corporation and the Utility do not believe that the outcome of the remaining unresolved claims will have a material adverse affect on their future results of

operations or financial condition. PG&E Corporation and the Utility are unable to predict the outcome of the CPUC's investigation into the Utility's billing and collection practices as discussed below under "Regulatory Matters." In light of the recommended refunds and penalties, the outcome of the investigation could have a material adverse affect on their future results of operations or financial condition.

PG&E Corporation and the Utility aim for the Utility to earn no less than its authorized rate of return, generate strong cash flow, ensure adequate liquidity, and strengthen their credit ratings. The Utility's goals are to execute electric and gas procurement strategies that provide safe, cost-effective and environmentally sensitive Utility service, increase investment in the Utility's infrastructure, and improve customer service through implementation of specific initiatives to streamline business processes and deploy new technology. In addition to the key factors discussed above, PG&E Corporation's and the Utility's future results of operation and financial condition are subject to the risk factors discussed in detail in the section entitled "Risk Factors" below.

FORWARD-LOOKING STATEMENTS

This combined annual report and the letter to shareholders that accompanies it contain forward-looking statements that are necessarily subject to various risks and uncertainties, the realization or resolution of which are outside of management's control. These statements are based on current expectations and projections about future events, and assumptions regarding these events and management's knowledge of facts at the date of this report. These forward-looking statements are identified by words such as "assume," "expect," "intend," "plan," "project," "believe," "estimate," "predict," "anticipate," "aim," "may," "might," "should," "would," "could," "goal," "potential" and similar expressions. PG&E Corporation's and the Utility's results of operations and financial condition depend primarily on whether the Utility is able to operate its business within authorized revenue requirements, timely recover its authorized costs, and earn its authorized rate of return. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, are discussed in the section of this report entitled "Risk Factors." These factors include, but are not limited to:

Operating Environment

- How the Utility manages its responsibility to procure electric capacity and energy for its customers;
- The adequacy and price of natural gas supplies, and the ability of the Utility to manage and respond to the volatility of the natural gas market for its customers;
- Weather, storms, earthquakes, fires, floods, other natural disasters, explosions, accidents, mechanical breakdowns, acts of terrorism, and other events or hazards that affect demand for electricity or natural gas, result in power outages, reduce generating output, disrupt natural gas supply, cause damage to the Utility's assets or generating facilities, cause damage to the operations or assets of third parties on which the Utility relies, or subject the Utility to third party claims for damage or injury;
- Unanticipated population growth or decline, general economic and financial market conditions, changes in technology including the development of alternative energy sources, all of which may affect customer demand for natural gas or electricity;
- Whether the Utility is required to cease operations temporarily or permanently at its Diablo Canyon nuclear power plant, or Diablo Canyon, because the Utility is unable to increase its on-site spent nuclear fuel storage capacity, find another depositary for spent fuel, or timely complete the replacement of the steam generators, or because of mechanical breakdown, lack of nuclear fuel, environmental constraints, or for some other reason and the risk that the Utility may be required to purchase electricity from more expensive sources; and
- Whether the Utility is able to recognize the anticipated cost benefits and savings expected to result from its efforts to improve customer service through implementation of specific initiatives to streamline business processes and deploy new technology.

Legislative Actions and Regulatory Proceedings

- The outcome of the regulatory proceedings pending at the CPUC and the FERC discussed in "Regulatory Matters" below, and the impact of future ratemaking actions by the CPUC and the FERC;
- The impact of the recently enacted Energy Policy Act of 2005 which, among other provisions, repeals the Public Utility Holding Company Act of 1935 making electric utility industry consolidation more likely; expands the FERC's authority to review proposed mergers; changes the FERC regulatory scheme applicable to qualifying co-generation facilities, or QFs; authorizes the formation of an Electric Reliability Organization to be overseen by the FERC to establish electric reliability standards; and modifies certain other aspects of energy regulation and federal tax policies applicable to the Utility;
- The extent to which the CPUC or the FERC delays or denies recovery of the Utility's costs, including electricity or gas purchase costs, from customers due to a regulatory determination that such costs were not reasonable or prudent, or for other reasons, resulting in write-offs of regulatory assets;
- How the CPUC administers the capital structure, stand-alone dividend, and first priority conditions of the CPUC's past decisions permitting the establishment of holding companies for the California investor-owned electric utilities and the outcome of the CPUC's new rule-making proceeding concerning the relationship between the California investor-owned energy utilities and their holding companies and non-regulated affiliates, which may include (1) establishing reporting requirements for the allocation of capital between utilities and their non-regulated affiliates by the parent holding companies, and (2) changing the CPUC's affiliate transaction rules;
- Whether the Utility is determined to be in compliance with all applicable rules, tariffs and orders relating to electricity and natural gas utility operations, including tariffs related to the Utility's billing and collection practices as discussed below in "Regulatory Matters," and the extent to which a finding of non-compliance could result in customer refunds, penalties or other non-recoverable expenses, such as has been recommended with respect to the CPUC's investigation into the Utility's billing and collection practices; and
- Whether the Utility is required to incur material costs or capital expenditures or curtail or cease operations at affected facilities, including the Utility's natural gas compressor stations, to comply with existing and future environmental laws, regulations and policies.

Pending Litigation

- The outcome of pending litigation; and
- The timing and resolution of the pending appeal of the bankruptcy court order confirming the Utility's plan of reorganization under Chapter 11.

Municipalization and Bypass

- Continuing efforts by local public utilities to take over the Utility's distribution assets through exercise of their condemnation power or by duplication of the Utility's distribution assets or service, and other forms of municipalization that may result in stranded investment capital, decreased customer growth, loss of customer load and additional barriers to cost recovery; and
- The extent to which the Utility's distribution customers are permitted to switch between purchasing electricity from the Utility and from alternate energy service providers as direct access customers, and the extent to which cities, counties and others in the Utility's service territory begin directly serving the electricity needs of the Utility's customers, potentially resulting in stranded generating asset costs and non-recoverable procurement costs.

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 2005, 2004 and 2003.

(in millions)	Year ended December 31, 2005	2004	2003
Utility			
Electric operating revenues	$ 7,927	$ 7,867	$ 7,582
Natural gas operating revenues	3,777	3,213	2,856
Total operating revenues	11,704	11,080	10,438
Cost of electricity	2,410	2,770	2,319
Cost of natural gas	2,191	1,724	1,467
Operating and maintenance	3,399	2,842	2,935
Recognition of regulatory assets	—	(4,900)	—
Depreciation, amortization and decommissioning	1,734	1,494	1,218
Reorganization professional fees and expenses	—	6	160
Total operating expenses	9,734	3,936	8,099
Operating income	1,970	7,144	2,339
Interest income	76	50	53
Interest expense	(554)	(667)	(953)
Other expense, net[1]	—	(5)	(9)
Income before income taxes	1,492	6,522	1,430
Income tax provision	574	2,561	528
Income before cumulative effect of a change in accounting principle	918	3,961	902
Cumulative effect of a change in accounting principle	—	—	(1)
Income available for common stock	$ 918	$ 3,961	$ 901
PG&E Corporation, Eliminations and Other[2][3]			
Operating revenues	$ (1)	$ —	$ (3)
Operating expenses	(1)	26	(7)
Operating income (loss)	—	(26)	4
Interest income	4	13	9
Interest expense	(29)	(130)	(194)
Other expense, net[1]	(19)	(93)	—
Loss before income taxes	(44)	(236)	(181)
Income tax benefit	(30)	(95)	(70)
Income (loss) from continuing operations	(14)	(141)	(111)
Discontinued operations	13	684	(365)
Cumulative effect of changes in accounting principles	—	—	(5)
Net income (loss)	$ (1)	$ 543	$ (481)
Consolidated Total[3]			
Operating revenues	$11,703	$11,080	$10,435
Operating expenses	9,733	3,962	8,092
Operating income	1,970	7,118	2,343
Interest income	80	63	62
Interest expense	(583)	(797)	(1,147)
Other expenses, net[1]	(19)	(98)	(9)
Income before income taxes	1,448	6,286	1,249
Income tax provision	544	2,466	458
Income from continuing operations	904	3,820	791
Discontinued operations	13	684	(365)
Cumulative effect of changes in accounting principles	—	—	(6)
Net income	$ 917	$ 4,504	$ 420

(1) Includes preferred dividend requirement as other expense.

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

(3) Operating results of NEGT are reflected as discontinued operations. See Note 7 of the Notes to the Consolidated Financial Statements for further discussion.

UTILITY

Under cost of service ratemaking, the Utility's rates are determined based on its costs of service and are generally adjusted periodically to reflect differences between actual sales or demand compared to forecasted sales or demand used in setting rates. The CPUC and the FERC determine the amount of "revenue requirements" the Utility is authorized to collect from its customers to recover the Utility's operating and capital costs. Revenue requirements are primarily determined based on the Utility's forecast of future costs, including the costs of purchasing electricity and natural gas on behalf of the Utility's customers.

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

The Utility's electricity and natural gas distribution and electric generation rates reflect the sum of individual revenue requirement components authorized by the CPUC. Changes in any individual revenue requirement affect customers' rates and could affect the Utility's revenues. Pending regulatory proceedings that could result in rate changes and affect the Utility's revenues are discussed below under "Regulatory Matters." Each year the Utility requests the CPUC to authorize an adjustment to electric and gas rates effective on the first day of the following year to (1) reflect over- and under- collections in the Utility's major electric and gas balancing accounts (including electricity procurement), and (2) consolidate various other electricity and gas revenue requirement changes authorized by the CPUC or the FERC. Balances in all accounts authorized for recovery are subject to review, verification, and adjustment, if necessary, by the CPUC.

The timing of the CPUC and other regulatory decisions affect when the Utility is able to record the authorized revenues. As discussed below, because the CPUC's decision in the GRC covering the period 2003–2006 was not issued until May 2004, the Utility recorded approximately $52 million in revenues related to 2003 in 2004. In the 2007 GRC, the Utility requested the CPUC to approve an increase in 2007 electric and gas revenue requirements of $481 million and $114 million, respectively, over the amount authorized for 2006 in the last GRC. The Utility has requested the CPUC to issue a decision in the 2007 GRC before the end of 2006 so the Utility can begin to record any authorized changes to revenues on January 1, 2007. The Utility has also requested attrition adjustments for 2008 and 2009.

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

The following presents the Utility's operating results for 2005, 2004 and 2003.

Electric Operating Revenues

Beginning January 1, 1998, electricity rates were frozen as required by the California electric industry restructuring law. In 2001, in response to the California energy crisis, the CPUC increased frozen rates by imposing fixed surcharges which the Utility collected through December 31, 2003. As a result of the Settlement Agreement and various CPUC decisions, the Utility's electricity rates beginning January 1, 2004 were no longer frozen and are determined based on its costs of service.

As discussed below under "2007 GRC," differences between the authorized revenue requirements and amounts collected by the Utility from customers in rates are tracked in regulatory balancing accounts and are reflected in miscellaneous revenues in the table below.

The Utility relies on electricity provided under long-term electricity procurement contracts entered into in 2001 through December 2002 with the California Department of Water Resources, or the DWR, to meet a material portion of its customers' demand. Revenues collected on behalf of the DWR and the DWR's related costs are not included in the Utility's Consolidated Statements of Income, reflecting the Utility's role as a billing and collection agent for the DWR's sales to the Utility's customers. Previously, under the frozen rate structure, increases in the revenues passed through to the DWR decreased the Utility's revenues. Starting in 2004, the Utility's electric operating revenues are based on an aggregation of individual rate components, including base revenue requirements and electricity procurement costs, among others. Changes in the DWR's revenue requirements will not affect the Utility's revenues. Although the Utility is permitted to pass through the DWR charges to customers, any changes in the amount of DWR charges that the Utility's customers are required to pay can affect regulatory willingness to increase overall rates to permit the Utility to recover its own costs. As overall rates rise or decline, there may be changes regarding the risk of regulatory disallowance of costs.

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

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

(in millions)	2005	2004	2003
Electric revenues	$ 9,648	$ 9,600	$10,043
DWR pass-through revenue	(1,699)	(1,933)	(2,243)
Subtotal	7,949	7,667	7,800
Miscellaneous	(22)	200	(218)
Total electric operating revenues	$ 7,927	$ 7,867	$ 7,582
Total electricity sales (in GWh)[1]	81,626	83,096	80,152

(1) Includes DWR electricity sales.

The Utility's electric operating revenues increased in 2005 by approximately $60 million, or approximately 1% compared to 2004 mainly due to the following factors:

- Authorized yearly adjustments to the Utility's base revenues, or attrition revenues as authorized in the 2003 GRC and revenues authorized in the 2004 cost of capital proceeding resulted in an increase in electric operating revenues of approximately $90 million for the year ended December 31, 2005, as compared to 2004;
- The Utility's collection of the dedicated rate component, or DRC, charge and revenue requirements associated with the Energy Recovery Bond Balancing Account, or ERBBA, resulted in an increase of approximately $390 million in electric operating revenue in 2005, with no similar amount in 2004 (see further discussion in Note 6 of the Notes to the Consolidated Financial Statements);
- The resolution of claims made in the Utility's Annual Earnings Assessment Proceeding, or AEAP, for shareholder incentives related to energy efficiency and other public purpose programs covering past program years 1994–2001, resulted in an increase of approximately $160 million in electric revenues in 2005, with no similar amount in 2004 (see further discussion in "Regulatory Matters");
- The settlement entered in the CPUC proceeding related to the Electric Restructuring Costs Account resulted in an increase of approximately $80 million in electric operating revenues in 2005, with no similar amount in 2004. The settlement agreement authorized the Utility to collect revenue requirements to recover the distribution-related electric industry restructuring costs through rates charged to certain of the Utility's customers during 2005;

- Electric operating revenues increased by approximately $70 million primarily as a result of certain regulatory proceedings resulting in refunds in revenue requirements to customers in 2004, with no similar amount in 2005;
- An increase of approximately $100 million reflecting the recognition of Self-Generation Incentive Program revenues as authorized in the 2005 Annual Electric True-up, or AET, that previously had no specific revenue recovery mechanism, with no similar amount in 2004; and
- Miscellaneous other electric operating revenues, including revenues associated with public purpose programs and advanced metering and demand response programs, increased by approximately $140 million in 2005 compared to 2004.

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

- Electric operating revenues decreased approximately $530 million compared to 2004, primarily due to lower electricity procurement and transmission costs which are passed through to customers; and
- Electric operating revenues decreased approximately $435 million as a result of a decrease in the revenue requirement associated with the Settlement Regulatory Asset. As a result of the refinancing of the after-tax portion of the Settlement Regulatory Asset on February 10, 2005 through issuance of the first series of ERBs the Utility was no longer authorized to collect this revenue requirement (see further discussion in Note 6 of the Notes to the Consolidated Financial Statements).

The Utility's electric operating revenues increased in 2004 by approximately $285 million, or approximately 4%, compared to 2003 due to the following factors:

- The CPUC authorization for the Utility to collect the revenue requirements associated with the Settlement Regulatory Asset and the other regulatory assets provided under the Settlement Agreement resulted in an electric operating revenue increase of approximately $490 million during 2004, compared to 2003;
- The approval of the Utility's 2003 GRC in May 2004 resulted in an electric operating revenue increase of approximately $100 million;
- Electric transmission revenues increased by approximately $400 million in 2004 compared to 2003 primarily due to an increase in recoverable reliability must run, or RMR, costs and an increase in at-risk transmission access revenues; and
- The remaining increases in the Utility's electric operating revenues were due to increases of approximately $170 million in the Utility's authorized revenue requirements for procurement and miscellaneous other electric revenues in 2004 compared to 2003.

Partially offsetting the increase in electric operating revenues between 2003 and 2004 was the absence of surcharge revenues in 2004 as a result of the return to cost of service ratemaking in 2004. The Utility collected $875 million in surcharge revenues in 2003.

The Utility's electric operating revenues are expected to increase in 2006 primarily due to an attrition adjustment authorized in the 2003 GRC decision. Also, as discussed above, the Utility's future electric operating revenues are expected to increase in the period 2007 through 2009 as a result of the 2007 GRC. (For further discussion see "2007 GRC" under "Regulatory Matters" of the MD&A). In addition, revenues associated with the collection of the DRC charge are scheduled to continue through 2012 when the ERBs mature. The Utility also expects to be able to pass its electricity commodity costs through to its customers, which will also have an impact on future revenues.

Cost of Electricity

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

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

(in millions)	2005	2004	2003
Cost of purchased power	$ 2,706	$ 2,816	$ 2,449
Proceeds from surplus sales allocated to the Utility	(478)	(192)	(247)
Fuel used in own generation	182	146	117
Total net cost of electricity	$ 2,410	$ 2,770	$ 2,319
Average cost of purchased power per GWh	$ 0.079	$ 0.082	$ 0.076
Total purchased power (GWh)	34,203	34,525	32,249

In 2005, the Utility produced more electricity from its own generation facilities which reduced the amount of electricity the Utility was required to purchase for its customers. During 2005, Diablo Canyon had a refueling outage for 41 days as compared to 2004 when there were two refueling outages totaling approximately 129.5 days, which required the Utility to purchase more replacement power. In addition, as of January 1, 2005, the Utility was no longer required to procure electricity for customers of the Western Area Power Administration. As a result, the Utility's cost of electricity decreased in 2005 as compared to 2004.

In 2005, the Utility's cost of electricity decreased by approximately $360 million, or 13%, as compared to 2004, mainly due to the following factors:

- The increase in surplus conditions created by increased electricity production from the Utility's hydroelectric generation facilities due to above average rainfall during 2005 resulted in an increase in proceeds from surplus sales allocated to the Utility of $286 million in 2005, as compared to 2004, which resulted in a corresponding decrease in the cost of electricity; and
- The decrease in total purchased power of 322 Gigawatt hours, or GWh, and the decrease in the average cost of purchased power of $0.003 per GWh in 2005, as compared to 2004, resulted in a decrease of approximately $110 million in the cost of purchased power.

In 2004, the Utility's cost of electricity increased by approximately $451 million, or 19%, as compared to 2003 mainly due to the following factors:

- The increase in total purchased power of 2,276 GWh and the increase in the average cost of purchased power of $0.006 per GWh, in 2004 as compared to 2003 resulted in an increase of approximately $367 million in the cost of purchased power; and
- The cost of electricity increased by approximately $84 million in 2004 as compared to 2003 as a result of a decrease in the proceeds from surplus sales allocated to the Utility in 2004 and an increase in the amount of fuel used in the Utility's owned generation.

The Utility's cost of electricity in 2006 will depend upon electricity prices, the duration of the Diablo Canyon refueling outage, and the change in customer usage which will directly impact the Utility's net open position. (See the "Risk Management Activities" section of this MD&A).

Natural Gas Operating Revenues

The Utility sells natural gas and natural gas transportation services to its customers. The Utility's transportation system transports gas throughout California to the Utility's distribution system, which, in turn, delivers gas to end-use customers. The Utility's natural gas customers consist of two categories: core and non-core customers. The core customer class is comprised mainly of residential and smaller commercial natural gas customers. The non-core customer class is comprised of industrial and larger commercial natural gas customers. The Utility provides natural gas delivery services to all core and non-core customers connected to the Utility's system in its service territory. Core customers can purchase natural gas from alternate energy service providers or can elect to have the Utility provide both delivery service and natural gas supply. When the Utility provides both supply and delivery, the Utility refers to the service as natural gas bundled service. In 2005, core customers represented over 99% of the Utility's total customers and approximately 40% of its total natural gas deliveries, while non-core customers comprised less than 1% of the Utility's total customers and approximately 60% of its total natural gas deliveries.

The Utility's natural gas transportation and storage rates for the 2005–2007 period have been determined by a December 2004 CPUC decision which approved the Gas Accord III Settlement Agreement reached among the Utility and other interested parties. Under the Gas Accord III Settlement Agreement, the Utility agreed to not have a

balancing account for the over-collections or under-collections of natural gas transportation or storage revenues, thus assuming the risk of not recovering its full natural gas transportation and storage costs that have not been contracted for under fixed reservation charges with its core customers. (See discussion below under "Risk Management Activities – Transportation and Storage").

There is an incentive mechanism for recovery of natural gas procurement costs for the Utility's core customers called the Core Procurement Incentive Mechanism, or CPIM, which is used to determine the reasonableness of the Utility's costs of purchasing natural gas for its customers. Under the CPIM, the Utility's purchase costs for a 12-month period are compared to an aggregate market-based benchmark based on a weighted average of published monthly and daily natural gas price indices at the points where the Utility typically purchases natural gas. Costs that fall within a tolerance band, which is 99% to 102% of the benchmark, are considered reasonable and are fully recovered in customers' rates. One-half of the costs above 102% of the benchmark are recoverable in customers' rates, and the Utility's customers receive in their rates three-fourths of any savings resulting from the Utility's cost of natural gas that is less than 99% of the benchmark. The shareholder award is capped at the lower of 1.5% of total natural gas commodity costs or $25 million. While this cost recovery mechanism remains in place, changes in the price of natural gas are not expected to materially impact net income.

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

(in millions)	2005	2004	2003
Bundled natural gas revenues	$3,539	$2,943	$2,572
Transportation service-only revenues	238	270	284
Total natural gas operating revenues	$3,777	$3,213	$2,856
Average bundled revenue per Mcf of natural gas sold	$13.05	$10.51	$ 9.22
Total bundled natural gas sales (in millions of Mcf)	271	280	279

In 2005, the Utility's natural gas operating revenues increased by approximately $564 million, or 18%, compared to 2004. The increase in natural gas operating revenues was primarily due to the following factors:

- Excluding the impact of the 2003 GRC decision, the 2004 and 2005 cost of capital proceedings, and the Utility's AEAP discussed below, bundled natural gas operating revenues increased by approximately $580 million, or 20%, in 2005 as compared to 2004. This increase was primarily due to an increase in the cost of natural gas, which the Utility is permitted by the CPUC to pass on to its customers through higher rates, resulting in an increase in the average bundled revenue per thousand cubic feet, or Mcf, of natural gas sold of approximately $2.48 per Mcf, or 24%, partially offset by a decrease in volume of approximately 9 Mcf, or 3%;
- Authorized yearly adjustments to the Utility's base revenues, or attrition revenues, as authorized in the 2003 GRC and revenues authorized in the 2004 cost of capital proceeding resulted in an increase in natural gas operating revenues of approximately $42 million in 2005 as compared to 2004; and
- The resolution of the Utility's claims made in the AEAP for shareholder incentives related to energy efficiency and other public purpose programs covering past program years 1994–2001, resulted in an increase of approximately $26 million in gas revenues in 2005, with no similar amount in 2004. (See further discussion in "Regulatory Matters").

These increases were partially offset by the following decreases:

- The approval of the 2003 GRC in May 2004 resulted in the Utility recording approximately $52 million in revenues related to 2003 in 2004 with no comparable amount in 2005; and
- Transportation service-only revenues decreased by approximately $32 million, or 12%, in 2005 as compared to 2004, primarily as a result of a decrease in rates.

In 2004, the Utility's natural gas operating revenues increased by approximately $357 million, or 13%, compared to 2003. The increase in natural gas operating revenues was primarily due to the following factors:

- Bundled natural gas revenues (excluding the effects of the 2003 GRC decision discussed below) increased by approximately $250 million, or 10%, in 2004 compared to 2003, mainly due to a higher cost of natural gas, which the Utility is permitted by the CPUC to pass on to its customers through higher rates. The average bundled revenue per

Mcf of natural gas sold in 2004 (excluding the effects of the 2003 GRC decision discussed below) increased by approximately $0.86, or 9%, as compared to 2003; and

- The approval of the 2003 GRC resulted in an increase in natural gas revenues of approximately $121 million (consisting of a 2004 portion of $69 million and a 2003 portion of $52 million) in 2004 compared to 2003.

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

Cost of Natural Gas

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

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

(in millions)	2005	2004	2003
Cost of natural gas sold	$2,051	$1,591	$1,336
Cost of natural gas transportation	140	133	131
Total cost of natural gas	$2,191	$1,724	$1,467
Average cost per Mcf of natural gas sold	$ 7.57	$ 5.68	$ 4.79
Total natural gas sold (in millions of Mcf)	271	280	279

In 2005, the Utility's total cost of natural gas increased by approximately $467 million, or 27%, as compared to 2004, primarily due to an increase in the average market price of natural gas purchased of approximately $1.89 per Mcf, or 33%, partially offset by a decrease in volume of 9 Mcf, or 3%.

In 2004, the Utility's total cost of natural gas increased approximately $257 million, or 18%, as compared to 2003, primarily due to an increase in the average market price of natural gas purchased of approximately $0.89 per Mcf.

The Utility's cost of natural gas sold in 2006 will be primarily affected by the prevailing costs of natural gas, which are determined by North American regions that supply the Utility. In October 2005, the CPUC granted the Utility authority to execute hedges on behalf of the Utility's core gas customers, and to record the costs and any payouts of such hedges in a separate balancing account, outside of CPIM. This action was undertaken because of rapidly rising natural gas prices in the wake of Hurricanes Katrina and Rita. The CPUC's decision authorizes enhanced hedging activity on behalf of core customers for the winter of 2005–2006 and for two subsequent winters. The Utility also has agreed to forego a shareholder award under the CPIM for the 2004–2005 CPIM year. (For further discussion see "Risk Management" below). The cost of gas will also be affected by customer demand.

Operating and Maintenance

Operating and maintenance expenses consist mainly of the Utility's costs to operate and maintain its electricity and natural gas facilities, customer accounts and service expenses, public purpose program expenses, and administrative and general expenses. Generally, these expenses are recoverable from customers through rates.

During 2005, the Utility's operating and maintenance expenses increased by approximately $557 million, or 20%, compared to 2004, mainly due to the following factors:

- An increase of approximately $40 million associated with the reassessment of the estimated cost of environmental remediation related to the Topock and Hinkley gas compressor stations (see "Environmental Matters" in Note 17 of the Notes to the Consolidated Financial Statements for further discussion);
- An increase of approximately $110 million related to administration expenses for low-income customer assistance programs and community outreach programs;
- An increase of approximately $100 million reflecting recognition of Self-Generation Incentive Program expenses in 2005 as authorized in the 2005 AET that were deferred in prior periods as there was no specific revenue recovery mechanism in place (see related revenues in "Electric Operating Revenues");
- An increase of approximately $154 million reflecting a settlement related to the Chromium Litigation and an accrual for the remaining unresolved claims (see further discussion in "Legal Matters");

- An increase of approximately $55 million related to outside consulting, contract and legal expense and various programs and initiatives including strategies to achieve operational excellence and improved customer service;
- An increase of approximately $60 million primarily related to gas transportation operations charges mainly due to rate increases for pipeline demand and transportation; and
- An increase of approximately $25 million primarily related to property taxes mainly due to higher assessments in 2005.

Partially offsetting these increases is the following decrease:

- A decrease of approximately $50 million in operating and maintenance expenses at Diablo Canyon in 2005, as compared to 2004, primarily reflecting costs associated with the longer scheduled refueling outage in 2004 as compared to 2005.

During 2004, the Utility's operating and maintenance expenses decreased by approximately $93 million, or 3%, compared to 2003. This decrease is primarily due to the establishment of a regulatory asset of approximately $50 million in 2004 related to distribution-related electric industry restructuring costs incurred during the period from 1999 through 2002 that were previously not considered probable of recovery. During 2004, the CPUC approved a settlement agreement that permits recovery of a portion of these costs.

The Utility's operating and maintenance expenses in 2006 are expected to increase as a result of increased expenses related to various programs and initiatives including public purpose programs and strategies to achieve operational excellence and improved customer service. (See "Overview" section in this MD&A for further discussion). In addition, operating and maintenance expenses are influenced by wage inflation, benefits, property taxes, timing and length of Diablo Canyon refueling outages, environmental remediation costs that cannot be recovered through rates, legal costs, and various other administrative and general expenses.

Recognition of Regulatory Assets

In light of the satisfaction of various conditions to the implementation of the Utility's plan of reorganization, the Utility recorded the regulatory assets provided for under the Settlement Agreement in the first quarter of 2004. This resulted in the recognition of a one-time non-cash, pre-tax gain of $3.7 billion for the Settlement Regulatory Asset and $1.2 billion for the Utility retained generation regulatory assets, for a total after-tax gain of $2.9 billion. See Note 3 of the Notes to the Consolidated Financial Statements for further discussion.

Depreciation, Amortization and Decommissioning

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

In 2005 the Utility's depreciation, amortization and decommissioning expenses increased by approximately $240 million, or 16%, compared to 2004, primarily as a result of the following factors:

- The Utility recorded approximately $202 million in 2005 for amortization of the ERB regulatory asset with no similar amount in 2004;
- As a result of the 2003 GRC decision in May 2004 authorizing lower depreciation rates, the Utility recorded an approximately $38 million decrease to depreciation expense related to 2003 in 2004 with no similar reduction in 2005; and
- Depreciation expense increased by approximately $32 million as a result of plant additions in 2005 as compared to 2004.

Partially offsetting these increases were the following decreases:

- Amortization of the regulatory asset related to rate recovery bonds, or RRBs, decreased by approximately $20 million in 2005, as compared to 2004. The Utility's regulatory asset related to the RRBs is amortized simultaneously with the amortization of the RRB liability, and is expected to be recovered by the end of 2007. This decrease is mainly due to the declining balance of the RRB liability; and
- Amortization of the Settlement Regulatory Asset decreased by approximately $10 million in 2005 as compared to the same period in 2004. This decrease is mainly due to the

refinancing of the Settlement Regulatory Asset following the first and second series of ERBs on February 10, 2005 and November 9, 2005, respectively.

In 2004, the Utility's depreciation, amortization and decommissioning expenses increased by approximately $276 million, or 23%, compared to 2003, primarily due to an increase of approximately $233 million related to the amortization of the Settlement Regulatory Asset. The remainder of the increase is primarily due to an increase in the Utility's plant assets.

The Utility's depreciation, amortization and decommissioning expenses in 2006 are expected to increase as a result of an overall increase in capital expenditures.

Interest Income

In 2005, the Utility's interest income, including reorganization interest income, increased by approximately $26 million, or 52%, compared to 2004, primarily due to a higher balance and rate of return on short-term investments in 2005 as compared to 2004.

In 2004, the Utility's interest income, including reorganization interest income, decreased by approximately $3 million, or 6%, compared to 2003, primarily due to lower average interest rates on the Utility's short-term investments.

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

The Utility's interest income in 2006 will be primarily affected by interest rate levels.

Interest Expense

In 2005, the Utility's interest expense decreased by approximately $113 million, or 17%, compared to 2004, primarily due to a decrease of approximately $109 million in net interest costs on energy supplier claims and energy crisis interest expense incurred in 2004 prior to the Utility's emergence from Chapter 11. The ERBBA tariff provides that reasonable net interest costs on energy supplier claims subsequent to the issuance of the first series of ERBs (February 10, 2005) may be recovered through the ERBBA account. (See "Regulatory Matters" below.) As a result, the net interest expense decreased from 2004.

PERF (a wholly owned subsidiary of the Utility) issued the first series of ERBs on February 10, 2005, and the second series of ERBs on November 9, 2005. The proceeds of the issuances were used by the Utility to retire outstanding long-term debt and preferred shares, repurchase common shares, and rebalance the capital structure. The net additional interest expense of approximately $76 million resulting from the ERB refinancing was offset by lower interest on both the RRBs of approximately $18 million and short term borrowings of approximately $56 million due to lower amount of debt outstanding.

In 2004, the Utility's interest expense decreased by approximately $286 million, or 30%, compared to 2003 mainly due to a lower average amount of unpaid debt accruing interest and a lower weighted average interest rate on debt outstanding during 2004 compared to 2003. As a result of this interest savings, the CPUC reduced the Utility's authorized cost of capital revenue requirement in 2004. (See the "Regulatory Matters" section of this MD&A.)

The Utility's interest expense in 2006 is expected to increase due to an overall increase in rate base, which will require additional financing.

Income Tax Expense

In 2005, the Utility's tax expense decreased by approximately $2.0 billion, or 78%, compared to 2004, mainly due to a decrease in pre-tax income of approximately $5.0 billion for 2005. This decrease is primarily the result of the recognition of regulatory assets associated with the Settlement Agreement in 2004 with no similar amount recognized in 2005. The effective tax rate for the year ended December 31, 2005 decreased by 1.3 percentage points from 2004. This decrease is mainly due to increased investment tax credits in 2005.

In 2004, the Utility's income tax expense increased by approximately $2.0 billion, or 385%, as compared to 2003, mainly due to an increase in pre-tax income of approximately $5.1 billion for the year ended December 31, 2004, primarily as a result of the recognition of regulatory assets associated with the Settlement Agreement, as compared to the same period in 2003. This increase was partially offset by the recognition of tax regulatory assets established upon

receipt of the Utility's 2003 GRC decision. The effective tax rate for the year ended December 31, 2004 increased by 2.9 percentage points from 2003. This increase is mainly due to increases in the effect of regulatory treatment of depreciation differences and lower tax credit amortization in 2004.

PG&E CORPORATION, ELIMINATIONS AND OTHERS

Operating Revenues and Expenses

PG&E Corporation's revenues consist mainly of billings to its affiliates for services rendered, all of which are eliminated in consolidation. PG&E Corporation's operating expenses consist mainly of employee compensation and payments to third parties for goods and services. Generally, PG&E Corporation's operating expenses are allocated to affiliates. These allocations are made without mark-up. Operating expenses allocated to affiliates are eliminated in consolidation.

The decrease in operating expenses of $27 million, or 104%, in 2005, as compared to 2004, was primarily due to an increase in expenses allocated to affiliates.

The increase in operating expenses of $33 million, or 471%, in 2004, as compared to 2003, was primarily due to the absence of entries in 2004 to eliminate the cost of natural gas and electricity expenses provided by NEGT to the Utility after PG&E Corporation's deconsolidation of NEGT effective July 7, 2003. A reduction in general and administrative expenses in 2004 compared to 2003 partly offset this increase.

Interest Expense

PG&E Corporation's interest expense is not allocated to its affiliates.

The decrease of $101 million, or 78%, in interest expense in 2005, as compared to 2004, was primarily due to the redemption of PG&E Corporation's 6 7/8% Senior Secured Notes due 2008, or Senior Secured Notes, on November 15, 2004.

In 2004, PG&E Corporation's interest expense decreased by approximately $64 million, or 33%, compared to 2003 due to a reduction in principal debt amount outstanding and lower interest rates in 2004 compared to 2003, as well as a write-off of approximately $89 million of unamortized loan fees, loan discount, and prepayment fees associated with the repayment in July 2003 of approximately $735 million of principal and interest under PG&E Corporation's then-existing credit agreement. This decrease in interest expense between 2003 and 2004 was partly offset by a redemption premium of approximately $51 million and a charge due to the write-off of approximately $15 million of unamortized loan fees associated with the redemption of the Senior Secured Notes.

Other Expense

The decrease of $74 million, or 80%, in other expense in 2005 as compared to 2004, was primarily due to a decrease in the pre-tax charge to earnings, related to the change in market value of non-cumulative dividend participation rights included within PG&E Corporation's $280 million of 9.50% Convertible Subordinated Notes due 2010, or Convertible Subordinated Notes.

PG&E Corporation's other expense increased by approximately $93 million in 2004 compared to 2003. The increase was primarily due to a pre-tax charge to earnings, related to the change in market value of non-cumulative dividend participation rights included within the Convertible Subordinated Notes.

Discontinued Operations

During the third quarter of 2005, PG&E Corporation received additional information from NEGT regarding income to be included in PG&E Corporation's 2004 federal income tax return. This information was incorporated in the 2004 tax return, which was filed with the Internal Revenue Service, or IRS, in September 2005. As a result, PG&E Corporation's 2004 federal income tax liability was reduced by approximately $19 million. In addition, NEGT provided additional information with respect to amounts previously included in PG&E Corporation's 2003 federal income tax return. This change resulted in PG&E Corporation's 2003 federal income tax liability increasing by approximately $6 million. These two adjustments, netting to $13 million, were recognized in income from discontinued operations in 2005.

Effective July 8, 2003, which is the date NEGT filed a voluntary petition for relief under Chapter 11, NEGT and its subsidiaries were no longer consolidated by PG&E Corporation in its Consolidated Financial Statements. Accordingly, PG&E Corporation has reflected the loss from operations of NEGT through July 7, 2003 as discontinued operations in its Consolidated Statements of Income. On October 29, 2004, NEGT's plan of reorganization became

effective, at which time NEGT emerged from Chapter 11 and PG&E Corporation's equity ownership in NEGT was cancelled. On the effective date, PG&E Corporation reversed its negative investment in NEGT and also reversed net deferred income tax assets of approximately $428 million and a charge of approximately $120 million ($77 million, after tax), in accumulated other comprehensive income, related to NEGT. The resulting net gain has been offset by the $30 million payment made by PG&E Corporation to NEGT pursuant to the parties' settlement of certain tax-related litigation and other adjustments to NEGT-related liabilities. A summary of the effect on the quarter and year ended December 31, 2004 earnings from discontinued operations is as follows:

(in millions)	
Investment in NEGT	$1,208
Accumulated other comprehensive income	(120)
Cash paid pursuant to settlement of tax related litigation	(30)
Tax effect	(374)
Gain on disposal of NEGT, net of tax	$ 684

At December 31, 2004, PG&E Corporation's Consolidated Balance Sheet included approximately $138 million in income tax liabilities (including $86 million in current income taxes payable) and approximately $25 million of other net liabilities related to NEGT. At December 31, 2005, PG&E Corporation's Consolidated Balance Sheet included approximately $89 million of current income taxes payable and approximately $24 million of other net liabilities related to NEGT. Until PG&E Corporation reaches final settlement of these obligations, it will continue to disclose fluctuations in these estimated liabilities in discontinued operations. Beginning on the effective date of NEGT's plan of reorganization, PG&E Corporation no longer includes NEGT or its subsidiaries in its consolidated income tax returns.

LIQUIDITY AND FINANCIAL RESOURCES

OVERVIEW

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

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

At December 31, 2005, PG&E Corporation and its subsidiaries had consolidated cash and cash equivalents of approximately $0.7 billion, and restricted cash of approximately $1.5 billion. PG&E Corporation and the Utility maintain separate bank accounts. At December 31, 2005, PG&E Corporation on a stand-alone basis had cash and cash equivalents of approximately $250 million; the Utility had cash and cash equivalents of approximately $463 million, and restricted cash of approximately $1.5 billion. The Utility's restricted cash includes amounts deposited in escrow related to the remaining disputed Chapter 11 claims, collateral required by the Independent System Operator, or ISO, and deposits under certain third-party agreements. PG&E Corporation and the Utility primarily invest their cash in money market funds and in short-term obligations of the U.S. Government and its agencies.

The Utility seeks to maintain or strengthen its credit ratings to provide liquidity through efficient access to financial and trade credit, and to reduce financing costs. As of February 1, 2006, the credit ratings on various financing instruments from Moody's Investors Service, or Moody's, and Standard & Poor's Ratings Service, or S&P, were as follows:

	Moody's	S&P
Utility		
Corporate credit rating	Baa1	BBB
Senior unsecured debt	Baa1	BBB
Pollution control bonds backed by bond insurance	Aaa	AAA
Pollution control bonds backed by letters of credit	–(1)	AA-/A-1+
Credit facility	Baa1	BBB
Preferred stock	Baa3	BB+
Commercial paper program	P-2	A-2
PG&E Funding LLC		
Rate reduction bonds	Aaa	AAA
PG&E Energy Recovery Funding LLC		
Energy recovery bonds	Aaa	AAA
PG&E Corporation		
Corporate credit rating	Baa3	–(2)
Credit facility	Baa3	–(2)

(1) Moody's has not assigned a rating to the Utility's pollution control bonds backed by letters of credit.

(2) S&P has not assigned a rating to PG&E Corporation.

Moody's and S&P are nationally recognized statistical rating organizations. These ratings may be subject to revision or withdrawal at any time by the assigning rating organization and each rating should be evaluated independently of any other rating. A security rating is not a recommendation to buy, sell or hold securities.

As of December 31, 2005, PG&E Corporation and the Utility have credit facilities totaling $200 million and $2 billion, respectively, with remaining borrowing capacity on these credit facilities of $200 million and $1.5 billion, respectively. In January 2006, the Utility established a $1 billion commercial paper program. Because the Utility will have same-day access to liquidity through the commercial paper program, it will no longer need to hold material levels of unrestricted cash.

PG&E Corporation plans to target a minimum cash liquidity reserve of $40 million, and plans to maintain a minimum of $100 million of unused borrowing capacity on its revolving credit facility for contingencies. The Utility plans to maintain a minimum of $700 million of unused short-term borrowing capacity available to meet unforeseen contingencies during 2006. The Utility will periodically re-evaluate this level of reserves.

The Utility anticipates issuing approximately $3 billion of long-term debt, subject to CPUC authorization, over the next five years to fund capital expenditures and scheduled debt repayments.

During 2005, the Utility used cash (including the ERB proceeds) in excess of amounts needed for operations, debt service, capital expenditures, and preferred stock requirements to pay a quarterly common stock dividend and to repurchase approximately $1.9 billion of common stock from PG&E Corporation.

In turn, PG&E Corporation used the cash received from the Utility to recommence the payment of a regular quarterly dividend and to repurchase common stock from shareholders. PG&E Corporation anticipates using between $100 million to $200 million during 2006 to repurchase shares using cash distributions received from the Utility, in addition to shares it expects to repurchase to offset option exercises. PG&E Corporation anticipates over the next five years it may issue shares (possibly through a combination of employee plans and direct issuance to the market) and contribute the proceeds to the Utility to fund capital expenditures in years of higher capital expenditures while it may repurchase shares in years with lower capital expenditures. Over the five-year period, these share issuances and repurchases are expected to approximately offset each other and result in no net issuance of equity.

DIVIDENDS

PG&E Corporation and the Utility did not declare or pay a dividend during the Utility's Chapter 11 proceeding as the Utility was prohibited from paying any common or preferred stock dividends without bankruptcy court approval and certain covenants in PG&E Corporation's Senior Secured Notes restricted the circumstances in which such a dividend could be declared or paid. With the Utility's emergence from Chapter 11 on April 12, 2004, the Utility resumed the payment of preferred stock dividends. The Utility reinstated the payment of a regular quarterly common stock dividend to PG&E Corporation in January 2005, upon the achievement of the 52% equity ratio targeted in the Settlement Agreement.

In October 2004, the Boards of Directors of PG&E Corporation and the Utility approved dividend policies that 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 the necessity to issue new equity unless PG&E Corporation's or the Utility's capital expenditure requirements are growing rapidly and PG&E Corporation or the Utility can issue equity at reasonable cost and terms; and
- Sustainability: Avoid reduction or suspension of the dividend despite fluctuations in financial performance except in extreme and unforeseen circumstances.

The target dividend payout ratio range of 50% to 70% of earnings was based on an analysis of dividend payout ratios of comparable companies. Dividends are expected to remain in the lower end of PG&E Corporation's target payout range in order to ensure that equity funding is readily available to support capital investment needs. The Boards of Directors retain authority to change their common stock dividend policy and dividend payout ratio at any time, especially if unexpected events occur that would change the Board's view as to the prudent level of cash conservation. No dividend is payable unless and until declared by the Board of Directors.

During 2005, the Utility paid cash dividends to holders of its various series of preferred stock outstanding totaling $21 million. Of this amount, approximately $16 million was paid on preferred stock without mandatory redemption provisions and approximately $5 million was paid on preferred stock with mandatory redemption provisions and accounted for as interest expense. In addition, the Utility paid cash dividends of $476 million on the Utility's common stock. Approximately $445 million in common stock dividends were paid to PG&E Corporation and the remainder were paid to PG&E Holdings LLC, a wholly owned subsidiary of the Utility that held approximately 7% of the Utility's common stock as of February 16, 2006.

On April 15, July 15 and October 17, 2005, PG&E Corporation paid a quarterly common stock dividend of $0.30 per share, totaling approximately $356 million. Of the total dividend payments made by PG&E Corporation in 2005, approximately $22 million was paid to Elm Power Corporation, a wholly owned subsidiary of PG&E Corporation. In addition, during 2005, PG&E Corporation paid approximately $17 million in dividend equivalent payments with respect to its Convertible Subordinated Notes.

On October 19, 2005, the PG&E Corporation Board of Directors approved an annual cash dividend target of $1.32 per share ($0.33 quarterly), an increase from the previously approved target of $1.20 per share that reflects the improved financial performance of PG&E Corporation, but balances the forecast level of Utility capital investments. Consistent with the new target, on December 21, 2005, the Board of Directors declared a dividend of $0.33 per share, totaling approximately $122 million, that was payable to shareholders of record on December 30, 2005 on January 16, 2006.

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

As discussed below in "Regulatory Matters," the CPUC may propose new rules to ensure that the California utilities retain sufficient capital to meet customers' needs and to address potential conflicts of interest between customers' interests and the interests of the parent holding companies and affiliates. PG&E Corporation and the Utility cannot predict whether any rules the CPUC may adopt will have a material impact on their ability to pay dividends in the future.

STOCK REPURCHASES

On December 15, 2004, PG&E Corporation entered into an accelerated share repurchase agreement, or ASR, with Goldman Sachs & Co., Inc., or GS&Co., under which PG&E Corporation repurchased 9,769,600 shares of its outstanding common stock for an aggregate purchase price of approximately $332 million, including a $14 million price adjustment paid on February 22, 2005. This adjustment was based on the daily volume weighted average market price, or VWAP, of PG&E Corporation common stock over the term of the arrangement.

In 2005, PG&E Corporation repurchased a total of 61,139,700 shares of its common stock through two ASRs with GS&Co. for an aggregate purchase price of $2.2 billion, including certain additional amounts such as a price adjustment based on the VWAP. Under the last of these ASRs, which was executed in November 2005, certain payments may still be required by both PG&E Corporation and GS&Co. Most significantly, PG&E Corporation may receive from, or be required to pay, GS&Co., as in previous ASRs, a price adjustment based on the VWAP over a period of approximately seven months. Over the remaining term of the ASR, for every $1 that the VWAP exceeds the initial per

share price of $34.75, PG&E Corporation will owe GS&Co. an additional $24.8 million. Conversely, for every $1 that the VWAP is below $34.75, the amount due from GS&Co. will be reduced by $24.8 million. See Note 8 of the Notes to the Consolidated Financial Statements for additional information on the November 2005 ASR.

PG&E Corporation's obligations under the ASR can be satisfied, at PG&E Corporation's option, in cash, in shares of PG&E Corporation's common stock, or a combination of the two. Until the ASR is completed or terminated, accounting principles generally accepted in the United States of America, or GAAP, requires PG&E Corporation to assume that it will issue shares to settle its obligations (up to a maximum of two times the number of shares repurchased or 63,300,600 shares). PG&E Corporation must calculate the number of shares that would be required to satisfy its obligations upon completion of the ASR based on the market price of PG&E Corporation's common stock at the end of a reporting period. The number of shares that would be required to satisfy the obligations must be treated as outstanding for purposes of calculating diluted earnings per share. Based on the market price of PG&E Corporation stock at December 31, 2005, PG&E Corporation would have an obligation to GS&Co. of approximately $71 million upon completion of the ASR. Accordingly, approximately 2 million additional shares of PG&E Corporation common stock attributable to the ASR were treated as outstanding for purposes of calculating diluted earnings per share.

PG&E Corporation's repurchase of common stock under these ASRs increased both basic and diluted EPS by approximately $0.16 and $0.15, respectively, for the year ended December 31, 2005.

Of the original $1.6 billion of stock repurchases authorized by the Board of Directors on October 19, 2005 to be made no later than December 31, 2006, $500 million of stock repurchase authorization remains. PG&E Corporation anticipates using between $100 million to $200 million during 2006 to repurchase shares in excess of shares repurchased to offset option exercises, using cash distributions received from the Utility. In addition, it is expected that shares will be repurchased with cash received through the exercise of stock options and that this would partially offset the number of shares issued pursuant to the exercise of those options, resulting in a minimal impact to the number of shares outstanding and the calculation of EPS.

The ultimate amount of stock repurchased by PG&E Corporation in 2006 will be affected by, among other factors, the changes to PG&E Corporation's and the Utility's liquidity needs, actual cash from the Utility's operations, the level of employee stock option exercises, and the actual level of the Utility's capital expenditures.

UTILITY

Operating Activities

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

The Utility's cash flows from operating activities for 2005, 2004 and 2003 were as follows:

(in millions)	2005	2004	2003
Net income	$ 934	$ 3,982	$ 923
Non-cash (income) expenses:			
Depreciation, amortization and decommissioning	1,697	1,494	1,218
Gain on establishment of regulatory asset, net	—	(2,904)	—
Change in accounts receivable	(245)	(85)	(590)
Change in accrued taxes	(150)	52	48
Other uses of cash:			
Payments authorized by the bankruptcy court on amounts classified as liabilities subject to compromise	—	(1,022)	(87)
Other changes in operating assets and liabilities	130	321	711
Net cash provided by operating activities	$2,366	$ 1,838	$2,223

In 2005, net cash provided by operating activities increased by approximately $528 million compared to 2004. This is mainly due to the following factors:

- The Utility received approximately $160 million related to settlements with El Paso Natural Gas Company and Mirant. See Note 17 of the Notes to the Consolidated Financial Statements for further discussion;
- In 2005, the Utility had approximately $100 million in additional expenditures related to gas procurement, administrative and general costs that were unpaid at the end of 2005. In 2004, the Utility did not have similar unpaid expenditures;

- In 2004, the Utility paid approximately $1 billion of allowed creditor claims with no similar amount in 2005;
- Collections on balancing accounts increased approximately $800 million in 2005 as compared to 2004 due to an increase in revenue requirements intended to recover 2004 undercollections;
- The Utility paid approximately $60 million more in 2005 as compared to 2004 for gas inventory as a result of increased gas prices; and
- In 2005, the Utility paid approximately $1.4 billion in tax payments as compared to approximately $100 million in 2004. This increase was primarily due to an increase in taxable generator settlements in 2005 as compared to 2004, and a decrease in deductible tax depreciation in 2005 as compared to 2004.

In 2004, net cash provided by operating activities decreased by approximately $385 million compared to 2003. This is mainly due to the following factors:

- Net income increased by approximately $431 million, excluding the one-time non-cash gain, after-tax, of approximately $2.9 billion related to the recognition of the regulatory assets established under the Settlement Agreement and including $276 million for the impact of depreciation, amortization, and decommissioning which are also non-cash items;
- Accounts receivable increased by approximately $505 million in 2004, as compared to 2003 when the Utility recorded a reduction to accounts receivable to reflect the settlement of an amount payable to the DWR. Amounts payable to the DWR are offset against amounts receivable from the Utility's customers for energy supplied by the DWR reflecting the Utility's role as a billing and collection agent for the DWR's sales to the Utility's customers;
- Payments authorized by the bankruptcy court on amounts classified as liabilities subject to compromise increased by approximately $935 million due to payment of all allowed creditor claims on the effective date; and
- Cash provided by operating assets and liabilities decreased by approximately $390 million primarily due to balancing account activity.

In November 2005, the CPUC approved an initiative to help consumers manage high natural gas bills in the winter. The 10/20 Winter Gas Savings Program is a conservation incentive that offers residential and small business customers a 20 percent rebate for reducing their gas usage by 10 percent or more this winter, January through March 2006. The Utility forecasts that this initiative will result in approximately $150 million in rebates to customers. As a result, the Utility's cash inflows will be lower during the first four months of 2006. However, the Utility expects to recover this cash through rates during April through October 2006.

Investing Activities

The Utility's investing activities consist of construction of new and replacement facilities necessary to deliver safe and reliable electricity and natural gas services to its customers. Cash flows from operating activities have been sufficient to fund the Utility's capital expenditure requirements during 2005, 2004 and 2003. Year to year variances in cash used in investing activities depend primarily upon the amount and type of construction activities, which can be influenced by storm and other damage.

The Utility's cash flows from investing activities for 2005, 2004 and 2003 were as follows:

(in millions)	2005	2004	2003
Capital expenditures	$(1,803)	$(1,559)	$(1,698)
Net proceeds from sale of assets	39	35	49
(Increase) decrease in restricted cash	434	(1,577)	(253)
Other investing activities, net	(29)	(178)	(114)
Net cash used by investing activities	$(1,359)	$(3,279)	$(2,016)

In 2005, net cash used by investing activities decreased by approximately $1.9 billion as compared to 2004. In 2004, net cash used by investing activities increased by approximately $1.3 billion as compared to 2003. These fluctuations are primarily due to changes in restricted cash. In 2004, the Utility deposited funds into an escrow account to pay disputed Chapter 11 claims when resolved.

Financing Activities

During its Chapter 11 proceeding, the Utility's financing activities were limited to repayment of secured debt obligations as authorized by the bankruptcy court. During this period, the Utility did not have access to the capital markets. In March 2004, in anticipation of its emergence from

Chapter 11, the Utility issued significant amounts of debt in order to finance its payments to be made in connection with the implementation of the plan of reorganization. The Utility also established a working capital facility and an accounts receivable financing facility for the purposes of funding its operating expenses and seasonal fluctuations in working capital and providing letters of credit.

In 2005, the Utility obtained $2.7 billion of proceeds from the ERBs. The proceeds were used to repay debt and repurchase equity.

The Utility's cash flows from financing activities for 2005, 2004 and 2003 were as follows:

(in millions)	2005	2004	2003
Net proceeds from long-term debt issued	$ 451	$7,742	$ –
Net proceeds from energy recovery bonds issued	2,711	–	–
Net borrowings under accounts receivable facility and working capital facility	260	300	–
Net repayments under working capital facility	(300)	–	–
Rate reduction bonds matured	(290)	(290)	(290)
Energy recovery bonds matured	(140)	–	–
Long-term debt, matured, redeemed or repurchased	(1,554)	(8,402)	(281)
Common stock dividends paid	(445)	–	–
Preferred dividends paid	(16)	(90)	–
Preferred stock with mandatory redemption provisions redeemed	(122)	(15)	–
Preferred stock without mandatory redemption provisions redeemed	(37)	–	–
Common stock repurchased	(1,910)	–	–
Other financing activities	65	–	–
Net cash used by financing activities	$(1,327)	$(755)	$(571)

In 2005, net cash used by financing activities increased by approximately $572 million compared to 2004. This is mainly due to the following factors:

- During 2005, proceeds from long-term debt decreased by approximately $7.3 billion. In 2004, in connection with the Utility's plan of reorganization, the Utility issued approximately $7.7 billion, net of issuance costs of $107 million, in long-term debt. In 2005, the only long-term debt incurred by the Utility was seven loan agreements with the California Infrastructure and Economic Development Bank to issue PC Bonds Series A-G, totaling $451 million, net of issuance costs of $3 million;
- PERF issued two separate series of ERBs in 2005 in the aggregate amount of $2.7 billion with no similar issuance in 2004 (see Note 6 of the Notes to the Consolidated Financial Statements for further discussion). In March 2005, the Utility used some of the proceeds from the issuance of the first series of ERBs to repurchase $960 million of its common stock from PG&E Corporation. In November 2005, the Utility used the proceeds from the issuance of the second series of ERBs to repurchase $950 million of its common stock from PG&E Corporation;
- Net borrowings under the accounts receivable facility and working capital facility were $260 million in 2005 due to the Utility borrowing $260 million under its accounts receivable facility in the fourth quarter;
- Net repayments under the working capital facility were $300 million in 2005 due to the Utility repaying in the first quarter $300 million it borrowed under its working capital facility;
- Approximately $140 million of ERBs matured in 2005 with no similar maturities in 2004;
- During 2005, long-term debt matured, redeemed, or repurchased by the Utility decreased by approximately $6.8 billion. In 2005, the Utility redeemed $1.1 billion of floating rate debt and repaid $454 million under certain reimbursement obligations the Utility entered into in April 2004 when its plan of reorganization under Chapter 11 became effective. In 2004, repayments on long-term debt totaled approximately $8.4 billion, primarily to discharge pre-petition debt at the effective date of the plan of reorganization;
- In 2005, the Utility paid $445 million in common stock dividends to PG&E Corporation and $31 million to PG&E Holdings LLC, a wholly owned subsidiary of the Utility;
- In 2005, the Utility redeemed $122 million of preferred stock with mandatory redemption provisions compared to $15 million in 2004;
- In 2005, the Utility redeemed $37 million of preferred stock without mandatory redemption provisions with no similar redemption in 2004; and
- In 2005, approximately $100 million was received from customers for deposits to ensure that they do not exceed the credit risk threshold that has been set for them, with no similar amount in 2004.

In 2004, net cash used by financing activities increased by approximately $184 million as compared to 2003. This was mainly due to the following factors:

- In March 2004, the Utility consummated a public offering of $6.7 billion in First Mortgage Bonds. In April 2004, the Utility entered into pollution control bond loans in the amount of $454 million and borrowed $350 million under the accounts receivable financing facility. In June 2004, the Utility entered into four separate loan agreements with the California Pollution Control Financing Authority, which issued $345 million aggregate principal amount of its Pollution Control Refunding Revenue Bonds;
- Partially offsetting these proceeds are issuance costs of approximately $107 million associated with the $6.7 billion in First Mortgage Bonds, working capital facilities, bridge loans and other exit financing activities;
- In November 2004, the Utility borrowed $300 million under its working capital facility;
- The amount of long-term debt, matured, redeemed or repurchased in 2004 was approximately $8.4 billion compared to $281 million in 2003. In 2004, the Utility paid $310 million in March 2004 upon maturity of secured debt, $6.9 billion of long-term debt on the effective date of its plan of reorganization and $345 million of pollution control bond loans in June 2004. In 2003, the Utility repaid approximately $281 million in principal on its mortgage bonds that matured in August 2003;
- In May 2004, the Utility repaid $350 million borrowed under the accounts receivable financing facility;
- In October 2004, the Utility redeemed $500 million of Floating Rate First Mortgage Bonds;
- The Utility paid approximately $90 million of preferred stock dividends during 2004; and
- The Utility redeemed approximately $15 million of preferred stock with mandatory redemption provisions during 2004.

PG&E CORPORATION

As of December 31, 2005, PG&E Corporation had stand-alone cash and cash equivalents of approximately $250 million. PG&E Corporation's sources of funds are dividends and share repurchases from the Utility, issuance of its common stock and external financing. In 2005 the Utility paid a total cash dividend of $445 million to PG&E Corporation and PG&E Holdings LLC and repurchased $1.9 billion of its common stock from PG&E Corporation. The Utility did not pay any dividends to, nor repurchase shares from, PG&E Corporation during 2004 or 2003.

Operating Activities

PG&E Corporation's consolidated cash flows from operating activities consist mainly of billings to the Utility for services rendered and payments for employee compensation and goods and services provided by others to PG&E Corporation. PG&E Corporation also incurs interest costs associated with its debt.

PG&E Corporation's consolidated cash flows from operating activities for 2005, 2004 and 2003 were as follows:

(in millions)	2005	2004	2003
Net income	$ 917	$ 4,504	$ 420
Gain on disposal of NEGT (net of income tax benefit of $13 million in 2005 and income tax expense of $374 million in 2004)	(13)	(684)	–
Loss from operations of NEGT (net of income tax benefit of $230 million)	–	–	365
Cumulative effect of changes in accounting principles	–	–	6
Net income from continuing operations	904	3,820	791
Non-cash (income) expenses:			
Depreciation, amortization and decommissioning	1,698	1,497	1,222
Deferred income taxes and tax credits, net	(659)	611	190
Recognition of regulatory asset, net of tax	–	(2,904)	–
Other deferred charges and noncurrent liabilities	33	(519)	857
Loss from retirement of long-term debt	–	65	89
Gain of sale of assets	–	(19)	(29)
Tax benefit from employee stock plans	50	41	–
Other changes in operating assets and liabilities	383	(736)	(381)
Net cash provided by operating activities	$2,409	$ 1,856	$2,739

In 2005, the net cash provided by operating activities increased by $553 million compared to 2004 primarily due to an increase in the Utility's net cash provided by operating activities.

In 2004, the net cash provided by operating activities decreased by approximately $883 million compared to 2003 as a result of NEGT's realized losses generated through July 7, 2003, and 2004 payments totaling approximately $85 million for PG&E Corporation's senior executive retention program and $30 million pursuant to a settlement of certain tax-related litigation between PG&E Corporation and NEGT. There were no similar payments in 2003.

Investing Activities

On March 8, 2005, PG&E Corporation received $960 million in proceeds for the repurchase of 22,023,283 shares of Utility common stock by the Utility. In addition, on November 21, 2005, PG&E Corporation received $950 million in proceeds for the repurchase of 19,666,654 shares of Utility common stock by the Utility. These transactions were eliminated in consolidation.

PG&E Corporation, on a stand-alone basis, did not have any material investing activities in the years ended December 31, 2005, 2004 and 2003.

Financing Activities

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

PG&E Corporation's cash flows from financing activities for 2005, 2004 and 2003 were as follows:

(in millions)	2005	2004	2003
Net borrowings under accounts receivable facility and working capital facility	$ 260	$ 300	$ –
Net repayments under working capital facility	(300)	–	–
Net proceeds from issuance of energy recovery bonds	2,711	–	–
Net proceeds from long-term debt issued	451	7,742	581
Long-term debt matured, redeemed or repurchased	(1,556)	(9,054)	(1,068)
Rate reduction bonds matured	(290)	(290)	(290)
Energy recovery bonds matured	(140)	–	–
Preferred stock with mandatory redemption provisions redeemed	(122)	(15)	–
Preferred stock without mandatory redemption provisions redeemed	(37)	–	–
Common stock dividends paid	(334)	–	–
Common stock issued	243	162	166
Common stock repurchased	(2,188)	(378)	–
Preferred dividends paid	(16)	(90)	–
Other, net	48	(1)	(4)
Net cash used by financing activities	$(1,270)	$(1,624)	$ (615)

In 2005, PG&E Corporation's consolidated net cash used by financing activities decreased by approximately $354 million, compared to 2004. The decrease is primarily due to the PERF issuance of two separate series of ERBs in 2005 in the aggregate amount of $2.7 billion with no similar issuance in 2004. During 2005, PG&E Corporation repurchased a total of 61,139,700 shares of its common stock through two accelerated share repurchase arrangements for an aggregate purchase price of $2.2 billion.

In 2004, PG&E Corporation's consolidated net cash used by financing activities increased by approximately $1 billion, compared to 2003. The increase is primarily due to the November 15, 2004 redemption of the Senior Secured Notes for approximately $664.5 million including a redemption premium of approximately $50.7 million and $13.8 million of accrued interest. During 2004, PG&E Corporation repurchased 11,633,200 shares of PG&E Corporation common stock (of which 850,000 shares were purchased by Elm Power Corporation, PG&E Corporation's subsidiary) at a cost of approximately $378 million (including $28 million paid by Elm Power Corporation).

CONTRACTUAL COMMITMENTS

The following table provides information about the Utility's and PG&E Corporation's contractual obligations and commitments at December 31, 2005. PG&E Corporation and the Utility enter into contractual obligations in connection with business activities. These obligations primarily relate to financing arrangements (such as long-term debt, preferred stock and certain forms of regulatory financing), purchases of transportation capacity, natural gas and electricity to support customer demand and the purchase of fuel and transportation to support the Utility's generation activities.

	Payment due by period				
(in millions)	Total	Less than one year	1–3 years	3–5 years	More than 5 years
Contractual Commitments:					
Utility					
Purchase obligations:					
Power purchase agreements[1]:					
Qualifying facilities	$20,694	$2,041	$4,549	$3,371	$10,733
Irrigation district and water agencies	573	79	137	111	246
Other power purchase agreements	1,011	118	200	103	590
Natural gas supply and transportation[2]	1,614	1,447	154	13	–
Nuclear fuel	295	104	113	65	13
Preferred dividends and redemption requirements[3]	42	8	17	17	–
Employee benefits:					
Pension[4]	20	20	–	–	–
Postretirement benefits other than pension[4]	65	65	–	–	–
Other commitments[5]	121	111	10	–	–
Advanced Metering Infrastructure	14	14	–	–	–
Operating leases[6]	105	35	46	12	12
Long-term debt[7]:					
Fixed rate obligations	11,742	295	934	1,156	9,357
Variable rate obligations	1,802	36	69	686	1,011
Other long-term liabilities reflected on the Utility's balance sheet under GAAP:					
Rate reduction bonds[8]	623	321	302	–	–
Energy recovery bonds[9]	3,044	431	871	871	871
Capital lease	8	2	4	2	–
PG&E Corporation					
Long-term debt[7]:					
Convertible subordinated notes	399	27	53	319	–
Operating leases	16	3	6	4	3
Accelerated share repurchase (ASR)[10]	71	71	–	–	–

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

(2) See Note 17 of the Notes to the Consolidated Financial Statements for further discussion of assigned natural gas capacity contracts.

(3) Preferred dividend and redemption requirement estimates beyond 5 years do not include non-redeemable preferred stock dividend payments as these continue in perpetuity.

(4) PG&E Corporation's and the Utility's funding policy is to contribute tax deductible amounts, consistent with applicable regulatory decisions, sufficient to meet minimum funding requirements. Contribution estimates after 2007 will be driven by CPUC decisions. See further discussion under "Regulatory Matters."

(5) Includes commitments for capital infusion agreements for limited partnership interests in the aggregate amount of approximately $7 million, contracts to retrofit generation equipment at the Utility's facilities in the aggregate amount of approximately $11 million, load-control and self-generation CPUC initiatives in the aggregate amount of approximately $73 million, contracts for local and long-distance telecommunications in the aggregate amount of approximately $4 million and contracts related to energy efficiency programs in the aggregate amount of approximately $26 million.

(6) Includes a power purchase agreement accounted for as an operating lease.

(7) Includes interest payments over terms of debt. See Note 4 of the Notes to the Consolidated Financial Statements for further discussion.

(8) Includes interest payments over the terms of the bonds. See Note 5 of the Notes to the Consolidated Financial Statements for further discussion of rate reduction bonds.

(9) Includes interest payments over the terms of the bonds. See Note 6 of the Notes to the Consolidated Financial Statements for further discussion of ERBs.

(10) See Note 8 of the Notes to the Consolidated Financial Statements for further discussion of the ASR.

UTILITY

The Utility's contractual commitments include power purchase agreements (including agreements with QFs, irrigation districts and water agencies and renewable energy providers), natural gas supply and transportation agreements, nuclear fuel agreements, operating leases and other commitments that are discussed in Note 17 of the Notes to the Consolidated Financial Statements.

CAPITAL EXPENDITURES

The Utility's investment in plant and equipment totaled approximately $1.9 billion in 2005, $1.6 billion in 2004 and $1.7 billion in 2003. The Utility's annual capital expenditures are expected to increase to an average of approximately $2.5 billion annually over the next five years. These expenditures are necessary to replace aging infrastructure and accommodate anticipated electricity and natural gas load growth of approximately 1.3% and 1.0% per year, respectively. Capital expenditures for which contracts or firm commitments exist have, in addition to being included in estimated capital expenditures, been included in the "Contractual Commitments" table above, which details the Utility's contractual obligations and commitments at December 31, 2005. The estimate of capital expenditures over the next five years includes the following significant capital expenditure projects:

- New customer connections, replacements, upgrades and expansion of the existing electricity distribution systems (including expenditures for the Advanced Metering Infrastructure, or AMI, program) expected to average approximately $1.0 billion annually over the next five years;
- Replacement of natural gas distribution pipelines expected to average approximately $310 million annually over the next five years;
- Replacements, capacity expansion, and other life extension programs of the electricity transmission system expected to average approximately $360 million annually over the next five years;
- Replacements and upgrades for improved system reliability to the Utility's natural gas transportation facilities expected to average approximately $150 million annually over the next five years;
- Replacements and upgrades of existing facilities at Diablo Canyon, including replacement of the turbines and steam generators, potential investments in a new combined cycle generation unit in Contra Costa County that may be acquired pursuant to a settlement agreement with the Mirant Corporation (Contra Costa 8); replacements, upgrades and relicensing of the Utility's hydroelectric generation facilities; and the repowering of the Humboldt Bay Power Plant. All of these generation-related projects are expected to average approximately $440 million annually over the next five years; and
- Investment in common plant, including computers, vehicles, facilities and communications equipment, expected to average approximately $260 million annually over the next five years.

The Utility retains the ability to delay or defer substantial amounts of these planned expenditures in light of changing economic conditions and changing technology. It is also possible that these projects may be replaced by other projects. In addition, the Utility would not incur these capital expenditures without CPUC authorization. Consistent with past practice, the Utility expects that any capital expenditures will be included in its rate base and recoverable in rates. Based on the estimate of average capital expenditures of approximately $2.5 billion annually over the next five years, the Utility's average annual rate base is expected to grow by approximately 6% per year over the five-year period.

At December 31, 2005, the Utility is committed to spending approximately $346 million for the conversion of existing overhead electric facilities to underground electric facilities. Although the majority of these costs are expected to be spent over the next five years, the timing of the work is dependent upon a number of factors, including the schedules of the respective cities and counties and telephone utilities involved. The Utility expects to spend approximately $50 to $55 million each year in connection with these projects for the next five years. These annual estimates are included in the approximately $2.5 billion estimated annual expenditures above.

The Utility's capital expenditures to comply with environmental laws and regulations were $6.9 million in 2005, $4.2 million in 2004 and $3.6 million in 2003. The capital expenditure forecast includes the estimated cost to comply with these regulations of approximately $68.5 million.

Advanced Metering Infrastructure

The CPUC is assessing the viability of implementing an AMI for residential and small commercial customers. This infrastructure would enable California investor-owned electric utilities to measure usage of electricity on a time-of-use basis and to charge demand-responsive rates. The goal of demand-responsive rates is to encourage customers to reduce energy consumption during peak demand periods and to reduce peak period procurement costs. Advanced meters can record usage in time intervals and be read remotely. The Utility is implementing demand responsive tariffs for large industrial customers, who already have advanced metering systems in place, and a statewide pilot program was recently completed to test whether and how much residential and small commercial customers will respond to demand-responsive rates.

The Utility requested that the CPUC authorize the Utility to incur costs to engage in certain pre-deployment activities to implement AMI, such as preparing the Utility's existing systems to accept data from its proposed advanced metering system, and establishing and testing processes for meter and communication system installation and billing. In September 2005, the CPUC approved the Utility's application and authorized the Utility to recover up to $49 million (including $37.4 million in capital additions) on pre-deployment activities from customers, resulting in electric and gas distribution revenue requirements of approximately $13.8 million in 2005, $6.3 million in 2006 and $6.2 million in 2007. The Utility Reform Network, or TURN, has filed an application for rehearing of the CPUC's decision.

The Utility anticipates that the CPUC will issue a decision on the Utility's application for approval of full deployment of its AMI project in 2006. The Utility estimates that full deployment of AMI would cost approximately $1.6 billion, including an estimated capital cost of $1.4 billion, based on a five-year installation schedule for virtually all of the Utility's electric and gas customers starting in 2006.

The Utility has entered into several vendor contracts related to AMI deployment which provide for aggregate payments of up to approximately $900 million over the five-year deployment installation schedule. Each of these AMI contracts contains termination clauses that allow the Utility to terminate the contracts at the Utility's convenience for any reason. Three of the five contracts contain cancellation penalties which are capped at approximately $14 million before deployment and could exceed that amount post-deployment. The Utility would seek to recover the amount of any penalties it may be required to pay upon cancellation through rates.

The Utility expects that approximately 89% of the AMI project costs would be offset by the anticipated operational savings and efficiencies resulting from AMI. The remaining 11% is expected to be offset by electric procurement savings resulting from voluntary customer participation in demand response options.

PG&E Corporation and the Utility cannot predict whether the CPUC will approve the Utility's application for approval of full deployment of its AMI project or whether the anticipated benefits and costs savings would be realized.

Diablo Canyon Steam Generator Replacement Project

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

On August 15, 2005, the final environmental impact report, or EIR, required by the California Environmental Quality Act was issued with respect to the Utility's proposal for the SGRP. The final EIR found that, for the SGRP as a whole, there are no environmental impacts that are significant, provided certain mitigation measures are implemented.

On November 18, 2005, the CPUC issued a decision that certified the EIR as final and approved the Utility's SGRP. The decision concluded that the SGRP is cost-effective, that $706 million, as adjusted for actual inflation and cost of capital, is a reasonable estimate of the SGRP cost, and that the Utility cannot recover costs in excess of $815 million, as adjusted for actual inflation and cost of capital. The decision also states that (1) if the costs do not exceed $706 million, the CPUC does not intend to conduct an after-the-fact reasonableness review of the SGRP costs, but that such a review was not precluded, and (2) if the SGRP cost exceeds $706 million, as adjusted for actual inflation and cost of capital, or the CPUC later finds that it has reason to believe the costs may be unreasonable regardless of the amount, the entire SGRP cost will be subject to a reasonableness review.

As of December 31, 2005, the Utility had incurred approximately $78 million in connection with the SGRP under various construction and installation contracts the Utility has executed. Based on updated estimates of the cost to complete the SGRP, the Utility estimates it will spend up to an additional $550 million to complete the SGRP through 2009.

To implement the SGRP, the Utility requires two permits from San Luis Obispo County; a conditional use permit to store the old generators on site at Diablo Canyon and a coastal development permit to build temporary structures at Diablo Canyon to house the new generators as they are prepared for installation. At a public hearing on January 12, 2006, the San Luis Obispo County Planning Commission denied approval of both permits. The Utility will appeal these denials to the Board of Supervisors of San Luis Obispo County, who will hold a public hearing to consider the appeals in early March 2006. The Utility anticipates that any decision by the Board of Supervisors on the coastal development permit would be appealed to the California Coastal Commission and that the Utility would participate in the appeals process and proactively engage the Coastal Commission in order to obtain the coastal development permit. The Utility is targeting to receive both permits by the end of 2006; but if the Utility is unable to obtain a conditional use permit, implementation would be delayed as the Utility explores off-site storage solutions for the old generators.

OFF-BALANCE SHEET ARRANGEMENTS

For financing and other business purposes, PG&E Corporation and the Utility utilize certain arrangements that are not reflected in their Consolidated Balance Sheets. Such arrangements do not represent a significant part of either PG&E Corporation's or the Utility's activities or a significant ongoing source of financing. These arrangements are used to enable PG&E Corporation or the Utility to obtain financing or execute commercial transactions on favorable terms. For further information related to letter of credit agreements, the credit facilities, aspects of PG&E Corporation's accelerated share repurchase program and PG&E Corporation's guarantee related to certain NEGT indemnity obligations, see Notes 4, 8 and 17 of the Notes to the Consolidated Financial Statements. Amounts due under these contracts are contingent upon terms contained in these agreements.

CONTINGENCIES

PG&E Corporation and the Utility have significant contingencies that are discussed below. Also, refer to Note 17 in the Notes to the Consolidated Financial Statements for further discussion.

REGULATORY MATTERS

This section of MD&A discusses significant regulatory issues pending before the CPUC, the FERC, and the Nuclear Regulatory Commission, or NRC, the resolution of which may affect the Utility's and PG&E Corporation's results of operations or financial condition.

2007 General Rate Case

On December 2, 2005, the Utility filed its 2007 GRC application with the CPUC for the 2007–2009 period based on a forecast of costs for the 2007 test year.

In its application, the Utility has requested:

- An increase in electric and gas distribution revenue requirements of $481 million and $114 million, respectively, over the authorized 2006 revenue requirements to maintain current service levels to support increased investment in distribution infrastructure as plant in service is upgraded and replaced, and to adjust for wages and inflation;
- An increase of $87 million, over the authorized 2006 revenue requirement, to cover increases in operational costs for the Utility's fossil, hydro, and nuclear generation facilities and administrative costs associated with electric procurement activities; and
- Attrition increases of $186 million for 2008 and $243 million for 2009 designed to avoid a reduction in earnings in years between GRCs that would otherwise occur because of increases in rate base and expenses.

The authorized 2006 revenue requirements referred to above consist of the 2005 authorized revenue requirements plus authorized attrition revenue increases of $132 million for electric and gas distribution, and $35 million for electric generation. The 2006 authorized revenue requirement was included in the Utility's AET filing supplement filed with the CPUC in December 2005 and has been reflected in rates beginning January 1, 2006.

The 2007 GRC application includes a request for approval of pension contributions of $345 million per year in 2007, 2008 and 2009, and seeks an annual revenue requirement of $216 million to fund the portion of each year's pension contribution attributable to the Utility's distribution and generation businesses. The Utility included this request because the CPUC had not yet issued a final decision on the Utility's July 2005 petition for permission to file a separate application to resume pension contributions beginning in 2006. In December 2005, the CPUC approved, in part, the July 2005 petition, giving the Utility permission to file an application for a pension contribution in 2006 and to begin collecting the requested revenue requirement through rates effective January 1, 2006, subject to refund. The Utility filed the pension contribution application in December 2005, requesting approval of a pension contribution of $250 million in 2006 and seeking a 2006 revenue requirement of $155 million to fund the portion of the contribution attributable to the Utility's distribution and generation businesses. The application promises to supplement the pension request in the 2007 GRC to make clear that if the pension application is approved in full, the annual pension requirement in the years 2007 through 2009 will be reduced from the originally requested $216 million to the level for 2007 associated with an annual net pension contribution of $250 million on a total company basis. (See the "Defined Benefit Pension Plan Contributions" section of "Regulatory Matters" for further information regarding the 2006 pension contribution application).

In the 2007 GRC application, the Utility also has proposed to reduce the 2008 and 2009 total gas and electric revenue requirements that it has otherwise requested (including attrition increases of $186 million for 2008 and $243 million for 2009) by $41 million in 2008 and $97 million in 2009 to capture an estimate of net savings that the Utility anticipates may be realized from the operating and cost efficiencies achieved through implementation of specific initiatives identified by the Utility to provide better, faster and more cost-effective service to its customers. Due to

uncertainty about savings to be realized from these initiatives, the Utility has proposed a sharing mechanism in its GRC application by which shareholders and customers would share equally in any earnings over the amount needed to achieve a ROE, on GRC rate base equal to the then-authorized ROE plus 50 basis points. The Utility's customers would receive 100% of the earnings over the amount needed to achieve an ROE equal to the then-authorized ROE plus 300 basis points. If the Utility's actual ROE were less than an amount equal to the then-authorized ROE minus 50 basis points, shareholders and customers would share the shortfall equally.

The following table summarizes the proposed sharing mechanism based on the Utility's 2005 authorized ROE of 11.22%:

ROE	Customer	Shareholder
Below 10.72%	50%	50%
10.72% – 11.72%	0%	100%
11.73% – 14.22%	50%	50%
Above 14.22%	100%	0%

As discussed in the "2006 Cost of Capital Proceeding" section, the Utility's 2006 authorized ROE is 11.35%. The following table summarizes the proposed sharing mechanism based on the Utility's 2006 authorized ROE:

ROE	Customer	Shareholder
Below 10.85%	50%	50%
10.85% – 11.85%	0%	100%
11.86% – 14.35%	50%	50%
Above 14.35%	100%	0%

In addition, the Utility's 2007 GRC application includes a proposal to replace the current incentive mechanism for reliability performance for the 2007–2009 period with a new customer service performance incentive mechanism. Under the proposal, the Utility would be rewarded or penalized up to $60 million per year (increased from the current maximum of $24 million per year) to the extent that the Utility's actual performance exceeds or falls short of pre-set annual performance improvement targets over the 2007–2009 period. The Utility has proposed to expand the areas of performance to be measured to include the following: generation availability (the amount of generating capacity capable of generating power over time, with reduction due to both planned and unplanned outages), timeliness of bills, telephone service level, average outage time over a one-year period (known as the system average interruption duration index), average number of sustained outages over a one-year period (known as the system average interruption frequency index), and how accurately the Utility provides outage information and estimates of power restoration.

On February 3, 2006, a CPUC commissioner issued a ruling and scoping memo adopting a 2007 GRC schedule which provides for a final decision on all issues except the proposed customer service performance incentive mechanism by December 14, 2006. The performance incentive mechanism will be addressed in a separate phase, with a decision expected in April 2007. The schedule includes two mandatory settlement conferences, to be held on March 30 and May 10, 2006.

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

2006 Cost of Capital Proceeding

Under the Settlement Agreement, the Utility's authorized ROE shall be no less than 11.22% and the authorized equity ratio for ratemaking purposes shall be no less than 52% until the Utility's long-term issuer credit rating is at least A– from S&P or A3 from Moody's.

On December 15, 2005, the CPUC issued a decision approving a capital structure for the Utility consisting of 46% long-term debt, 2% preferred stock and 52% equity. The CPUC set the rate of return that the Utility may earn on its electricity and natural gas distribution and electricity generation rate base for 2006 at 6.02% for long-term debt, 5.87% for preferred stock and 11.35% for equity, resulting

in an overall rate of return on rate base of 8.79%. The Utility's rate of return for its electric transmission operations is set by the FERC and the Utility's rate of return for its gas transmission and storage operations through 2007 has been previously set in the Gas Accord settlement agreement approved by the CPUC.

The Utility's new authorized cost of capital is expected to increase 2006 revenue requirements by approximately $4 million over the previously authorized amounts.

Electricity Generation Resources

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

Procurement Cost Balancing Account and Mandatory Rate Adjustments

Effective January 1, 2003, as authorized by California law, the Utility established a balancing account, the Energy Resource Recovery Account, or ERRA, designed to track and allow recovery of the difference between the authorized revenue requirement and actual costs incurred under the Utility's authorized procurement plans, excluding the costs associated with the DWR allocated contracts and certain other items. The CPUC reviews the revenues and costs associated with an investor-owned utility's electricity procurement plan at least semi-annually. The CPUC has agreed to adjust retail electricity rates or order refunds, as appropriate, when the forecast aggregate over-collections or under-collections exceed 5% of the utility's prior year electricity procurement revenues, excluding amounts collected for the DWR. As of December 31, 2005, the ERRA had an overcollected balance of approximately $44 million, which is below the 5% trigger threshold for 2005 of $164.4 million.

In December 2005, the CPUC approved a 2006 ERRA revenue requirement for the Utility of $2.48 billion. The CPUC also approved the Utility's request to collect $340 million through the Utility's ongoing Competition Transition Charge revenue requirement. The Utility began collecting these revenue requirements in rates effective January 1, 2006 as part of the AET adjustments approved by the CPUC, subject to review, verification, and adjustment, if necessary, by the CPUC.

The CPUC performs periodic compliance reviews of the procurement activities recorded in the ERRA to ensure that the Utility's procurement activities are in compliance with its approved procurement plans. The cost of procurement activities could be disallowed up to a maximum of two times the Utility's annual procurement administrative expenditures (gas procurement activities, including hedging, and generation expenses, are excluded from this cap). For 2005, this amount is $36 million. It is uncertain whether the CPUC will modify or eliminate the maximum disallowance for future years.

In November 2005, the CPUC approved the Utility's administration of its power purchase agreements, procurement of least cost dispatch power, power activities, and associated procurement revenues and expenses for 2004.

In the first quarter of 2006, the Utility plans to file the ERRA Compliance Review Application for 2005. CPUC review is expected to be completed before the end of 2006.

New Long-Term Generation Resource Commitments

In December 2004, the CPUC issued a final decision which approved, with certain modifications, each investor-owned electric utility's long term procurement plan in order to authorize each utility to plan for and procure the resources necessary to provide reliable service to their customers for the ten-year period 2005–2014. The decision recognizes that each utility has capacity needs over the ten-year period. Specifically, the CPUC found that the Utility had a long-term need for up to 2,200 megawatts, or MW, of capacity through 2010.

In accordance with the Utility's CPUC-approved long-term electricity procurement plan, in March 2005 the Utility requested offers from providers of all potential sources of new generation (e.g., conventional or renewable resources to be provided by utility-owned projects or third-party power purchase agreements) for up to 2,200 MW of peaking and load-following resources, beginning in 2008. In addition, the Utility requested offers for new sources of generation to replace its existing 135 MW Humboldt Bay generating facility, which it expects to retire in 2009. Finally, the Utility requested offers from new and existing QFs.

The Utility selected participants to provide offers which were submitted in late October 2005. The Utility anticipates completing contract negotiations in the first quarter of 2006. The contracts that the Utility ultimately executes will depend on the outcome of these negotiations and an updated assessment of the Utility's future power needs. Further, as discussed under Note 17 of the Notes to the Consolidated Financial Statements, pursuant to the Utility's settlement with Mirant Corporation and certain of its subsidiaries, or Mirant, the Utility has requested that the CPUC approve an agreement with Mirant implementing one part of the settlement under which the Utility would acquire and complete the Contra Costa Unit 8 facility, a 530 MW electric generating facility. With respect to this request, the Utility has reached a settlement with key consumer groups, though this settlement has been contested by other parties to the proceeding. CPUC action is expected on this application by March or April, 2006. The Utility's assessment of its generation resource needs may be affected by whether the CPUC approves the Utility's application to acquire and complete the Contra Costa 8 facility.

In October 2005, the CPUC issued a decision that reaffirms and clarifies the policy framework the CPUC established in its December 2004 decision addressing resource adequacy. The October 2005 decision sets forth numerous rules in furtherance of that policy, including a penalty provision for failure to acquire sufficient capacity needed to meet resource adequacy requirements. The penalty is equal to three times the cost of the new capacity the deficient load-serving entity should have secured, but for 2006 the penalty is set at one-half of the amount. The Utility's CPUC-approved long-term procurement plan forecasts that the Utility will be able to meet the resource adequacy requirements. If the CPUC determines that the Utility has not met the requirements, the Utility could be subject to penalties in an amount determined by the CPUC in accordance with the new penalty provision.

To help assure recovery of the Utility's cost of new long-term resource commitments, the CPUC adopted a non-bypassable charge to be collected from all customers on whose behalf the Utility makes these new commitments, including those who subsequently receive generation from other load-serving entities.

In addition, in its decision approving the Utility's long-term procurement plans, the CPUC recognized that credit rating agencies will consider obligations under long-term procurement contracts to have debt-like characteristics that will adversely affect the Utility's credit ratios, which may, in turn, adversely affect the resulting credit ratings. The CPUC has agreed that it will consider the debt equivalence impact of procurement contracts on credit ratings in future cost of capital proceedings. The Utility is required to employ S&P's method for assessing the debt equivalence of power purchase agreements when evaluating bids in an all-source solicitation, except that the debt equivalence factor should be 20% instead of 30%. As the Utility enters into contracts with counterparties, the customers will be exposed to the risk that counterparties will fail to perform and associated business credit risks.

The CPUC also determined that for utility-owned generation resources, the utilities are prohibited from recovering construction costs in excess of their final bid price. If final construction costs are less than the final bid price, the savings would be shared with customers, while any cost overruns would be absorbed by the utilities. In September 2005, the CPUC granted limited rehearing of its determination that construction cost savings should be shared with customers, while any cost overruns would be absorbed by the utilities. In December 2005, the CPUC agreed to revisit its determination regarding the "cost cap" and the sharing of construction cost savings early in 2006.

The CPUC determined that costs of future plant additions and annual operating and maintenance costs for utility-owned generation and similar costs incurred by a utility would be eligible for cost-of-service ratemaking treatment. If the Utility is not able to recover a material part of the cost of developing or acquiring additional generation facilities in rates in a timely manner, PG&E Corporation's and the Utility's financial condition and results of operations would be materially adversely affected.

In January 2006, the FERC proposed regulations to implement Section 210(m) of the Public Utility Regulatory Policies Act of 1978, or PURPA, which was enacted as part of the Energy Policy Act of 2005. Section 210(m) authorizes the FERC to waive the obligation of an electric utility under Section 210 of PURPA both (1) to purchase the electricity offered to it by a QF (under a new contract or obligation) if certain conditions are met, and (2) to sell electricity to the QF if certain conditions are met. The statute would permit such waivers as to a particular QF or on a "service territory-wide basis." While the FERC's proposed regulations would grant blanket waivers from the obligation to purchase for certain areas under the control of a regional transmission organization, the FERC has concluded that the ISO market does not qualify for such status due to the lack of a functioning day-ahead market, i.e., a market in which electricity deliveries are scheduled a day before delivery. The ISO intends to implement a day-ahead market in late 2007. The proposed regulations would authorize utilities to make a showing on a case by case basis that short and long-term markets are sufficiently competitive to warrant waiver of the PURPA mandatory purchase obligation. The Utility intends to apply for a service territory-wide waiver of its QF purchase obligations under this case by case approach. The Utility is unable to predict whether the FERC will grant the Utility such a waiver.

Renewable Energy Contracts

California law requires that each California retail seller of electricity, except for municipal utilities, must increase its purchases of renewable energy (such as biomass, wind, solar and geothermal energy) by at least 1% of its retail sales per year, the annual procurement target, so that the amount of electricity purchased from renewable resources equals at least 20% of its total retail sales by the end of 2017. In January 2005, the California Senate introduced a bill proposing to require the goal to be met by 2010 instead of 2017. The CPUC also has recommended that the 20% goal be met by 2010 and may consider a 33% goal to be met by 2020. The Utility estimates that accelerating the 20% goal to 2010 would require the Utility to increase the amount of its annual renewable energy purchases to approximately 1.1% of retail sales. To meet the Renewable Portfolio Standards, or RPS goals, the Utility signed six new renewable power purchase contracts in 2005.

The CPUC is assessing the ability of the utilities to achieve the 20% target and ordered the utilities to file supplements to their 2005 RPS Plan filed in March 2005. The Utility stated that although it expects it will achieve the 20% target through signed contracts by 2010, actual deliveries of renewable power may not comprise 20% of its bundled retail sales by 2010 due to the time required for new project construction. Failure to satisfy the annual procurement targets may result in a CPUC imposed penalty of five cents per kilowatt hour or kWh with an annual penalty cap of $25 million and failure to meet the 20% renewable procurement obligation may result in additional penalties.

To meet the 20% target, the CPUC has ordered an investigation to proactively take steps to ensure the development of transmission infrastructure to access renewable resources for California. In 2006 the Utility will continue to plan for and begin implementation of transmission projects, which among other purposes can improve access to renewable energy projects.

DWR Allocated Contracts

The Utility acts as a billing and collection agent for the DWR's revenue requirements from the Utility's customers. The DWR's revenue requirements consist of a power charge to pay for the DWR's costs of purchasing electricity under its contracts and a bond charge to pay for the DWR's costs associated with its $11.3 billion bond offering. In December 2004, the CPUC issued a decision on the permanent cost allocation methodology for the DWR's power charge revenue requirements in 2004 and subsequent years, among the three California investor-owned electric utilities. In June 2005, the CPUC issued a decision that modified the permanent cost allocation methodology used to allocate DWR's costs of purchasing electricity among the three California investor-owned electric utilities. This decision allocated 42.2% of the fixed costs of the DWR's revenue requirement to the Utility. In December 2005, the CPUC adopted the DWR's 2006 revenue requirements and allocated $1.7 billion power charge revenue requirements to the Utility. In addition, the 2006 bond charge was set at $0.00485 per kWh. Since the DWR revenue requirement is recovered through the regulatory balancing accounts, any adjustments thereto do not affect the Utility's results of operations.

FERC Transmission Rate Cases

The Utility's electric transmission revenues and wholesale and retail transmission rates are subject to authorization by the FERC. On August 1, 2005, the Utility filed an application with the FERC requesting rates that would provide a revenue requirement increase of approximately $110 million, or 20%, over current retail transmission rates. The FERC accepted the filing and suspended the requested rate changes for five months, to become effective March 1, 2006, subject to refund. The Utility is currently engaged in settlement negotiations with interveners in this case. PG&E Corporation and the Utility are unable to predict what amount of revenue requirements the FERC will authorize, when a final decision will be received from the FERC, or the impact it will have on the results of operations or financial condition.

Scheduling Coordinator Costs

Before the ISO commenced operation in 1998, the Utility had entered into several wholesale electric transmission contracts with various governmental entities. After the ISO began operations, the Utility served as the scheduling coordinator, or SC, with the ISO for these existing wholesale transmission customers. The ISO billed the Utility for providing certain services associated with this scheduling. These ISO charges are referred to as "SC costs." The SC costs were historically tracked in the transmission revenue balancing account, or TRBA, in order to recover the SC costs from retail and new wholesale transmission customers, or TO Tariff customers. In 1999, a FERC administrative law judge ruled that the Utility could not recover the SC costs through the TRBA and instead should seek to recover them from the existing wholesale transmission customers.

In January 2000, the FERC accepted a filing by the Utility to establish the Scheduling Coordinator Services, or SCS Tariff, to serve as an alternative mechanism for recovery of the SC costs from existing wholesale transmission customers if the Utility was ultimately unable to recover these costs in the TRBA.

In August 2002, the FERC ruled that the Utility should refund to TO Tariff customers the SC costs that the Utility collected from them through the TRBA. In December 2002, the Utility appealed the FERC's decision in the United States Court of Appeals for the District of Columbia Circuit, or D.C. Circuit. In the absence of an order from the FERC granting recovery of these costs in the TRBA, the Utility made accounting entries in September 2002 to remove the SC costs from the TRBA and reflect the SC costs as accounts receivable under the SCS Tariff.

In October 2004, the FERC issued an order finding that the Utility could recover the SC costs from the existing wholesale customers. The Utility began billing the existing wholesale customers in June 2004 for SC charges retroactive to March 31, 1998 based on the FERC's initial decision issued in May 2004. Before the FERC hearing to address the allocation of costs to SC customers began in May 2005, the Utility settled with six of these eight wholesale transmission customers. The hearing with the remaining two wholesale customers lasted until June 2005.

In July 2005, the D.C. Circuit issued an order finding that the FERC had erred in its decision that the Utility could not recover the SC costs through the TRBA. The D.C. Circuit held that the Utility was not barred from recovering the SC costs through the TRBA, as had been concluded in August 2002. The D.C. Circuit remanded the matter to the FERC for further action.

On December 20, 2005, the FERC issued an order on remand concluding that the Utility should recover the SC costs through the TRBA mechanism or through bilateral agreements with the existing wholesale transmission customers. The FERC also held that the ISO tariff does not specify recovery of the SC costs through any other rate recovery mechanism and terminated the SCS Tariff proceeding. The FERC also terminated the sub-dockets in the TRBA proceeding under which the Utility was required to provide a refund to TO Tariff customers for the SC costs it had previously tried to recover. For the period April 1998 through December 31, 2005, the Utility was invoiced approximately $135 million by the ISO for SC costs.

On January 19, 2006, the Utility submitted a request for clarification or, alternatively, for rehearing to seek clarification of the December 2005 order. In particular, the Utility asked that the FERC clarify that the Utility can recover through the TRBA all of the costs it incurred as an SC or, alternatively on rehearing, reverse its decision to terminate the SCS Tariff proceeding. The Utility cannot predict what the outcome of this request will be; however, to the extent the Utility can recover all costs it incurred as an SC through the TRBA, the outcome is not expected to have a material adverse effect on its results of operations or financial condition.

Spent Nuclear Fuel Storage Proceedings

Under the Nuclear Waste Policy Act of 1982, the Department of Energy, or the DOE, is responsible for the transportation and permanent storage and disposal of spent nuclear fuel and high-level radioactive waste. The Utility has signed a contract with the DOE to provide for the disposal of spent nuclear fuel and high-level radioactive waste from the Utility's two nuclear power facilities at Diablo Canyon. Under the Utility's contract with the DOE, if the DOE completes a storage facility by 2010, the earliest that Diablo Canyon's spent fuel would be accepted for storage or disposal is thought to be 2018. At the projected level of operation for Diablo Canyon, the Utility's current facilities are able to store on-site all spent fuel produced through approximately 2007. In March 2004, the NRC authorized the Utility to build an on-site dry cask storage facility to store spent fuel through approximately 2021 for Unit 1 and to 2024 for Unit 2. Several interveners in that proceeding filed an appeal of the NRC's decision with the U.S. Court of Appeals for the Ninth Circuit, or the Ninth Circuit. The Ninth Circuit heard oral argument on that appeal in October 2005, and a decision is pending. PG&E Corporation and the Utility cannot predict the outcome of this appeal.

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

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

On October 27, 2005, the CPUC approved an April 4, 2005 settlement agreement between the Utility and the ORA. The settlement resolved the Utility's claims for shareholder incentives earned by the Utility for the successful implementation of demand-side management, energy efficiency, and low-income energy efficiency programs for program years 1994 through 2001, which were addressed in the Utility's AEAP. In addition to resolving claims already made in the AEAPs, the settlement resolved all future claims for shareholder incentives relating to past program years that the Utility would otherwise have made in future AEAPs through 2010.

The Utility's total current and future potential shareholder incentive claims total approximately $207 million. Under the settlement agreement, the parties have agreed that the results to date show that the energy savings anticipated in the Utility's shareholder incentive claims are being realized. The decision approved the settlement amount of approximately $186 million of shareholder incentives, which the Utility recognized in electric and natural gas operating revenues in 2005. Of this amount, approximately $160 million will be recovered from electric customers and approximately $26 million will be recovered from gas customers, in proportion to the relative allocations of the original claims. The Utility has already collected $28 million of the $160 million from electric customers.

Energy Recovery Bond Balancing Account

In connection with the Settlement Agreement, PG&E Corporation and the Utility agreed to seek to refinance the unamortized portion of the Settlement Regulatory Asset and associated federal and state income and franchise taxes, in an aggregate principal amount of up to $3.0 billion in two separate series up to one year apart, using a securitized financing supported by a DRC. On February 10, 2005, PERF issued the first series of ERBs of approximately $1.9 billion. The refinancing of the Settlement Regulatory Asset through the issuance of the first series of ERBs resulted in the elimination of the after-tax portion of the Settlement Regulatory Asset on which the Utility was entitled to collect the revenue requirements, including the revenue requirement to recover the 11.22% ROE, associated with the asset. As a result, the Utility's net income for the three- and twelve-month periods ended December 31, 2005 was reduced by approximately $26 million and $99 million, compared to the same periods in 2004, due to the elimination of the 11.22% ROE on the Settlement Regulatory Asset.

On November 9, 2005, PERF issued the second series of ERBs of approximately $844 million to pre-fund the Utility's tax liability that will be due as the Utility collects the DRC from its customers over the terms of ERBs. Until these taxes are fully paid, the Utility will provide customers a carrying cost credit, computed at the Utility's authorized rate of return on rate base, to compensate customers for the use of proceeds from the second series of ERBs as well as the after-tax proceeds of energy supplier refunds used to reduce the size of the second series of ERBs. The equity portion of this carrying cost credit will reduce the Utility's net income. In the fourth quarter of 2005, the Utility's net income was reduced by $9 million as a result of the carrying cost credit. It is estimated that the carrying cost credit will be approximately $125 million in 2006, which will reduce the Utility's 2006 net income by approximately $56 million. The carrying cost credit and the resulting reduction to net income will decline as the taxes are paid, reaching zero in 2012 when the ERBs and related taxes are expected to be paid in full.

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

incurred subsequent to the issuance of the first series of ERBs shall be deducted in order to calculate the net amount of energy supplier refunds.

As of December 31, 2005, the Utility had accrued approximately $1.2 billion of net disputed claims filed by various energy suppliers in its Chapter 11 proceeding. The ERBBA liability balance was approximately $222 million as of December 31, 2005, which includes approximately $170 million credited to the ERBBA as a result of energy supplier settlements and a reserve of approximately $65 million of net interest costs charged to ERBBA related to the net disputed claims for the period between April 12, 2004, the effective date of the Utility's plan of reorganization, and February 10, 2005, when the first series of ERBs was issued, and certain energy supplier refund litigation costs, pending recovery.

Defined Benefit Pension Plan Contribution

In the Utility's last GRC decision in 2004, the CPUC denied the Utility's request to resume pension contributions based on a finding that the funded status of the Utility's pension plan was in excess of 100%. As of January 1, 2005, the funded status of the pension plan fell below 100% to 98.6%. On December 15, 2005, the CPUC issued a decision that authorized the Utility to file an application for a revenue requirement increase to fund the estimated costs of a pension contribution in 2006. The decision also authorized the Utility to make that revenue increase effective in rates on January 1, 2006, subject to refund depending on the outcome of the application. On December 20, 2005, the Utility filed an application for a 2006 pension contribution requesting a revenue requirement increase of $155 million attributable to its distribution and generation operations. In the 2007 GRC application filed on December 2, 2005, the Utility included a request for approval of an annual revenue requirement of $216 million in 2007, 2008 and 2009 to fund pension contributions for the Utility's distribution and generation businesses. If the 2006 pension application is approved by the CPUC in full, the Utility expects the annual pension revenue requirements in 2007, 2008 and 2009 will be reduced from $216 million to reflect that a pension contribution will be made for 2006. A final decision on the 2006 pension contribution application is expected from the CPUC by the third quarter of 2006.

The net total Utility pension contribution for 2006, if approved, will be $250 million, with an associated revenue requirement of approximately $175 million and a capitalized pension contribution of approximately $75 million. The $175 million consists of the $155 million discussed above and approximately $20 million revenue requirements associated with gas transmission and storage, electric transmission, and nuclear decommissioning, which are the subject of other CPUC and FERC proceedings. The Utility is unable to predict the ultimate outcome of these proceedings, or the impact it will have on its financial condition or result of operations.

CPUC Proceeding Regarding Holding Companies and their Affiliates

In October 2005, the CPUC issued an Order Instituting Rulemaking, or OIR, to allow the CPUC to re-examine the relationship between California energy utilities and their parent holding companies and affiliates. The CPUC stated that it issued the OIR in response to the recent enactment by Congress of the Energy Policy Act of 2005, which, among other things, repealed the Public Utility Holding Company Act of 1935 and ordered the FERC to review its rules regarding dispositions, consolidations, or acquisitions made by entities that are subject to the FERC's jurisdiction under the Federal Power Act. The CPUC noted that as a result of these changes, the parent holding companies of the California energy utilities may try to expand the unregulated activities of the utilities' affiliates, may try to merge with or acquire other companies or may be acquired by other companies and that it was necessary for the CPUC to review its existing regulations and to consider whether additional, new rules or regulations are needed. Although the CPUC set forth a preliminary procedural schedule that called for proposed rules to be issued in January 2006 and a final decision to be issued in March 2006, no proposed rules have been released yet. The CPUC stated that it may propose rules to ensure that the California energy utilities retain sufficient capital and the ability to access capital in order to meet their customers' needs, and to address the potential conflicts between the utilities' customers' interests and the parent holding companies' and affiliates' interests

in order to ensure that these conflicts do not undermine the utilities' ability to meet their public service obligations at the lowest possible cost. The CPUC required the California energy utilities and their parent holding companies to submit certain information to the CPUC. After reviewing the information, the CPUC stated that it may propose additional rules or regulations regarding, but not necessarily limited to, (1) reporting requirements for the allocation of capital between utilities and their non-regulated affiliates by the parent holding companies, and (2) changes to the CPUC's affiliate transaction rules.

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

Pending CPUC Investigation

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

The CPUC's February 2005 ruling states, "This fact proceeding will allow the CPUC to investigate whether PG&E's past conduct with regard to billing and collection issues, including its collection of deposits from customers, is consistent with the orders and regulations of the Commission." The ruling further recites that "If the investigation reveals that the conduct of PG&E violated the statutory laws or rules or orders of the Commission, it may levy fines and/or order PG&E to issue refunds."

On February 3, 2006, the CPUC's Consumer Protection and Safety Division, or CPSD, and TURN submitted their reports to the CPUC concluding that the Utility violated applicable tariffs related to delayed and estimated bills. The CPSD recommends that the Utility refund to customers $117 million, plus interest at the three-month commercial paper interest rate, that allegedly was collected in violation of the tariffs. TURN recommends that the Utility refund to customers $53 million, plus interest at the three-month commercial paper interest rate, that allegedly was collected in violation of the tariffs. The two refunds are not additive. The CPSD also recommends that the Utility pay fines of $6.75 million, while TURN recommends fines in the form of a $1 million contribution to REACH (Relief for Energy Assistance through Community Help). Both the CPSD and TURN recommend that refunds and fines be funded by shareholders.

If the CPUC finds that the Utility violated applicable tariffs or the CPUC's orders or rules, the CPUC may seek to order the Utility to refund any amounts collected in violation of tariffs, plus interest, to customers who paid such amounts. In addition, if the CPUC finds that the Utility violated applicable tariffs or the CPUC's orders or rules, the CPUC may seek to impose penalties on the Utility ranging from $500 to $20,000 for each separate violation.

The Utility's response to the reports is due on March 31, 2006, rebuttal testimony is due on May 5, 2006, and hearings are set to begin on May 22, 2006.

PG&E Corporation and the Utility are unable to predict the outcome of this matter. In light of this uncertainty, the outcome could have a material adverse effect on PG&E Corporation's or the Utility's financial condition or results of operations.

RISK MANAGEMENT ACTIVITIES

The Utility and PG&E Corporation, mainly through its ownership of the Utility, are exposed to market risk, which is the risk that changes in market conditions will adversely affect net income or cash flows. PG&E Corporation and the Utility face market risk associated with their operations, financing arrangements, the marketplace for electricity, natural gas, electricity transmission, natural gas transportation and storage, other goods and services, and other aspects of their business. PG&E Corporation and the Utility categorize market risks as price risk and interest rate risk.

Fluctuation in price will not affect earnings and will only temporarily impact cash flow when recovery through regulatory mechanisms is probable. As described above in "Regulatory Matters – Electricity Generation Resources," the Utility is entitled to recover its reasonably incurred wholesale electricity procurement costs. The Utility's natural gas procurement costs for its core customers are recoverable through the CPIM as described below. The Utility's natural gas transportation and storage costs are not fully recoverable through a ratemaking mechanism. The Utility is subject to price and volumetric risk for the portion of intrastate natural gas transportation capacity that is not contracted under fixed reservation charges used by core customers. Movement in interest rates can cause earnings and cash flow to fluctuate.

The Utility actively manages market risks through risk management programs that are designed to support business objectives, reduce costs, discourage unauthorized risk-taking, reduce earnings volatility and manage cash flows. The Utility uses derivative instruments only for non-trading purposes (*i.e.*, risk mitigation) and not for speculative purposes. The Utility's risk management activities include the use of energy and financial instruments, including forward contracts, futures, swaps, options, and other instruments and agreements, most of which are accounted for as derivative instruments. Some contracts are accounted for as leases.

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

PRICE RISK

Electricity Procurement

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

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

- Periodic expirations of existing electricity purchase contracts, or entering into new energy and capacity purchase contracts;
- Fluctuation in the output of hydroelectric and other renewable power facilities owned or under contract;
- Changes in the Utility's customers' electricity demands due to customer and economic growth, weather, implementation of new energy efficiency and demand response programs, and community choice aggregation;
- The reallocation of the DWR power purchase contracts among California investor-owned electric utilities; and
- The acquisition, retirement or closure of generation facilities.

A failure to perform by any of the counterparties to electricity purchase contracts or the DWR allocated contracts would immediately increase the Utility's net open position. If a counterparty failed to perform on their contractual obligation to deliver electricity, then the Utility will be required to procure electricity at current market prices, which may be higher than those originally contracted for. In particular, Calpine Corporation and certain of its subsidiaries that have filed Chapter 11 petitions, or Calpine, have sought to reject certain power purchase contracts under which they provide approximately 13% of the electricity needed by the Utility's customers. A federal district court recently held that it lacks jurisdiction to authorize Calpine to reject the contracts, finding that the FERC has exclusive jurisdiction with respect to the contracts. Calpine has appealed that decision. The Utility has prepared contingency plans to ensure that it has adequate resources under contract or available if Calpine succeeds in terminating contracts that provide electricity to the Utility's customers.

In addition, lengthy, unexpected outages of the Utility's generation or contracted facilities would immediately increase the Utility's net open position. It is possible that the operation of Diablo Canyon may have to be curtailed or halted as early as 2007, if suitable storage facilities are

not available for spent nuclear fuel, which would cause a significant increase in the Utility's net open position. (See "Spent Nuclear Fuel Storage Proceedings" above). The Utility expects to satisfy at least some of the open position through new contracts. In December 2004, the CPUC approved, with certain modifications, the Utility's long-term procurement plan for 2005 through 2014, as discussed above under "Electricity Generation Resources" section of the MD&A.

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

Natural Gas Procurement (Electric Portfolio)

A portion of the Utility's electric portfolio is exposed to natural gas price risk. The Utility manages this risk in accordance with its risk management strategies, which are included in procurement plans approved by the CPUC. Gas price risk is expected to increase when the fixed price amendments to the Utility's contracts with qualifying facility generators expire in July 2006. Following expiration, payments under these contracts will be based on gas price indices. Due to recent natural gas price volatility, the Utility sought changes to its gas hedging strategy for its electric portfolio. On September 22, 2005 the CPUC approved the Utility's proposed electric portfolio gas hedging plan. An updated plan was filed and approved by the CPUC on November 1, 2005. The expenses associated with the hedging plan are expected to be recovered in the ERRA (see the "Electricity Generation Resources" section of this MD&A).

Natural Gas Procurement (Core Customers)

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

Under the CPIM, the Utility's purchase costs for a fixed twelve-month period are compared to an aggregate market-based benchmark based on a weighted average of published monthly and daily natural gas price indices at the points where the Utility typically purchases natural gas. Costs that fall within a tolerance band, which is 99% to 102% of the benchmark, are considered reasonable and are fully recovered in customers' rates. One-half of the costs above 102% of the benchmark are recoverable in customers' rates, and the Utility's customers receive, in their rates, three-fourths of any savings resulting from the Utility's cost of natural gas that is less than 99% of the benchmark. The shareholder award is capped at the lower of 1.5% of total natural gas commodity costs or $25 million. While this cost recovery mechanism remains in place, changes in the price of natural gas are not expected to materially impact net income.

On October 6, 2005, the CPUC approved the Utility's hedging plan for the winters of 2005–06, 2006–07, and 2007–08. Core customers will pay the cost of these hedges and receive any payouts as these transactions are handled outside of the CPIM. The Utility is at risk to the extent that the CPUC may disallow portions of the hedging cost based on its subsequent review of the Utility's performance under the filed plan. As part of the hedging plan, the Utility has also agreed to forego a shareholder award under the CPIM for the 2004–2005 CPIM year.

Nuclear Fuel

The Utility purchases nuclear fuel for Diablo Canyon through contracts with terms ranging from two to five years. These long-term nuclear fuel agreements are with large, well-established international producers in order to diversify its commitments and provide security of supply. These costs are recovered in the ERRA (see the "Electricity Generation Resources" section of this MD&A); therefore, the changes in nuclear fuel prices are not expected to materially impact net income.

Natural Gas Transportation and Storage

The Utility faces price and volumetric risk for the portion of intrastate natural gas transportation capacity that is not contracted under fixed reservation charges used by core customers. Price risk and volumetric risk result from variability in the price of and demand for natural gas transportation and storage services, respectively. Non-core customers contract with the Utility for natural gas transportation and storage, along with natural gas parking and lending (market center) services. Transportation is sold at competitive market-based rates within a cost-of-service tariff framework.

The Utility uses value-at-risk to measure the Utility's exposure to price and volumetric risks that could impact revenues due to changes in market prices, customer demand and weather. Value-at-risk measures this exposure over a rolling 12-month forward period and assumes that the contract positions are held through expiration. This calculation is based on a 99% confidence level, which means that there is a 1% probability that the impact to revenues on a pre-tax basis, over the rolling 12-month forward period, will be at least as large as the reported value-at-risk. Value-at-risk has several limitations as a measure of portfolio risk, including, but not limited to, inadequate indication of the exposure of a portfolio to extreme price movements and not capturing the intra-day risk related to position changes. The Utility's value-at-risk calculated under the methodology described above was approximately $31 million at December 31, 2005. The Utility's high, low, and average value-at-risk during the year ended December 31, 2005 were approximately $43 million, $31 million and $36 million, respectively.

Prior to January 1, 2005, the Utility used value-at-risk to measure the expected maximum change over a one-day period in the rolling 18-month forward value of its transportation and storage portfolio based on a 95% confidence level. Value-at-risk calculated under the methodology used prior to January 1, 2005 has several limitations as a measure of portfolio risk, including, but not limited to, underestimation of the risk of a portfolio with significant options exposure, mismatch of one-day liquidation period assumed in the value-at-risk methodology as compared to the longer term holding period of the storage and transportation portfolio, inadequate indication of the exposure of a portfolio to extreme price movements, and inability to measure intra-day risk from position changes or volumetric uncertainty in the demand for pipeline services. Due to the limitations of this value-at-risk methodology, the Utility enhanced the calculation methodology as described above to (1) capture uncertainty with respect to demand (volumetric uncertainty) for pipeline services, (2) reflect the market conditions in which the pipeline operates by increasing the holding period to 12 months and (3) include the uncertainty associated with the option exposure in the pipeline portfolio.

The Utility's daily value-at-risk for its transportation and storage portfolio calculated under the methodology used prior to January 1, 2005 would have been approximately $14 million at December 31, 2005 and approximately $4 million at December 31, 2004. The Utility's high, low and average transportation and storage value-at-risk during the year ended December 31, 2005 would have been approximately $14 million, $1 million and $3 million, respectively. The Utility's high, low and average transportation and storage value-at-risk during the year ended December 31, 2004 would have been approximately $6 million, $2 million and $4 million, respectively.

Convertible Subordinated Notes

As of December 31, 2005, PG&E Corporation has outstanding $280 million of 9.50% Convertible Subordinated Notes that are scheduled to mature on June 30, 2010. These Convertible Subordinated Notes may be converted (at the option of the holder) at any time prior to maturity into 18,558,655 shares of common stock of PG&E Corporation, at a conversion price of approximately $15.09 per share. The conversion price is subject to adjustment should a significant change occur in the number of PG&E Corporation's outstanding common shares. To date, the conversion price has not required adjustment. In addition, holders of the Convertible Subordinated Notes are entitled to receive "pass-through dividends" at the same payout as common stockholders with the number of shares determined by dividing the principal amount of the Convertible Subordinated Notes by the conversion price. In connection with each common stock dividend that was payable to holders of PG&E Corporation common stock on April 15, July 15, and October 15, 2005,

and January 16, 2006, PG&E Corporation paid approximately $6 million of "pass-through dividends" to the holders of Convertible Subordinated Notes. The holders have a one-time right to require PG&E Corporation to repurchase the Convertible Subordinated Notes on June 30, 2007, at a purchase price equal to the principal amount plus accrued and unpaid interest (including liquidated damages and unpaid "pass-through dividends," if any).

In accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," or SFAS No. 133, the dividend participation rights component is considered to be an embedded derivative instrument and, therefore, must be bifurcated from the Convertible Subordinated Notes and recorded at fair value in PG&E Corporation's Consolidated Financial Statements. Changes in the fair value are recognized in PG&E Corporation's Consolidated Statements of Income as a non-operating expense or income (included in Other expense, net). At December 31, 2005 and 2004, the total estimated fair value of the dividend participation rights component, on a pre-tax basis, was approximately $92 million and $91 million, respectively, of which $22 million and $15 million, respectively, is classified as a current liability (in Current liabilities – Other) and $70 million and $76 million, respectively, is classified as a noncurrent liability (in Noncurrent liabilities – Other). The liability, which was initially recorded in 2004, did not change by a material amount during 2005.

Accelerated Share Repurchase

As discussed under "Liquidity and Financial Resources," in November 2005, PG&E Corporation entered into an ASR with GS&Co. under which PG&E Corporation repurchased 31,650,300 shares of its outstanding common stock at an initial price of $34.75 per share for an aggregate amount including commissions of approximately $1.1 billion. Under the terms of the agreement, certain additional payments may be required by both PG&E Corporation and GS&Co. Most significantly, PG&E Corporation may receive from, or be required to pay to, GS&Co. a price adjustment based on the VWAP of PG&E Corporation common stock over a period of approximately seven months.

PG&E Corporation will receive from, or be required to pay to GS&Co. an additional amount under the ASR if the VWAP during the remaining term of the agreement exceeds the initial price of $34.75. For the remaining term of the agreement, for every $1 that the VWAP during the remaining term of the ASR differs from the initial price of $34.75, PG&E Corporation will owe GS&Co. an additional $24.8 million. Conversely, for every $1 that the VWAP is below $34.75, the amount due from GS&Co. will be reduced by $24.8 million.

The obligation under the price adjustment is not reflected in earnings. As discussed in Note 8, because the price adjustment can be settled at PG&E Corporation's option, in cash, in shares of its common stock, or a combination of the two, PG&E Corporation accounts for its payment obligation as an equity transaction. Until the transaction is completed or terminated, the accounting principles generally accepted in the United States of America, or GAAP, requires PG&E Corporation to assume that it will issue shares to settle its obligation. Accordingly, the number of shares that would be required to satisfy the obligation must be treated as outstanding for purposes of calculating diluted EPS.

INTEREST RATE RISK

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

Interest rate risk sensitivity analysis is used to measure interest rate risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. At December 31, 2005, if interest rates changed by 1% for all current variable rate debt issued by PG&E Corporation and the Utility, the change would affect net income by an immaterial amount, based on net variable rate debt and other interest rate-sensitive instruments outstanding.

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

PG&E Corporation and the Utility account for the financial effects of regulation in accordance with SFAS No. 71. SFAS No. 71 applies to regulated entities whose rates are designed to recover the cost of providing service. SFAS No. 71 applies to all of the Utility's operations except for the operations of a natural gas pipeline. During the first quarter of 2004, the Utility began reapplying SFAS No. 71 to its generation operations.

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

If the Utility determined that it could not apply SFAS No. 71 to its operations or, if under SFAS No. 71 it could not conclude that it is probable that revenues or costs would be recovered or reflected in future rates, the revenues or costs would be charged to income in the period in which they were incurred. If it is determined that a regulatory asset is no longer probable of recovery in rates, then SFAS No. 71 requires that it be written off at that time. At December 31, 2005, PG&E Corporation and the Utility reported regulatory assets (including current regulatory balancing accounts receivable) of approximately $6.3 billion and regulatory liabilities (including current balancing accounts payable) of approximately $4.3 billion.

UNBILLED REVENUES

The Utility records revenue as electricity and natural gas are delivered. Amounts delivered to customers are determined through the systematic readings of customer meters performed on a monthly basis. At the end of each month, the electric and gas usage from the last meter reading is estimated and corresponding unbilled revenue is recorded. The estimate of unbilled revenue is determined by factoring an estimate of the electricity and natural gas load delivered with recent historical usage and rate patterns.

In the following month, the estimate for unbilled revenue is reversed and actual revenue is recorded based on meter readings. The accuracy of the unbilled revenue estimate is affected by factors that include fluctuations in energy demands, weather, and changes in the composition of customer classes. At December 31, 2005, accrued unbilled revenues totaled $679 million.

ENVIRONMENTAL REMEDIATION LIABILITIES

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

At December 31, 2005, the Utility's accrual for undiscounted environmental liability was approximately $469 million. The Utility's undiscounted future costs could increase to as much as $680 million if other potentially responsible parties are not able to contribute to the settlement of these costs or the extent of contamination or necessary remediation is greater than anticipated.

The accrual for undiscounted environmental liability is representative of future events that are likely to occur. In determining maximum undiscounted future costs, events that are possible but not likely are included in the estimation.

ASSET RETIREMENT OBLIGATIONS

The Utility accounts for its long-lived assets under SFAS No. 143, "Accounting for Asset Retirement Obligations," or SFAS No. 143, and Financial Accounting Standards Board, or FASB, Interpretation Number 47, "Accounting for Conditional Asset Retirement Obligations – An Interpretation of SFAS No. 143," or FIN 47. SFAS No. 143 and FIN 47 require that an asset retirement obligation be recorded at fair value in the period in which it is incurred if a reasonable estimate of fair value can be made. In the same period, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. Rate-regulated entities may recognize regulatory assets or liabilities as a result of timing differences between the recognition of costs as recorded in accordance with SFAS No. 143 and FIN 47, and costs recovered through the rate-making process.

The Utility estimates the fair value of asset retirement obligations from calculating the discounted cash flows based on the probability of multiple outcome scenarios that are dependent upon the following components:

- *Inflation adjustment* – The estimated cash flows are adjusted for inflation estimates for labor, equipment, materials, and other disposal costs based on data from regulatory filings including the Nuclear Decommissioning Cost Triennial Proceeding and GRC filings;
- *Discount rate* – The estimated cash flows include contingency factors that were used as a proxy for the market risk premium; and
- *Third-party markup adjustments* – Internal labor costs included in the cash flow calculation were adjusted for costs that a third party would incur in performing the tasks necessary to retire the asset.

Changes in these factors could materially affect the obligation recorded to reflect the ultimate cost associated with retiring the assets under SFAS No. 143 and FIN 47. For example, if the inflation adjustment increased 25 basis points, this would increase the balance for asset retirement obligations by approximately 5.0%. Similarly, an increase in the discount rate by 25 basis points would decrease asset retirement obligations by the same percentage. At December 31, 2005, the Utility's estimated cost of retiring these assets is approximately $1.6 billion.

ACCOUNTING FOR INCOME TAXES

PG&E Corporation and the Utility account for income taxes in accordance with SFAS No. 109, "Accounting for Income Taxes," which requires judgment regarding the potential tax effects of various transactions and ongoing operations to determine obligations owed to tax authorities. Amounts of deferred income tax assets and liabilities, as well as current and noncurrent accruals, involve estimates of the timing and probability of recognition of income and deductions. Actual income taxes could vary from estimated amounts due to the future impacts of various items including changes in tax laws, PG&E Corporation's financial condition in future periods, and the final review of filed tax returns by taxing authorities. As further described in "Note 11: Income Taxes," the IRS has proposed to disallow some deductions in the 2001 and 2002 audit of the consolidated federal income tax returns. The largest of these deductions is for abandoned or worthless assets owned by NEGT and synthetic fuel credits. The IRS began its audit of the 2003 and 2004 tax return in the third quarter of 2005; to date the IRS has not proposed any similar adjustments. As of December 31, 2005, PG&E Corporation and the Utility have accrued approximately $138 million and $52 million, respectively, to cover potential tax obligations and interest relating to the outstanding audits.

PENSION AND OTHER POSTRETIREMENT PLANS

Certain employees and retirees of PG&E Corporation and its subsidiaries participate in qualified and non-qualified non-contributory defined benefit pension plans. Certain retired employees, and their eligible dependents, of PG&E Corporation and its subsidiaries also participate in contributory medical plans, and certain retired employees participate in life insurance plans (referred to collectively as "other benefits"). Amounts that PG&E Corporation and the Utility recognize as costs and obligations to provide pension benefits under SFAS No. 87, "Employers' Accounting for Pensions," or SFAS No. 87, and other benefits under SFAS No. 106, "Employers Accounting for Postretirement Benefits Other Than Pensions," or SFAS No. 106, are based on a variety of factors. These factors include the provisions of the plans, employee demographics and various actuarial calculations, assumptions and accounting mechanisms. Because of the complexity of these calculations, the long-term nature of these obligations and the importance of the assumptions utilized, PG&E Corporation's and the Utility's estimate of these costs and obligations is a critical accounting estimate.

Actuarial assumptions used in determining pension obligations include the discount rate, the average rate of future compensation increases and the expected return on plan assets. Actuarial assumptions used in determining other benefit obligations include the discount rate, the expected return on plan assets and the assumed health care cost trend rate. PG&E Corporation and the Utility review these assumptions on an annual basis and adjust them as necessary. While PG&E Corporation and the Utility believe the assumptions used are appropriate, significant differences in actual experience, plan changes or significant changes in assumptions may materially affect the recorded pension and other benefit obligations and future plan expenses.

In accordance with accounting rules, changes in benefit obligations associated with these assumptions may not be recognized as costs on the income statement. Differences between actuarial assumptions and actual plan results are deferred and are amortized into cost only when the accumulated differences exceed 10% of the greater of the projected benefit obligation or the market-value of the related plan assets. If necessary, the excess is amortized over the average remaining service period of active employees. As such, significant portions of benefit costs recorded in any period may not reflect the actual level of cash benefits provided to plan participants. PG&E Corporation's and the Utility's recorded pension expense totaled $176 million in 2005, $182 million in 2004, and $212 million in 2003, in accordance with the provisions of SFAS No. 87. PG&E Corporation's and the Utility's recorded expense for other postretirement and benefit obligations totaled $55 million in 2005, $78 million in 2004, and $76 million in 2003 in accordance with the provisions of SFAS No. 106. Under SFAS No. 71, regulatory adjustments have been recorded in the Consolidated Statements of Income and Consolidated Balance Sheets of the Utility to reflect the difference between Utility pension expense or income for accounting purposes and Utility pension expense or income for rate-making, which is based on a funding approach. The CPUC has authorized the Utility to recover the costs associated with its other benefits for 1993 and beyond. Recovery is based on the lesser of the amounts collected in rates or the annual contributions on a tax-deductible basis to the appropriate trusts.

PG&E Corporation's and the Utility's funding policy is to contribute tax deductible amounts, consistent with applicable regulatory decisions (including the 2003 GRC), sufficient to meet minimum funding requirements. Based upon current assumptions and available information, PG&E Corporation and the Utility have not identified any minimum funding requirements related to its pension plans, excluding amounts required to fund a voluntary retirement program of approximately $20 million in 2006. PG&E Corporation and the Utility have estimated funding requirements related to their postretirement benefit plans at approximately $60 million in 2006. Contribution estimates for the Utility's pension and postretirement benefit plans after 2006 will be driven by future GRC decisions.

Pension and other benefit funds are held in external trusts. Trust assets, including accumulated earnings, must be used exclusively for pension and other benefit payments. Consistent with the trusts' investment policies, assets are invested in U.S. equities, non-U.S. equities and fixed income securities. Investment securities are exposed to various risks, including interest rate, credit and overall market volatility risks. As a result of these risks, it is reasonably possible that the market values of investment securities could increase or decrease in the near term. Increases or decreases in market values could materially affect the current value of the trusts and, as a result, the future level of pension and other benefit expense.

Expected rates of return on plan assets were developed by determining projected stock and bond returns and then applying these returns to the target asset allocations of the employee benefit trusts, resulting in a weighted average rate of return on plan assets. Fixed income projected returns were based on historical returns for the broad U.S. bond market. Equity returns were based primarily on historical returns of the S&P 500 Index. For the Utility Retirement Plan, the assumed return of 8.0% compares to a ten-year actual return of 9.0%.

The rate used to discount pension and other post-retirement benefit plan liabilities was based on a yield curve developed from the Moody's AA Corporate Bond Index at December 31, 2005. 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 post retirement 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 2005 Pension Cost	Increase in Projected Benefit Obligation at December 31, 2005
Discount rate	(0.5)%	$50	$642
Rate of return on plan assets	(0.5)%	37	–
Rate of increase in compensation	0.5%	29	141

The following reflects the sensitivity of postretirement benefit costs and accumulated benefit obligation to changes in certain actuarial assumptions:

(in millions)	Increase (decrease) in Assumption	Increase in 2005 Post-retirement Benefit Cost	Increase in Accumulated Benefit Obligation at December 31, 2005
Health care cost trend rate	0.5%	$5	$35
Discount rate	(0.5)%	2	64

ACCOUNTING PRONOUNCEMENTS ISSUED BUT NOT YET ADOPTED

Share-Based Payment Transactions

In December 2004, the FASB issued Statement of Financial Accounting Standards, or SFAS, No. 123 (revised December 2004), "Share-Based Payment," or SFAS No. 123R. SFAS No. 123R requires that the cost of all share-based payment transactions be recognized in the financial statements and establishes a fair-value measurement objective in determining the value of such costs. In accordance with SFAS No. 123R, an estimate of forfeitures should be made and compensation expense should be recognized over the requisite service period only for shares that are expected to vest.

PG&E Corporation and the Utility are currently expensing share-based awards other than stock options over the stated vesting period regardless of terms that accelerate vesting upon retirement. Upon adoption of SFAS No. 123R, compensation expense for all awards, including stock options, will be recognized over the shorter of (1) the stated vesting period, or (2) the period from the date of grant through the date the employee is no longer required to provide service to vest.

On April 14, 2005, the Securities and Exchange Commission amended the compliance date and allowed public companies with calendar year-ends to adopt SFAS No. 123R in the first quarter of 2006. The adoption of SFAS No. 123R is not expected to have a material impact on the Consolidated Financial Statements.

Accounting Changes and Error Corrections

In May 2005, the FASB issued FASB Statement No. 154, "Accounting Changes and Error Corrections Disclosure," or SFAS No. 154. SFAS No. 154 replaces Accounting Principles Board, or APB, Opinion No. 20, "Accounting Changes," or APB No. 20, and FASB Statement No. 3, "Reporting Accounting Changes in Interim Financial Statements," or

SFAS No. 3. SFAS No. 154 requires retrospective application to prior periods' financial statements of changes in accounting principle unless it is impracticable. This Statement applies to all voluntary changes in accounting principle. SFAS No. 154 is effective for the first quarter of 2006.

TAXATION MATTERS

The IRS has completed its audit of PG&E Corporation's 1997 and 1998 consolidated federal income tax returns and has assessed additional federal income taxes of approximately $81 million (including interest). PG&E Corporation has filed protests contesting certain adjustments made by the IRS in that audit and currently is discussing these adjustments with the IRS Appeals Office.

The IRS also has completed its audit of PG&E Corporation's 1999 and 2000 consolidated federal income tax returns and refunded $14 million to PG&E Corporation. As a result of the resolution of this audit, in the second quarter of 2005 PG&E Corporation paid the Utility $18 million relating to the Utility matters that had been included in the audit, the Utility reduced its reserve for outstanding tax audits by $11 million and PG&E Corporation recognized tax benefits of $32 million for NEGT-related matters included in the audit.

The IRS is auditing PG&E Corporation's 2001 and 2002 consolidated federal income tax returns. The IRS has indicated that it plans to continue the audit into 2006. At the beginning of its examination, the IRS indicated it would disallow synthetic fuel credits claimed by PG&E Corporation. In January 2006, a partnership which owned a portion of those synthetic fuel facilities received a letter from the IRS disallowing approximately $40 million of synthetic fuel credits. These credits are part of $104 million of synthetic fuel credits claimed by PG&E Corporation in its 2001 and 2002 consolidated federal income tax returns. PG&E Corporation expects the IRS to take similar action with respect to the remaining $64 million of synthetic fuel credits claimed in its 2001 and 2002 consolidated federal income tax returns. In addition, the IRS has proposed to disallow a number of deductions, the largest of which is a deduction for abandoned or worthless assets owned by NEGT. PG&E Corporation believes that it properly reported these transactions in its tax returns and will contest any IRS assessment. If the IRS includes all of its proposed disallowances in the final Revenue Agent Report, the alleged tax deficiency would approximate $452 million. Of this deficiency, approximately $104 million relates to the synthetic fuel credits and approximately $316 million is of a timing nature, which would be refunded to PG&E Corporation in the future. In the second quarter of 2005, PG&E Corporation increased its reserve with respect to NEGT tax issues included in the 2001 and 2002 consolidated federal income tax returns by $32 million.

The IRS began its audit of PG&E Corporation's 2003 and 2004 tax returns in the third quarter of 2005.

During the third quarter of 2005, PG&E Corporation received additional information from NEGT regarding income to be included in PG&E Corporation's 2004 federal income tax return. This information was incorporated in the 2004 tax return, which was filed with the IRS in September 2005. As a result, the 2004 federal income tax liability was reduced by approximately $19 million. In addition, NEGT provided additional information with respect to amounts previously included in PG&E Corporation's 2003 federal income tax return. This change resulted in PG&E Corporation's 2003 federal income tax liability increasing by approximately $6 million. These two adjustments, netting to $13 million, were recognized in income from discontinued operations in the third quarter of 2005.

As of December 31, 2005, PG&E Corporation has accrued approximately $138 million to cover potential tax obligations and interest related to outstanding audits, including the $89 million related to NEGT issues discussed above, and $49 million to cover potential tax obligations related to non-NEGT issues. The increase in PG&E Corporation's accrual at December 31, 2005, compared to December 31, 2004, of approximately $37 million is primarily related to the second quarter increase of $32 million in the accrual for NEGT tax issues included in the 2001–2002 audit discussed above.

As of December 31, 2005, the Utility has accrued approximately $52 million to cover potential tax obligations discussed above, including interest, related to outstanding audits. This represents an $11 million reduction from the accrual at December 31, 2004, and reflects the resolution of the 1999–2000 audit discussed above.

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

ADDITIONAL SECURITY MEASURES

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

ENVIRONMENTAL AND LEGAL MATTERS

PG&E Corporation and the Utility are subject to laws and regulations established both to maintain and improve the quality of the environment. Where PG&E Corporation's and the Utility's properties contain hazardous substances, these laws and regulations may require PG&E Corporation and the Utility to remove those substances or to remedy effects on the environment.

In the normal course of business, PG&E Corporation and the Utility are named as parties in a number of claims and lawsuits. See Note 17 of the Notes to the Consolidated Financial Statements for further discussion. The Utility has accrued approximately $314 million with respect to the Chromium Litigation described in Note 17. PG&E Corporation and the Utility do not believe that the ultimate outcome of the Chromium Litigation will have an additional material adverse impact on their financial condition or results of operations.

RISK FACTORS

RISKS RELATED TO PG&E CORPORATION

PG&E Corporation could be required to contribute capital to the Utility or be denied distributions from the Utility to the extent required by the CPUC's determination of the Utility's financial condition.

In approving the original formation of a holding company for the Utility, the CPUC imposed certain conditions, including an obligation by PG&E Corporation's Board of Directors to give "first priority" to the capital requirements of the Utility, as determined to be necessary and prudent to meet the Utility's obligation to serve and to operate in a prudent and efficient manner. The CPUC later issued decisions in which it adopted an expansive interpretation of PG&E Corporation's obligations under this condition, including the requirement that PG&E Corporation, as well as each of the holding companies of the other major California investor-owned electric utilities, "infuse the utility with all types of capital necessary for the utility to fulfill its obligation to serve." Although the California utility holding companies appealed this interpretation to the California appellate court, the court found that the issue was not ripe for judicial review.

On October 27, 2005, the CPUC instituted a new rulemaking proceeding to allow the CPUC to re-examine the relationship between California energy utilities and their parent holding companies and affiliates. The CPUC stated that it instituted this rulemaking proceeding in response to the recent enactment by Congress of the Energy Policy Act of 2005, which, among other things, repealed the Public Utility Holding Company Act of 1935 and ordered the FERC to review its rules regarding dispositions, consolidations, or acquisitions made by entities that are subject to the FERC's jurisdiction. The CPUC noted that as a result of these changes, the parent holding companies of the California energy utilities may try to expand the unregulated activities of the utilities' affiliates, may try to merge with or acquire other companies or may be acquired by other companies, and that it was necessary for the CPUC to review its existing regulations and to consider whether additional new rules or regulations are needed. The CPUC stated that it may propose rules to ensure that the California energy utilities retain sufficient capital and the ability to access capital in order to meet their customers' needs, and to address the potential conflicts between the utilities' customers' interests and the parent holding companies' and affiliates' interests in order to ensure that these conflicts do not undermine the utilities' ability to meet their public service obligations at the lowest possible cost. The CPUC stated that it may propose additional rules or regulations regarding, but not necessarily limited to, (1) reporting requirements for the allocation of capital between utilities and their non-regulated affiliates by the parent holding companies, and (2) changes to the CPUC's affiliate transaction rules.

Under the CPUC's current interpretation of its existing rules, whenever the Utility's financial health is impaired in the future, PG&E Corporation could be required to infuse the Utility with all types of capital necessary to fulfill its obligation to serve or to operate in a prudent and efficient

manner. These obligations, if ultimately upheld by the courts, could materially restrict PG&E Corporation's ability to meet other obligations. In addition, new CPUC rules may restrict how PG&E Corporation deploys capital among the Utility and non-regulated affiliates that PG&E Corporation may have in the future.

Adverse resolution of pending litigation could have a material adverse effect on PG&E Corporation's financial condition and results of operations.

In 2002, the California Attorney General, or AG, and the City and County of San Francisco, or CCSF, filed complaints against PG&E Corporation that allege that PG&E Corporation violated Section 17200 of the California Business and Professions Code by violating various conditions established by the CPUC in decisions approving the formation of holding companies, including the so-called "first priority condition." They allege that past transfers of funds from the Utility to PG&E Corporation during the period 1997 through 2000 (primarily in the form of dividends and stock repurchases), and allegedly from PG&E Corporation to other affiliates of PG&E Corporation, violated these conditions. They also argue that the defendants violated these conditions when PG&E Corporation allegedly failed to provide adequate financial support to the Utility during the California energy crisis in 2000 and 2001. Among other remedies for the alleged violations, the plaintiffs seek restitution of amounts alleged to have been wrongly transferred, civil penalties of $2,500 against each defendant for each violation of Section 17200, a total penalty of not less than $500 million, and costs of suit.

The complaints were originally filed in the San Francisco Superior Court, or Superior Court. In 2003, the U.S. District Court for the Northern District of California, or District Court, found that because the restitution claim, estimated along with CCSF's claims at approximately $5 billion, are the property of the Utility's Chapter 11 estate, the claims were within the jurisdiction of the bankruptcy court overseeing the Utility's Chapter 11 case. Although the District Court confirmed the removal of the restitution claims to the bankruptcy court, the District Court found that the Superior Court retained jurisdiction of the civil penalty claims. On January 10, 2006, the Ninth Circuit issued a decision reversing the District Court's order and finding that the restitution claims could be brought in the Superior Court. PG&E Corporation has filed a petition for rehearing en banc. PG&E Corporation believes that the challenged intercompany transactions were in full compliance with applicable law and CPUC conditions and that the plaintiffs' allegations are without merit. However, there can be no assurance that PG&E Corporation will prevail in these lawsuits.

RISKS RELATED TO THE UTILITY

PG&E Corporation's and the Utility's financial viability depends upon the Utility's ability to recover its costs in a timely manner from the Utility's customers through regulated rates and otherwise execute its business strategy.

The Utility is a regulated entity subject to CPUC jurisdiction in almost all aspects of its business, including the rates, terms and conditions of its services, procurement of electricity and natural gas for its customers, issuance of securities, dispositions of utility assets and facilities, and aspects of the siting and operation of its electricity and natural gas distribution systems. Executing the Utility's business strategy depends on periodic CPUC approvals of these and related matters. The Utility's ongoing financial viability depends on its ability to recover from its customers in a timely manner the Utility's costs, including the costs of electricity and natural gas purchased for its customers, in the Utility's CPUC-approved rates through GRCs and other ratemaking proceedings and its ability to pass through to its customers in rates the Utility's FERC-authorized revenue requirements.

Part of the Utility's business strategy is to achieve operational excellence and improve customer service. During 2005, the Utility identified and has undertaken various initiatives to implement changes to its business processes and systems in an effort to provide better, faster and more cost-effective service to its customers. The Utility plans to achieve its goal while spending within the revenue requirements requested in the 2007 GRC. The Utility's 2007 GRC application includes a proposal to reward or penalize the Utility up to $60 million per year to the extent that the Utility's actual performance exceeds or falls short of pre-set annual performance improvement targets over the 2007–2009 period. In addition, the Utility has proposed a mechanism by which shareholders and customers would share certain earnings and, if earnings fell below a certain level, would share the shortfall in earnings. There can be no assurance that the Utility will be able to achieve the operating and cost efficiencies anticipated or meet the proposed performance targets.

The CPUC also has approved various programs to support public policy goals through the use of customer incentives and subsidies for energy efficiency programs and the development and use of renewable and self-generation technologies. These incentives and subsidies increase the Utility's overall costs which are reflected in rates collected from customers. As rate pressure increases, the risk increases that the CPUC or other state authority will disallow recovery of some of the Utility's other costs based on a determination that such costs were not reasonably incurred or for some other reason, resulting in stranded investment capital.

The Utility's financial viability also depends on its ability to recover in rates an adequate return on the capital invested in its utility assets, including long-term debt and equity. There may be unanticipated changes in operating expenses or capital expenditures, which may result in material differences between forecasted costs used to determine rates and actual costs incurred that in turn, may affect the Utility's ability to earn its authorized rate of return. During the California energy crisis, the Utility was unable to recover in rates the high prices the Utility paid for electricity on the wholesale market, which ultimately caused the Utility to file a petition under Chapter 11. 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, there can be no assurance that the CPUC will find that all of the Utility's costs are reasonable and prudent or will not otherwise take or fail to take actions to the Utility's detriment.

In addition, there can be no assurance that the bankruptcy court or other courts will implement and enforce the terms of the Settlement Agreement and the Utility's plan of reorganization in a manner that would produce the economic results that PG&E Corporation and the Utility intend or anticipate. Further, there can be no assurance that FERC-authorized tariffs will be adequate to cover the related costs. If the Utility is unable to recover any material amount of its costs through its rates in a timely manner, PG&E Corporation's and the Utility's financial condition and results of operations would be materially adversely affected.

The Utility faces significant uncertainties associated with the future level of bundled electric load for which it must procure electric energy and secure generating capacity which could result in unrecoverable costs, as the Utility's "net open position" changes.

The Utility's net open position is the portion of the Utility's responsibility to procure electric capacity and energy for its customers that the Utility has not yet secured. The Utility's net open position could increase or decrease due to a change in the number of the Utility's customers, periodic expirations of existing electricity purchase contracts, entering into new energy and capacity purchase contracts, fluctuation in the output of hydroelectric and other renewable power facilities owned or under contract by the Utility, implementation of new energy efficiency and demand response programs, the reallocation of the DWR power purchase contracts among California investor-owned electric utilities, and the acquisition, retirement or closure of generation facilities. The Utility's net open position would immediately increase if there was an unexpected outage at Diablo Canyon or any of its other significant generation facilities, if the Utility had to cease operations at Diablo Canyon if it were unable to timely complete construction of on-site storage for spent nuclear fuel, or if any of the counterparties to the Utility's electricity purchase contracts or the DWR allocated contracts failed to perform due to bankruptcy or for some other reason. For example, if Calpine is successful in rejecting several contracts under which it provides electricity for the Utility's customers, the Utility's net open position would increase. The Utility would be required to purchase electricity in the wholesale market to meet its net open position. These purchases would be made under contracts priced at the time of execution or, if made in the spot market, at the then-current market price of wholesale electricity. There can be no assurance that sufficient replacement electricity would be available at prices and on terms that the CPUC would find reasonable. The Utility's financial condition and results of operations would be materially adversely affected if it is unable to purchase electricity in the wholesale market at prices or on terms the CPUC finds reasonable or in quantities sufficient to satisfy the Utility's net open position.

In addition, if a material number of the Utility's customers obtain energy from other providers, the Utility's net open position would decrease. As part of California's electricity industry restructuring, the Utility's customers were given the ability to choose to purchase electricity from alternate energy service providers as "direct access" customers. Customers who did not buy electricity from an alternate provider continued to receive electricity procurement, transmission and distribution services, or bundled service, from the Utility. Direct access customers continued to receive transmission and distribution services from the Utility. The CPUC suspended the right of end-user customers to become direct access customers on September 20, 2001, although customers that were then direct access customers have been allowed to remain on direct access. There can be no assurance that direct access will not be re-established in the future either through legislative action or a voter-approved initiative.

Separately, the CPUC has adopted rules to implement California's Assembly Bill 117, which permits California cities and counties to purchase and sell electricity for their residents once they have registered as community choice aggregators. The Utility would continue to provide distribution, metering and billing services to the community choice aggregators' customers. Once registration has occurred, and the applicable community choice aggregator has received CPUC approval for its implementation plan, the community choice aggregator would purchase electricity for all of its residents who do not affirmatively elect to continue to receive electricity from the Utility. The Utility would continue to be the electricity provider of last resort for all customers.

In addition, self-generation by the Utility's customers would decrease the Utility's net open position. The risk of loss of customers through self-generation is increasing as the CPUC has approved various programs to provide self-generation incentives and subsidies to customers to encourage development and use of renewable and distributed generating technologies, such as solar technology.

If the Utility's net open position decreases due to the loss of a material number of customers, the Utility's existing electricity purchase contracts could obligate it to purchase more electricity than the Utility's remaining customers require, the excess of which the Utility would have to sell, possibly at a loss. In addition, excess electricity generated by the Utility's facilities may also have to be sold, possibly at a loss, and costs the Utility may have incurred to develop or acquire new generation resources may not be recoverable. Further, if the Utility must provide electricity to customers discontinuing direct access or electing to leave a community choice aggregator, the Utility's net open position would increase and the Utility may be required to make unanticipated purchases of additional electricity at higher prices. If the CPUC fails to adjust the Utility's rates to reflect the impact of these changes, PG&E Corporation's and the Utility's financial condition and results of operations could be materially adversely affected.

If the Utility is unable to timely meet the applicable resource adequacy requirements adopted by the CPUC, the Utility may be subject to penalties.

California investor-owned electric utilities, electric service providers, and community choice aggregators (but not local publicly owned utilities), are required to achieve an electricity planning reserve margin of 15% to 17% in excess of peak capacity electricity requirements by June 1, 2006. The CPUC can impose a penalty on the load-serving entity if it fails to acquire sufficient capacity to meet resource adequacy requirements. The penalty is equal to three times the cost of the new capacity the deficient load-serving entity should have secured, but for 2006 the penalty is set at one-half of the amount. If the CPUC determines that the Utility has not met the requirements, the Utility could be subject to penalties in an amount determined by the CPUC in accordance with the new penalty provision.

The Utility faces the risk of unrecoverable costs if its customers obtain distribution and transportation services from other providers as a result of municipalization, technological change, or other forms of bypass.

The Utility's customers could bypass its distribution and transportation system by obtaining service from other sources. Forms of bypass of the Utility's electricity distribution system include the construction of duplicate distribution facilities to serve specific existing or new customers, the condemnation of the Utility's distribution facilities by local governments or municipal districts, and other forms of bypass. Bypass of the Utility's system may result in stranded investment capital, loss of customer growth or additional barriers to cost recovery. As an example, the Sacramento Municipal Utility District, or SMUD, voted to proceed with plans to condemn portions of the Utility's electric system within Yolo County which serves approximately 70,000 Utility customers. The South San Joaquin Irrigation District, or SSJID, also has approved plans to condemn portions of the Utility's electric system

within San Joaquin County. SMUD and SSJID have requested approval from their counties' Local Agency Formation Commissions, or LAFCOs, to annex these areas. The LAFCOs are expected to issue decisions in the summer of 2006. Assuming the LAFCOs approve the annexation, SMUD and SSJID still must satisfy a number of other legal steps. SSJID plans to begin service in 2007 and SMUD plans to begin service in 2008. The Utility opposes these efforts as not being in the best interests of the customers within the subject areas, as well as other customers.

In addition, technological changes could result in the development of economically attractive alternatives to purchasing electricity through the Utility's distribution facilities.

The Utility's natural gas transportation facilities could also be at risk of being bypassed by interstate pipeline companies that construct facilities in the Utility's markets or by customers who build pipeline connections that bypass the Utility's natural gas transportation and distribution system, or by customers who use and transport liquefied natural gas, or LNG. As customers and local public officials continue to explore their energy options, these bypass risks may be increasing and may increase further if the Utility's rates exceed the cost of other available alternatives, resulting in stranded investment capital, loss of customer growth and additional barriers to cost recovery.

If the number of the Utility's customers declines due to municipalization, technological changes 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 and results of operations could be materially adversely affected.

Electricity and natural gas markets are highly volatile and insufficient regulatory responsiveness to that volatility could cause events similar to those that led to the filing of the Utility's Chapter 11 petition to occur.

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 market volatility, including:

- Weather;
- Supply and demand;
- The availability of competitively priced alternative energy sources;
- The level of production of natural gas;
- The availability of LNG supplies;
- The price of fuels that are used to produce electricity, including natural gas, crude oil and coal;
- 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.

In addition, after the fixed price provisions of the Utility's power purchase contracts with QFs expire in July 2006, the Utility's exposure to volatility in natural gas prices will increase as QFs will be able to pass on their cost of the natural gas they purchase as fuel for their generating facilities to the Utility.

If wholesale electricity or natural gas prices increase significantly, public pressure or other regulatory or governmental influences or other factors could constrain the willingness or ability of the CPUC to authorize timely recovery of the Utility's costs from customers. If the Utility is unable to recover any material amount of its costs in its rates in a timely manner, PG&E Corporation's and the Utility's financial condition and results of operations would be materially adversely affected.

Increasing natural gas prices may lead to a change in the gas regulatory framework exposing the Utility to greater cost recovery risk.

The current gas regulatory framework focuses on securing short-term natural gas supplies and rapid pass through of natural gas procurement costs to customers. As natural gas prices have become more volatile, protecting customers from large bill fluctuations may require greater price hedging or securing supplies through long-term contracts. The CPUC has been supportive of increased hedging. There may be increasing regulatory pressure on the Utility to enter into long-term contracts to secure firm, long-term natural gas supplies. There can be no assurance that the CPUC in the future will find that the costs of hedging or the long-term contracts are reasonable

The Utility's financial condition and results of operations could be materially adversely affected if it is unable to successfully manage the risks inherent in operating the Utility's facilities.

The Utility owns and operates extensive electricity and natural gas facilities that are interconnected to the U.S. western electricity grid and numerous interstate and continental natural gas pipelines. The operation of the Utility's facilities and the facilities of third parties on which it relies involves numerous risks, including:

- Operating limitations that may be imposed by environmental laws or regulations, including those relating to climate change, or other regulatory requirements;
- Imposition of operational performance standards by agencies with regulatory oversight of the Utility's facilities;
- Environmental and personal injury liabilities;
- Fuel interruptions;
- Blackouts;
- Labor disputes;
- Weather, storms, earthquakes, fires, floods or other natural disasters, war, disease, and other catastrophic events; and
- Explosions, accidents, mechanical breakdowns and other events or hazards that affect demand, result in power outages, reduce generating output or cause damage to the Utility's assets or operations or those of third parties on which it relies.

The occurrence of any of these events could result in lower revenues or increased expenses, or both, that may not be fully recovered through insurance, rates or other means in a timely manner or at all.

Adverse judgments or settlements in the Chromium Litigation cases could materially adversely affect PG&E Corporation's and the Utility's financial condition and results of operations.

The Utility is a named defendant in 12 civil actions currently pending in the Superior Court for the County of Los Angeles relating to alleged chromium contamination. The Chromium Litigation complaints allege personal injuries, wrongful death and loss of consortium and seek unspecified compensatory and punitive damages based on claims arising from alleged exposure to chromium contamination in the vicinity of three of the Utility's natural gas compressor stations. The Utility has entered into a settlement agreement with attorneys for certain plaintiffs to resolve claims brought by approximately 1,100 of the approximately 1,200 plaintiffs for $295 million. If 90% of the settling plaintiffs do not execute releases by September 15, 2006, including a release signed by each of the eighteen plaintiffs scheduled to participate in the first trial, the Utility may, at its option, terminate the settlement agreement. In order to obtain 100% of the settlement funds, plaintiffs' attorneys must submit releases from or on behalf of 100% of the settling plaintiffs. The Utility has accrued approximately $314 million relating to the Chromium Litigation, including estimated liability for the remaining unresolved claims. If sufficient releases are not obtained and the Utility terminates the settlement agreement, the Utility may incur further liability. If the Utility incurs additional material liability in excess of the amount that it currently has reserved on its balance sheet to satisfy chromium-related liabilities and costs, PG&E Corporation's and the Utility's financial condition and results of operations could be materially adversely affected.

The Utility's operations are subject to extensive environmental laws, and changes in, or liabilities under, these laws could adversely affect its financial condition and results of operations.

The Utility's operations are subject to extensive federal, state and local environmental law and permits. Complying with these environmental laws has in the past required significant expenditures for environmental compliance, monitoring and pollution control equipment, as well as for related fees and permits. Moreover, compliance in the future may require significant expenditures relating to water intake or discharge at certain facilities and electric and magnetic fields. The Utility also is subject to significant liabilities related to the investigation and remediation of environmental contamination at the Utility's current and former facilities, as well as at third-party owned sites. Due to the potential for imposition of stricter standards and greater regulation in the future and the possibility that other potentially responsible parties may not be financially able to contribute to cleanup costs, conditions may change or additional contamination may be discovered, the Utility's environmental compliance and remediation costs could increase, and the timing of its capital expenditures in the future may accelerate. If the Utility is unable to recover the costs of complying with environmental laws in its rates in a timely manner, the Utility's financial condition and results of operations could be materially adversely affected. In addition, in the event the Utility must pay materially more than the amount that it currently has reserved on its balance sheet to satisfy its environmental remediation obligations and the Utility is unable to recover these costs from insurance or through rates in a timely manner, PG&E Corporation's and the Utility's financial condition and results of operations 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.

The operation and decommissioning of the Utility's nuclear power plants expose it to potentially significant liabilities and capital expenditures, including those arising from the storage, handling and disposal of radioactive materials and uncertainties related to the regulatory, technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives. The Utility maintains decommissioning trusts and external insurance coverage to reduce the Utility's financial exposure to these risks. However, the costs or damages the Utility may incur in connection with the operation and decommissioning of nuclear power plants could exceed the amount of the Utility's insurance coverage and other amounts set aside for these potential liabilities. In addition, as an operator of two operating nuclear reactor units, the Utility may be required under federal law to pay up to $201.2 million of liabilities arising out of each nuclear incident occurring not only at Diablo Canyon but at any other nuclear power plant in the United States.

On November 18, 2005, the CPUC approved the Utility's application to replace the turbines, steam generators and other equipment at the two nuclear operating units at Diablo Canyon. The Utility plans to replace the steam generators in Unit 2 in 2008 and in Unit 1 in 2009. Under the CPUC decision, the Utility cannot recover costs in excess of $815 million, as adjusted for actual inflation and cost of capital. If the costs do not exceed $706 million, the CPUC does not intend to conduct an after-the-fact reasonableness review of the costs but such a review is not precluded. If the cost exceeds $706 million, or the CPUC later finds that it has reason to believe the costs may be unreasonable regardless of the amount, the entire cost will be subject to a reasonableness review. If the CPUC determines to review the reasonableness of the costs and disallows any material amount of its project costs as unreasonable, PG&E Corporation's and the Utility's financial condition and results of operations would be materially adversely affected.

In addition, the NRC has broad authority under federal law to impose licensing and safety-related requirements upon owners and operators of nuclear power plants. In the event of non-compliance, the NRC has the authority to impose fines or to force a shutdown of the nuclear plant, or both, depending upon the NRC's assessment of the severity of the situation. Safety and security requirements promulgated by the NRC have, in the past, necessitated substantial capital expenditures at Diablo Canyon and additional significant capital expenditures could be required in the future.

If the Utility fails to increase the spent fuel storage capacity at the Utility's Diablo Canyon nuclear power plant by the spring of 2007 and there are no other available spent fuel storage or disposal alternatives, the Utility would be forced to close this plant and would therefore be required to purchase electricity from more expensive sources.

Under the terms of the NRC operating licenses for Diablo Canyon, there must be sufficient storage capacity for the radioactive spent fuel produced by this plant. Under current operating procedures, the Utility believes that the existing spent fuel pools have sufficient capacity to enable the Utility to operate Diablo Canyon until the spring of 2007. Although the Utility is taking actions to increase the Diablo Canyon spent fuel storage capacity and exploring other alternatives, there can be no assurance that the Utility can obtain the final necessary regulatory approvals to expand spent fuel capacity or that other alternatives will be available or implemented in time to avoid a disruption in production or shutdown of one or both units at this plant. As the proposed permanent spent fuel depository at Yucca Mountain, Nevada will not be available by 2007, there will not be any available third-party spent fuel storage facilities. If there is a disruption in production or shutdown of one or both units at this plant, the Utility will need to purchase electricity from more expensive sources.

Acts of terrorism could materially adversely affect PG&E Corporation's and the Utility's financial condition and results of operations.

The Utility's facilities, including its operating and retired nuclear facilities and the facilities of third parties on which it relies, could be targets of terrorist activities. A terrorist attack on the Utility's facilities could result in a full or partial disruption of the Utility's ability to generate, transmit, transport or distribute electricity or natural gas or cause environmental repercussions. Any operational disruption or environmental repercussions could result in a significant decrease in the Utility's revenues or significant reconstruction or remediation costs, which could materially adversely affect PG&E Corporation's and the Utility's financial condition and results of operations.

The Utility's operations are subject to a number of federal and state statutes, CPUC and FERC regulations, rules and orders, and its failure to comply with any of these could materially adversely affect its financial condition and results of operations.

The Utility is obligated to comply in good faith with all applicable statutes, rules, tariffs and orders of the CPUC, the FERC, the NRC, and others relating to the aspects of its electricity and natural gas utility operations which fall within the jurisdictional authority of such regulatory agencies. These include customer billing, customer service, affiliate transactions, vegetation management, and safety and inspection practices. There is a risk that the interpretation and application of these statutes, rules, tariffs and orders may change over time and that the Utility will be determined to have not complied with the new interpretation, exposing the Utility to potential liability for customer refunds, penalties, or other amounts. There is also a risk that as the Utility employs new technologies in an attempt to improve customer service and achieve operational excellence, new information will become available about the Utility's past practices that may lead to the development of new interpretations of existing tariffs or the implementation of new technologies will be found to violate some rule or tariff.

For example, after the CPUC issued an order that the Utility believes re-interpreted an existing tariff regarding delayed and estimated billing, the CPUC initiated an investigation as to whether the Utility had complied with the existing tariff. The CPSD has recommended to the CPUC that the Utility be ordered to refund to customers $117 million, plus interest, and fines of $6.75 million, for alleged violations of the tariff. TURN has recommended that the Utility refund to customers a lesser amount, $53 million,

plus interest, and a fine of $1 million. As another example, the Utility is required to reimburse the California Department of Forestry, or CDF, for fire suppression costs when a fire on wild lands is caused by the Utility's failure to maintain a specified clearance between vegetation and overhead lines. Recently, the CDF has demanded the Utility pay for fire suppression costs regardless of whether the Utility is determined to be at fault in identifying and removing hazard trees.

If it is determined that the Utility did not comply with applicable statutes, rules, tariffs, or orders, and the Utility is ordered to pay a material amount in customer refunds, penalties, or other amounts, PG&E Corporation's and the Utility's financial condition and results of operations would be materially adversely affected.

Changes in, or liabilities under, the Utility's permits, authorizations or licenses could adversely affect PG&E Corporation's and the Utility's financial condition and results of operations.

The Utility is also required to comply with the terms of various permits, authorizations and licenses. These permits, authorizations and licenses may be revoked or modified by the agencies that granted them if facts develop that differ significantly from the facts assumed when they were issued. In addition, discharge permits and other approvals and licenses are often granted for a term that is less than the expected life of the associated facility. Licenses and permits may require periodic renewal, which may result in additional requirements being imposed by the granting agency. In connection with a license renewal, the FERC may impose new license conditions that could, among other things, require increased expenditures or result in reduced electricity output and/or capacity at the facility.

Also, if the Utility is unable to obtain, renew or comply with these governmental permits, authorizations or licenses, or if the Utility is unable to recover any increased costs of complying with additional license requirements or any other associated costs in its rates in a timely manner, PG&E Corporation's and the Utility's financial condition and results of operations could be materially adversely affected.

If the bankruptcy court's confirmation order is overturned or modified on appeal, PG&E Corporation's and the Utility's financial condition and results of operations could be materially adversely affected.

On December 22, 2003, the bankruptcy court confirmed the Utility's plan of reorganization under Chapter 11. The plan of reorganization fully incorporates the Settlement Agreement as a material and integral part of the plan. The two CPUC commissioners who did not vote to approve the Settlement Agreement, or the dissenting commissioners, filed an appeal of the confirmation order in the District Court. On July 15, 2004, the District Court dismissed the appeals filed by the dissenting commissioners. The dissenting commissioners have appealed the District Court's order with the Ninth Circuit. Oral argument in the Ninth Circuit was held on February 13, 2006.

If the bankruptcy court's confirmation of the Utility's plan of reorganization is overturned or modified on appeal, PG&E Corporation's and the Utility's financial condition and results of operations, and the Utility's ability to pay dividends or otherwise make distributions to PG&E Corporation, could be materially adversely affected.

CONSOLIDATED STATEMENTS OF INCOME

PG&E Corporation

(in millions, except per share amounts)	Year ended December 31, 2005	2004	2003
Operating Revenues			
Electric	$ 7,927	$ 7,867	$ 7,582
Natural gas	3,776	3,213	2,853
Total operating revenues	11,703	11,080	10,435
Operating Expenses			
Cost of electricity	2,410	2,770	2,309
Cost of natural gas	2,191	1,724	1,438
Operating and maintenance	3,397	2,865	2,963
Recognition of regulatory assets	–	(4,900)	–
Depreciation, amortization, and decommissioning	1,735	1,497	1,222
Reorganization professional fees and expenses	–	6	160
Total operating expenses	9,733	3,962	8,092
Operating Income	1,970	7,118	2,343
Reorganization interest income	–	8	46
Interest income	80	55	16
Interest expense	(583)	(797)	(1,147)
Other expense, net	(19)	(98)	(9)
Income Before Income Taxes	1,448	6,286	1,249
Income tax provision	544	2,466	458
Income From Continuing Operations	904	3,820	791
Discontinued Operations			
Gain on disposal of NEGT (net of income tax benefit of $13 million in 2005 and income tax expense of $374 million in 2004)	13	684	–
Loss from operations of NEGT (net of income tax benefit of $230 million)	–	–	(365)
Net Income Before Cumulative Effect of Changes in Accounting Principles	917	4,504	426
Cumulative effect of changes in accounting principles of $(5) million in 2003 related to discontinued operations (net of income tax benefit of $3 million in 2003). In 2003, $(1) million related to continuing operations (net of income tax benefit of $1 million)	–	–	(6)
Net Income	$ 917	$ 4,504	$ 420
Weighted Average Common Shares Outstanding, Basic	372	398	385
Earnings Per Common Share from Continuing Operations, Basic	$ 2.37	$ 9.16	$ 1.96
Net Earnings Per Common Share, Basic	$ 2.40	$ 10.80	$ 1.04
Earnings Per Common Share from Continuing Operations, Diluted	$ 2.34	$ 8.97	$ 1.92
Net Earnings Per Common Share, Diluted	$ 2.37	$ 10.57	$ 1.02
Dividends Declared Per Common Share	$ 1.23	$ –	$ –

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

PG&E Corporation

(in millions)	Balance at December 31, 2005	2004
ASSETS		
Current Assets		
Cash and cash equivalents	$ 713	$ 972
Restricted cash	1,546	1,980
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $77 million in 2005 and $93 million in 2004)	2,422	2,085
Regulatory balancing accounts	727	1,021
Inventories:		
Gas stored underground and fuel oil	231	175
Materials and supplies	133	129
Income taxes receivable	21	–
Prepaid expenses and other	187	46
Total current assets	5,980	6,408
Property, Plant and Equipment		
Electric	22,482	21,519
Gas	8,794	8,526
Construction work in progress	738	449
Other	16	15
Total property, plant and equipment	32,030	30,509
Accumulated depreciation	(12,075)	(11,520)
Net property, plant and equipment	19,955	18,989
Other Noncurrent Assets		
Regulatory assets	5,578	6,526
Nuclear decommissioning funds	1,719	1,629
Other	842	988
Total other noncurrent assets	8,139	9,143
TOTAL ASSETS	$ 34,074	$ 34,540

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

PG&E Corporation

(in millions, except share amounts)	Balance at December 31, 2005	2004
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$ 260	$ 300
Long-term debt, classified as current	2	758
Rate reduction bonds, classified as current	290	290
Energy recovery bonds, classified as current	316	–
Accounts payable:		
Trade creditors	980	762
Disputed claims and customer refunds	1,733	2,142
Regulatory balancing accounts	840	369
Other	441	352
Interest payable	473	461
Income taxes payable	–	185
Deferred income taxes	181	394
Other	1,416	905
Total current liabilities	6,932	6,918
Noncurrent Liabilities		
Long-term debt	6,976	7,323
Rate reduction bonds	290	580
Energy recovery bonds	2,276	–
Regulatory liabilities	3,506	4,035
Asset retirement obligations	1,587	1,301
Deferred income taxes	3,092	3,531
Deferred tax credits	112	121
Preferred stock of subsidiary with mandatory redemption provisions (redeemable, 6.30% and 6.57%, no shares outstanding at December 31, 2005, 4,925,000 shares outstanding at December 31, 2004)	–	122
Other	1,833	1,690
Total noncurrent liabilities	19,672	18,703
Commitments and Contingencies (Notes 2, 4, 5, 6, 8, 9, 13, 15 and 17)		
Preferred Stock of Subsidiaries	252	286
Preferred Stock		
Preferred stock, no par value, 80,000,000 shares, $100 par value, 5,000,000 shares, none issued	–	–
Common Shareholders' Equity		
Common stock, no par value, authorized 800,000,000 shares, issued 366,868,512 common and 1,399,990 restricted shares in 2005 and issued 417,014,431 common and 1,601,710 restricted shares in 2004	5,827	6,518
Common stock held by subsidiary, at cost, 24,665,500 shares	(718)	(718)
Unearned compensation	(22)	(26)
Reinvested earnings	2,139	2,863
Accumulated other comprehensive loss	(8)	(4)
Total common shareholders' equity	7,218	8,633
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$34,074	$34,540

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

PG&E Corporation

(in millions)	Year ended December 31, 2005	2004	2003
Cash Flows From Operating Activities			
Net income	$ 917	$ 4,504	$ 420
Gain on disposal of NEGT (net of income tax benefit of $13 million in 2005 and income tax expense of $374 million in 2004)	(13)	(684)	–
Loss from operations of NEGT (net of income tax benefit of $230 million)	–	–	365
Cumulative effect of changes in accounting principles	–	–	6
Net income from continuing operations	904	3,820	791
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, decommissioning and allowance for equity funds used during construction	1,698	1,497	1,222
Recognition of regulatory assets	–	(4,900)	–
Deferred income taxes and tax credits, net	(659)	2,607	190
Other deferred charges and noncurrent liabilities	33	(519)	857
Loss from retirement of long-term debt	–	65	89
Tax benefit from employee stock plans	50	41	–
Gain on sale of assets	–	(19)	(29)
Net effect of changes in operating assets and liabilities:			
Accounts receivable	(245)	(85)	(605)
Inventories	(60)	(12)	(17)
Accounts payable	257	273	403
Accrued taxes/income taxes receivable	(207)	(122)	173
Regulatory balancing accounts, net	254	(590)	(329)
Other current assets	29	760	(84)
Other current liabilities	273	(48)	(6)
Payments authorized by the bankruptcy court on amounts classified as liabilities subject to compromise	–	(1,022)	(87)
Other	82	110	171
Net cash provided by operating activities	2,409	1,856	2,739
Cash Flows From Investing Activities			
Capital expenditures	(1,804)	(1,559)	(1,698)
Net proceeds from sale of assets	39	35	49
Decrease (increase) in restricted cash	434	(1,216)	(237)
Proceeds from nuclear decommissioning trust sales	2,918	1,821	1,087
Purchases of nuclear decommissioning trust investments	(3,008)	(1,972)	(1,230)
Other	23	(27)	31
Net cash used in investing activities	(1,398)	(2,918)	(1,998)
Cash Flows From Financing Activities			
Net borrowings under accounts receivable facility and working capital facility	260	300	–
Net repayments under working capital facility	(300)	–	–
Proceeds from issuance of long-term debt, net of issuance costs of $3 million in 2005 and $107 million in 2004	451	7,742	581
Proceeds from issuance of energy recovery bonds, net of issuance costs of $21 million in 2005	2,711	–	–
Long-term debt matured, redeemed or repurchased	(1,556)	(9,054)	(1,068)
Rate reduction bonds matured	(290)	(290)	(290)
Energy recovery bonds matured	(140)	–	–
Preferred stock with mandatory redemption provisions redeemed	(122)	(15)	–
Preferred stock without mandatory redemption provisions redeemed	(37)	–	–
Common stock issued	243	162	166
Common stock repurchased	(2,188)	(378)	–
Preferred stock dividends paid	(16)	(90)	–
Common stock dividends paid	(334)	–	–
Other	48	(1)	(4)
Net cash used in financing activities	(1,270)	(1,624)	(615)
Net change in cash and cash equivalents	(259)	(2,686)	126
Cash and cash equivalents at January 1,	972	3,658	3,532
Cash and cash equivalents at December 31,	$ 713	$ 972	$ 3,658
Supplemental disclosures of cash flow information			
Cash received for:			
Reorganization interest income	$ –	$ 16	$ 39
Cash paid for:			
Interest (net of amounts capitalized)	403	646	866
Income taxes paid (refunded), net	1,392	128	(91)
Reorganization professional fees and expenses	–	61	99
Supplemental disclosures of noncash investing and financing activities			
Common stock dividends declared but not yet paid	$ 115	$ –	$ –
Transfer of liabilities and other payables subject to compromise (to) from operating assets and liabilities	–	(2,877)	181

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

PG&E Corporation

(in millions, except share amounts)	Common Stock Shares	Common Stock Amount	Common Stock Held by Subsidiary	Unearned Compensation	Reinvested Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Total Common Shareholders' Equity	Comprehensive Income (Loss)
Balance at December 31, 2002	405,486,015	$6,274	$(690)	$ –	$(1,878)	$(93)	$ 3,613	
Net income	–	–	–	–	420	–	420	$ 420
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133 (net of income tax benefit of $10 million)	–	–	–	–	–	(8)	(8)	(8)
Retirement plan remeasurement (net of income tax benefit of $3 million)	–	–	–	–	–	(4)	(4)	(4)
Net reclassification to earnings (net of income tax expense of $27 million)	–	–	–	–	–	17	17	17
Foreign currency translation adjustment (net of income tax expense of $5 million)	–	–	–	–	–	3	3	3
Comprehensive income								$ 428
Common stock issued	8,796,632	166	–	–	–	–	166	
Common stock warrants exercised	702,367	–	–	–	–	–	–	
Common restricted stock issued	1,590,010	28	–	(28)	–	–	–	
Common restricted stock cancelled	(54,742)	(1)	–	1	–	–	–	
Common restricted stock amortization	–	–	–	7	–	–	7	
Other	–	1	–	–	–	–	1	
Balance at December 31, 2003	416,520,282	6,468	(690)	(20)	(1,458)	(85)	4,215	
Net income	–	–	–	–	4,504	–	4,504	$4,504
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133 (net of income tax expense of $2 million)	–	–	–	–	–	3	3	3
NEGT losses reclassified to earnings upon elimination of equity interest by PG&E Corporation (net of income tax expense of $43 million)	–	–	–	–	–	77	77	77
Other	–	–	–	–	–	1	1	1
Comprehensive income								$4,585
Common stock issued	8,410,058	162	–	–	–	–	162	
Common stock repurchased	(10,783,200)	(167)	–	–	(183)	–	(350)	
Common stock held by subsidiary	–	–	(28)	–	–	–	(28)	
Common stock warrants exercised	4,003,812	–	–	–	–	–	–	
Common restricted stock issued	498,910	16	–	(16)	–	–	–	
Common restricted stock cancelled	(33,721)	(1)	–	1	–	–	–	
Common restricted stock amortization	–	–	–	9	–	–	9	
Tax benefit from employee stock plans	–	41	–	–	–	–	41	
Other	–	(1)	–	–	–	–	(1)	
Balance at December 31, 2004	418,616,141	6,518	(718)	(26)	2,863	(4)	8,633	
Net income	–	–	–	–	917	–	917	$ 917
Minimum pension liability adjustment (net of income tax benefit of $3 million)	–	–	–	–	–	(4)	(4)	(4)
Comprehensive income								$ 913
Common stock issued	10,264,535	247	–	–	–	–	247	
Common stock repurchased	(61,139,700)	(998)	–	–	(1,190)	–	(2,188)	
Common stock warrants exercised	295,919	–	–	–	–	–	–	
Common restricted stock issued	347,710	13	–	(13)	–	–	–	
Common restricted stock cancelled	(116,103)	(4)	–	4	–	–	–	
Common restricted stock amortization	–	–	–	13	–	–	13	
Common stock dividends paid	–	–	–	–	(334)	–	(334)	
Common stock dividends declared but not yet paid	–	–	–	–	(115)	–	(115)	
Tax benefit from employee stock plans	–	50	–	–	–	–	50	
Other	–	1	–	–	(2)	–	(1)	
Balance at December 31, 2005	368,268,502	$5,827	$(718)	$(22)	$ 2,139	$ (8)	$ 7,218	

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF INCOME

Pacific Gas and Electric Company

(in millions)	Year ended December 31, 2005	2004	2003
Operating Revenues			
Electric	$ 7,927	$ 7,867	$ 7,582
Natural gas	3,777	3,213	2,856
Total operating revenues	11,704	11,080	10,438
Operating Expenses			
Cost of electricity	2,410	2,770	2,319
Cost of natural gas	2,191	1,724	1,467
Operating and maintenance	3,399	2,842	2,935
Recognition of regulatory assets	—	(4,900)	—
Depreciation, amortization and decommissioning	1,734	1,494	1,218
Reorganization professional fees and expenses	—	6	160
Total operating expenses	9,734	3,936	8,099
Operating Income	1,970	7,144	2,339
Reorganization interest income	—	8	46
Interest income	76	42	7
Interest expense (non-contractual interest expense of $31 million in 2004 and $131 million in 2003)	(554)	(667)	(953)
Other income, net	16	16	13
Income Before Income Taxes	1,508	6,543	1,452
Income tax provision	574	2,561	528
Net Income Before Cumulative Effect of a Change in Accounting Principle	934	3,982	924
Cumulative effect of a change in accounting principle (net of income tax benefit of $1 million in 2003)	—	—	(1)
Net Income	934	3,982	923
Preferred stock dividend requirement	16	21	22
Income Available for Common Stock	$ 918	$ 3,961	$ 901

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

Pacific Gas and Electric Company

(in millions)	Balance at December 31, 2005	2004
ASSETS		
Current Assets		
Cash and cash equivalents	$ 463	$ 783
Restricted cash	1,546	1,980
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $77 million in 2005 and $93 million in 2004)	2,422	2,085
Related parties	3	2
Regulatory balancing accounts	727	1,021
Inventories:		
Gas stored underground and fuel oil	231	175
Materials and supplies	133	129
Income taxes receivable	48	–
Prepaid expenses and other	183	43
Total current assets	5,756	6,218
Property, Plant and Equipment		
Electric	22,482	21,519
Gas	8,794	8,526
Construction work in progress	738	449
Total property, plant and equipment	32,014	30,494
Accumulated depreciation	(12,061)	(11,507)
Net property, plant and equipment	19,953	18,987
Other Noncurrent Assets		
Regulatory assets	5,578	6,526
Nuclear decommissioning funds	1,719	1,629
Related parties receivable	23	–
Other	754	942
Total other noncurrent assets	8,074	9,097
TOTAL ASSETS	$ 33,783	$ 34,302

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, 2005	2004
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$ 260	$ 300
Long-term debt, classified as current	2	757
Rate reduction bonds, classified as current	290	290
Energy recovery bonds, classified as current	316	–
Accounts payable:		
Trade creditors	980	762
Disputed claims and customer refunds	1,733	2,142
Related parties	37	20
Regulatory balancing accounts	840	369
Other	423	337
Interest payable	460	461
Income taxes payable	–	102
Deferred income taxes	161	377
Other	1,255	869
Total current liabilities	6,757	6,786
Noncurrent Liabilities		
Long-term debt	6,696	7,043
Rate reduction bonds	290	580
Energy recovery bonds	2,276	–
Regulatory liabilities	3,506	4,035
Asset retirement obligations	1,587	1,301
Deferred income taxes	3,218	3,629
Deferred tax credits	112	121
Preferred stock with mandatory redemption provisions (redeemable, 6.30% and 6.57%, no shares outstanding at December 31, 2005 and 4,925,000 shares outstanding at December 31, 2004)	–	122
Other	1,691	1,555
Total noncurrent liabilities	19,376	18,386
Commitments and Contingencies (Notes 2, 4, 5, 6, 8, 9, 13, 15 and 17)		
Shareholders' Equity		
Preferred stock without mandatory redemption provisions:		
Nonredeemable, 5% to 6%, outstanding 5,784,825 shares	145	145
Redeemable, 4.36% to 5.00%, outstanding 4,534,958 shares in 2005 and 4.36% to 7.04%, outstanding 5,973,456 shares in 2004	113	149
Common stock, $5 par value, authorized 800,000,000 shares, issued 279,624,823 shares in 2005 and issued 321,314,760 shares in 2004	1,398	1,606
Common stock held by subsidiary, at cost, 19,481,213 shares	(475)	(475)
Additional paid-in capital	1,776	2,041
Reinvested earnings	4,702	5,667
Accumulated other comprehensive loss	(9)	(3)
Total shareholders' equity	7,650	9,130
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$33,783	$34,302

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Pacific Gas and Electric Company

(in millions)	Year ended December 31, 2005	2004	2003
Cash Flows From Operating Activities			
Net income	$ 934	$ 3,982	$ 923
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, decommissioning and allowance for equity funds used during construction	1,697	1,494	1,218
Recognition of regulatory assets	–	(4,900)	–
Deferred income taxes and tax credits, net	(636)	2,580	(75)
Other deferred charges and noncurrent liabilities	21	(391)	581
Cumulative effect of a change in accounting principle	–	–	1
Net effect of changes in operating assets and liabilities:			
Accounts receivable	(245)	(85)	(590)
Inventories	(60)	(12)	(17)
Accounts payable	257	273	507
Accrued taxes/income taxes receivable	(150)	52	48
Regulatory balancing accounts, net	254	(590)	(329)
Other current assets	2	55	12
Other current liabilities	273	395	17
Payments authorized by the bankruptcy court on amounts classified as liabilities subject to compromise	–	(1,022)	(87)
Other	19	7	14
Net cash provided by operating activities	2,366	1,838	2,223
Cash Flows From Investing Activities			
Capital expenditures	(1,803)	(1,559)	(1,698)
Net proceeds from sale of assets	39	35	49
Decrease (increase) in restricted cash	434	(1,577)	(253)
Proceeds from nuclear decommissioning trust sales	2,918	1,821	1,087
Purchases of nuclear decommissioning trust investments	(3,008)	(1,972)	(1,230)
Other	61	(27)	29
Net cash used in investing activities	(1,359)	(3,279)	(2,016)
Cash Flows From Financing Activities			
Net borrowings under accounts receivable facility and working capital facility	260	300	–
Net repayments under working capital facility	(300)	–	–
Proceeds from issuance of long-term debt, net of issuance costs of $3 million in 2005 and $107 million in 2004	451	7,742	–
Proceeds from issuance of energy recovery bonds, net of issuance costs of $21 million in 2005	2,711	–	–
Long-term debt matured, redeemed or repurchased	(1,554)	(8,402)	(281)
Rate reduction bonds matured	(290)	(290)	(290)
Energy recovery bonds matured	(140)	–	–
Preferred stock dividends paid	(16)	(90)	–
Common stock dividends paid	(445)	–	–
Preferred stock with mandatory redemption provisions redeemed	(122)	(15)	–
Preferred stock without mandatory redemption provisions redeemed	(37)	–	–
Common stock repurchased	(1,910)	–	–
Other	65	–	–
Net cash used in financing activities	(1,327)	(755)	(571)
Net change in cash and cash equivalents	(320)	(2,196)	(364)
Cash and cash equivalents at January 1,	783	2,979	3,343
Cash and cash equivalents at December 31,	$ 463	$ 783	$ 2,979
Supplemental disclosures of cash flow information			
Cash received for:			
Reorganization interest income	$ –	$ 16	$ 39
Cash paid for:			
Interest (net of amounts capitalized)	390	512	773
Income taxes paid, net	1,397	109	648
Reorganization professional fees and expenses	–	61	99
Supplemental disclosures of noncash investing and financing activities			
Transfer of liabilities and other payables subject to compromise (to) from operating assets and liabilities	$ –	$(2,877)	$ 181
Equity contribution for settlement of plan of reorganization, or POR, payable	–	(129)	–

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

Pacific Gas and Electric Company

(in millions, except share amounts)	Preferred Stock Without Mandatory Redemption Provisions	Common Stock	Additional Paid-in Capital	Common Stock Held by Subsidiary	Reinvested Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity	Comprehensive Income (Loss)
Balance at December 31, 2002	**$294**	**$1,606**	**$1,964**	**$(475)**	**$ 805**	**$–**	**$ 4,194**	
Net income	–	–	–	–	923	–	923	$ 923
Retirement plan remeasurement (net of income tax benefit of $2 million)	–	–	–	–	–	(3)	(3)	(3)
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133 (net of income tax benefit of $2 million)	–	–	–	–	–	(3)	(3)	(3)
Comprehensive income								$ 917
Preferred stock dividend	–	–	–	–	(22)	–	(22)	
Balance at December 31, 2003	**294**	**1,606**	**1,964**	**(475)**	**1,706**	**(6)**	**5,089**	
Net income	–	–	–	–	3,982	–	3,982	$3,982
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133 (net of income tax expense of $2 million)	–	–	–	–	–	3	3	3
Comprehensive income								$3,985
Equity contribution for settlement of POR payable (net of income taxes of $52 million)	–	–	77	–	–	–	77	
Preferred stock dividend	–	–	–	–	(21)	–	(21)	
Balance at December 31, 2004	**294**	**1,606**	**2,041**	**(475)**	**5,667**	**(3)**	**9,130**	
Net income	–	–	–	–	934	–	934	$ 934
Minimum pension liability adjustment (net of income tax benefit of $4 million)	–	–	–	–	–	(6)	(6)	(6)
Comprehensive income								$ 928
Common stock repurchased	–	(208)	(266)	–	(1,436)	–	(1,910)	
Common stock dividend	–	–	–	–	(445)	–	(445)	
Preferred stock redeemed	(36)	–	1	–	(2)	–	(37)	
Preferred stock dividend	–	–	–	–	(16)	–	(16)	
Balance at December 31, 2005	**$258**	**$1,398**	**$1,776**	**$(475)**	**$ 4,702**	**$(9)**	**$ 7,650**	

See accompanying Notes to the Consolidated Financial Statements.

NOTE 1: ORGANIZATION AND BASIS OF PRESENTATION

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

As discussed further in Note 15, on April 12, 2004, the Utility's plan of reorganization under the provisions of Chapter 11 of the U.S. Bankruptcy Code, or Chapter 11, became effective, at which time the Utility emerged from Chapter 11.

National Energy & Gas Transmission, Inc., or NEGT, formerly known as PG&E National Energy Group, Inc., was the other significant subsidiary of PG&E Corporation until the effective date of NEGT's reorganization plan on October 29, 2004. NEGT was incorporated on December 18, 1998, as a wholly owned subsidiary of PG&E Corporation. On July 8, 2003, NEGT filed a voluntary petition for relief under Chapter 11. For the reasons described below in Note 7, PG&E Corporation considered NEGT to be an abandoned asset under Statement of Financial Accounting Standards, or SFAS, No. 144, "Accounting for Impairment or Disposal of Long-Lived Assets," and, as a result, the operations of NEGT prior to July 8, 2003 and for all prior periods, are reflected as discontinued operations in the Consolidated Financial Statements. In addition, as discussed in Note 7, effective July 8, 2003, PG&E Corporation no longer consolidated the earnings and losses of NEGT or its subsidiaries and began accounting for its ownership interest in NEGT using the cost method, under which PG&E Corporation's investment in NEGT is reflected as a single amount within the December 31, 2003 Consolidated Balance Sheet of PG&E Corporation. On October 29, 2004, NEGT's plan of reorganization became effective and NEGT emerged from Chapter 11, at which time PG&E Corporation's equity interest in NEGT was cancelled.

This is a combined annual report of PG&E Corporation and the Utility. Therefore, the Notes to the Consolidated Financial Statements apply to both PG&E Corporation and the Utility. PG&E Corporation's Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries. The Utility's Consolidated Financial Statements include its accounts and those of its wholly owned and controlled subsidiaries and variable interest entities for which it is subject to a majority of the risk of loss or gain. All intercompany transactions have been eliminated from the Consolidated Financial Statements.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America, or GAAP, requires management to make estimates and assumptions. These estimates and assumptions affect the reported amounts of revenues, expenses, assets and liabilities and the disclosure of contingencies and include, but are not limited to, estimates and assumptions used in determining the Utility's regulatory asset and liability balances based on probability assessments of regulatory recovery, revenues earned but not yet billed (including delayed billings), disputed claims, asset retirement obligations, allowance for doubtful accounts receivable, provisions for losses that are deemed probable from environmental remediation liabilities, pension liabilities, mark-to-market accounting under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, or SFAS No. 133, income tax related liabilities, litigation, and the Utility's review for impairment of long-lived assets and certain identifiable intangibles to be held and used whenever events or changes in circumstances indicate that the carrying amount of its assets might not be recoverable. As these estimates and assumptions involve judgments on a wide range of factors, including future regulatory decisions and economic conditions that are difficult to predict, actual results could differ from these estimates. PG&E Corporation's and the Utility's Consolidated Financial Statements reflect all adjustments that management believes are necessary for the fair presentation of their financial position and results of operations for the periods presented.

During the Utility's Chapter 11 proceeding, PG&E Corporation's and the Utility's Consolidated Financial Statements were presented in accordance with the American Institute of Certified Public Accountants' Statement of Position 90-7, "Financial Reporting by Entities in Reorganization Under the Bankruptcy Code," or SOP 90-7. Under SOP 90-7, certain claims against the Utility existing before the Utility filed its Chapter 11 petition were classified as liabilities subject to compromise on PG&E Corporation's and the Utility's Consolidated Balance Sheets. Additionally, professional fees and expenses directly related to the Utility's Chapter 11 proceeding and interest income on funds accumulated during the Chapter 11 proceedings were reported separately as reorganization items.

The Utility discontinued the application of SOP 90-7 upon its emergence from Chapter 11 on April 12, 2004. The Consolidated Financial Statements as of and for the year ending December 31, 2003, have been presented in accordance with SOP 90-7. Although the Utility emerged from Chapter 11 on April 12, 2004, the bankruptcy court retained jurisdiction, among other things, to resolve disputed claims made in the Chapter 11 case. Upon the April 12, 2004 effective date of the Utility's plan of reorganization, $1.8 billion was deposited into escrow, pending the resolution of disputed claims, and was classified as restricted cash in current assets on PG&E Corporation's and the Utility's December 31, 2004 Consolidated Balance Sheets. As discussed in Note 15 of the Notes to the Consolidated Financial Statements, the Utility held $1.3 billion in escrow for the payment of the remaining disputed claims as of December 31, 2005. The related remaining pre-petition disputed claims are subject to resolution by the bankruptcy court and are classified as current liabilities on the Consolidated Balance Sheets at December 31, 2005 and 2004.

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

CASH AND CASH EQUIVALENTS

Invested cash and other short-term investments with original maturities of three months or less are considered cash equivalents. Cash equivalents are stated at cost, which approximates fair value. PG&E Corporation and the Utility primarily invest their cash in money market funds and in short-term obligations of the U.S. government and its agencies.

PG&E Corporation had one account balance and the Utility had four account balances that were each greater than 10% of PG&E Corporation's and the Utility's total cash and cash equivalents balance at December 31, 2005.

RESTRICTED CASH

Restricted cash includes Utility amounts held in escrow as required by the bankruptcy court related to remaining disputed Chapter 11 claims and collateral required by the California Independent System Operator, or ISO, the State of California and other counterparties. The Utility also provides deposits to counterparties in the normal course of operations and under certain third-party agreements.

ALLOWANCE FOR DOUBTFUL ACCOUNTS

PG&E Corporation and the Utility recognize an allowance for doubtful accounts to record accounts receivable at estimated net realizable value. The allowance is determined based upon a variety of factors, including historical write-off experience, delinquency rates, current economic conditions and assessment of customer collectibility. If circumstances related to the Utility's assumptions change, recoverability estimates are adjusted accordingly. The write-off of customer accounts receivable is recovered in rates, limited to an amount approved by the CPUC, with any excess being borne by shareholders. Customer accounts receivable are generally written off six months after the date of the final bill.

INVENTORIES

Inventories include materials, supplies and gas stored underground and are valued at average cost. Materials and supplies are charged to inventory when purchased and then

expensed or capitalized to plant, as appropriate, when installed. Materials provisions are made for obsolete inventory. Gas stored underground is charged to inventory when purchased and then expensed when distributed to customers.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are reported at their original cost. Original cost includes:

- Labor and materials;
- Construction overhead; and
- Allowance for funds used during construction, or AFUDC.

AFUDC

AFUDC, or allowance for funds used during construction, is the estimated cost of debt and equity funds used to finance regulated plant additions that is allowed to be recorded as part of the cost of construction projects. AFUDC is recoverable from customers through rates once the property is placed in service. The Utility recorded AFUDC of approximately $51 million during 2005 and $32 million during 2004. PG&E Corporation on a stand-alone basis did not have any capitalized interest or AFUDC in 2005 and 2004.

Depreciation

The Utility's composite depreciation rate was 3.28% in 2005, and 3.42% in 2004 and 2003.

	Gross Plant	
(in millions)	As of December 31, 2005	Estimated Useful Lives
Electricity generating facilities	$ 1,929	15 to 44 years
Electricity distribution facilities	14,551	16 to 58 years
Electricity transmission	3,892	40 to 70 years
Natural gas distribution facilities	4,838	23 to 54 years
Natural gas transportation	2,948	25 to 45 years
Natural gas storage	47	25 to 48 years
Other	3,071	5 to 40 years
Total	$31,276	

The useful lives of the Utility's property, plant and equipment are authorized by the CPUC and the FERC and depreciation expense is included within the recoverable costs of service included in rates charged to customers. Depreciation expense includes a component for the original cost of assets and a component for estimated future removal costs, net of any salvage value at retirement. The Utility has a separate rate it collects from customers for the accrual of its recorded obligation for nuclear decommissioning, which is included in depreciation, amortization and decommissioning expense in the accompanying Consolidated Statements of Income.

PG&E Corporation and the Utility charge the original cost of retired plant less salvage value to accumulated depreciation upon retirement of plant in service for the Utility's lines of business that apply Statement of Financial Accounting Standards, or SFAS, No. 71, "Accounting for the Effects of Certain Types of Regulation," as amended, or SFAS No. 71, which include electricity and natural gas distribution, electricity generation and transmission, and natural gas transportation and storage. PG&E Corporation and the Utility expense repair and maintenance costs as incurred.

Nuclear Fuel

Property, plant and equipment also includes nuclear fuel inventories. Stored nuclear fuel inventory is stated at weighted average cost. Nuclear fuel in the reactor is expensed based on the amount of energy output.

Capitalized Software Costs

PG&E Corporation and the Utility capitalize costs incurred during the application development stage of internal use software projects to property, plant and equipment. Capitalized software costs totaled $201 million at December 31, 2005 and $231 million at December 31, 2004, net of accumulated amortization of approximately $168 million at December 31, 2005 and $196 million at December 31, 2004. PG&E Corporation and the Utility expense capitalized software costs ratably over the expected lives of the software ranging from 3 to 15 years, commencing upon operational use.

REGULATION AND STATEMENT OF FINANCIAL ACCOUNTING STANDARDS NO. 71

PG&E Corporation and the Utility account for the financial effects of regulation in accordance with SFAS No. 71. SFAS No. 71 applies to regulated entities whose rates are designed to recover the costs of providing service. The Utility is regulated by the CPUC, the FERC and the Nuclear Regulatory

Commission, or the NRC, among others. As discussed further in Note 15, during the first quarter of 2004, the Utility re-adopted SFAS No. 71 for its generation operations. As a result, during the quarter ended March 31, 2004, the Utility recorded a generation regulatory asset of approximately $1.2 billion. SFAS No. 71 now applies to all of the Utility's operations except for the operations of a natural gas pipeline.

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

On a quarterly basis management assesses whether regulatory assets are probable of future recovery through rates by considering factors such as changes in regulation. To the extent that portions of the Utility's operations cease to be subject to SFAS No. 71 or recovery is no longer probable, the related regulatory assets and liabilities are written off.

ACCOUNTING FOR GOODWILL AND OTHER INTANGIBLE ASSETS

PG&E Corporation and the Utility had no goodwill on their Consolidated Balance Sheets at December 31, 2005 or 2004. Other intangible assets consist of an intangible asset relating to the minimum pension liability as discussed below in Note 14 of the Notes to the Consolidated Financial Statements, and hydroelectric facility licenses and other agreements, with lives ranging from 19 to 40 years. The gross carrying amount of the hydroelectric facility licenses and other agreements was approximately $73 million at December 31, 2005 and December 31, 2004. The accumulated amortization was approximately $25 million at December 31, 2005 and $23 million at December 31, 2004.

The Utility's amortization expense related to intangible assets was approximately $3 million in 2005, $4 million in 2004, and $3 million in 2003. The estimated annual amortization expense based on the December 31, 2005 intangible asset balance for the Utility's intangible assets for 2006 through 2010 is approximately $3 million each year. Intangible assets are recorded to Other Noncurrent Assets on the Consolidated Balance Sheets.

INVESTMENTS IN AFFILIATES

The Utility has investments in unconsolidated affiliates, which are mainly engaged in the purchase of low-income residential real estate property. The equity method of accounting is applied to the Utility's investment in these entities. Under the equity method, the Utility's share of equity income or losses of these entities is reflected as equity in earnings of affiliates. As of December 31, 2005, the Utility's recorded investment in these entities totaled approximately $5 million and the Utility has a commitment to make capital infusions of approximately $7 million over the next three years. As a limited partner, the Utility's exposure to potential loss is limited to its investment in each partnership.

CONSOLIDATION OF VARIABLE INTEREST ENTITIES

The Financial Accounting Standards Board, or FASB, Interpretation No. 46 (revised December 2003), "Consolidation of Variable Interest Entities," or FIN 46R, provides that an entity is a variable interest entity, or VIE, if it does not have sufficient equity investment at risk, or if the holders of the entity's equity instruments lack the essential characteristics of a controlling financial interest. FIN 46R requires that the holder subject to a majority of the risk of loss from a VIE's activities must consolidate the VIE. However, if no holder has a majority of the risk of loss, then a holder entitled to receive a majority of the entity's residual returns would consolidate the entity.

Power Purchase Agreements

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

IMPAIRMENT OF LONG-LIVED ASSETS

The carrying values of long-lived assets are evaluated in accordance with the provisions of SFAS No. 144, "Accounting for the Impairment of Long Lived Assets," or SFAS No. 144. In accordance with SFAS No. 144, PG&E Corporation and the Utility evaluate the carrying amounts of long-lived assets for impairment whenever events occur or circumstances change that may affect the recoverability or the estimated life of long-lived assets. SFAS No. 144 became effective at the beginning of 2002 and supersedes SFAS No. 121, "Accounting for the Impairment or Disposal of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of," and the accounting and reporting provisions of Accounting Principles Board Opinion No. 30, "Reporting the Results of Operations for a Disposal of Segment of a Business." SFAS No. 144 did not have a material impact on the consolidated financial position, results of operations or cash flows of PG&E Corporation or the Utility.

FAIR VALUE OF FINANCIAL INSTRUMENTS

The fair value of a financial instrument represents the amount at which the instrument could be exchanged in a current transaction between willing parties, other than in a forced sale or liquidation. Significant differences can occur between the fair value and carrying amount of financial instruments that are recorded at historical amounts.

PG&E Corporation and the Utility use the following methods and assumptions in estimating fair value disclosures for financial instruments:

- The fair values of cash and cash equivalents, restricted cash and deposits, net accounts receivable, price risk management assets and liabilities, short-term borrowings, accounts payable, customer deposits, and the Utility's variable rate pollution control bond loan agreements approximate their carrying values as of December 31, 2005 and 2004;
- The estimated fair values of the Utility's fixed rate Senior Notes, fixed rate pollution control bond loan agreements, rate reduction bonds, energy recovery bonds, or ERBs, and the Utility's preferred stock were based on market prices obtained from the Bloomberg financial information system; and
- The estimated fair value of PG&E Corporation's 9.50% Convertible Subordinated debt was determined by a third party by considering the values embedded in reported trade prices and employing these values in a proprietary option valuation model (using a stock volatility assumption of between 15–20%).

The carrying amount and fair value of PG&E Corporation's and the Utility's financial instruments are as follows (the table below excludes financial instruments with fair values that approximate their carrying values, as these instruments are presented in the Consolidated Balance Sheets):

(in millions)	At December 31,			
	2005		2004	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt (Note 4):				
PG&E Corporation	$ 280	$ 783	$ 280	$ 738
Utility	5,628	5,720	5,632	5,813
Rate reduction bonds (Note 5)	580	591	870	911
Energy recovery bonds (Note 6)	2,592	2,558	–	–
Utility preferred stock with mandatory redemption provisions (Note 9)	–	–	122	127

GAINS AND LOSSES ON DEBT EXTINGUISHMENTS

Gains and losses on debt extinguishments associated with regulated operations that are subject to the provisions of SFAS No. 71 are deferred and amortized over the remaining original amortization period of the debt reacquired, consistent with recovery of costs through regulated rates. Gains and losses on debt extinguishments associated with unregulated operations are fully recognized at the time such debt is reacquired and are reported as a component of interest expense.

ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

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

(in millions)	Hedging Transactions in Accordance with SFAS No. 133	Foreign Currency Translation Adjustment	Minimum Pension Liability Adjustment	Other	Accumulated Other Comprehensive Income (Loss)
Balance at December 31, 2002	$(90)	$(3)	$–	$–	$(93)
Period change in:					
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133	(8)	–	–	–	(8)
Net reclassification to earnings	17	–	–	–	17
Other	–	3	(4)	–	(1)
Balance at December 31, 2003	(81)	–	(4)	–	(85)
Period change in:					
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133	3	–	–	–	3
NEGT losses reclassified to earnings upon elimination of equity interest by PG&E Corporation	77	–	–	–	77
Other	–	–	–	1	1
Balance at December 31, 2004	(1)	–	(4)	1	(4)
Period change in:					
Minimum pension liability adjustment	–	–	(4)	–	(4)
Other	1	–	–	(1)	–
Balance at December 31, 2005	$ –	$–	$(8)	$–	$ (8)

Accumulated other comprehensive income (loss) included losses related to discontinued operations of approximately $77 million at December 31, 2003 and approximately $93 million at December 31, 2002. During the fourth quarter of 2004, the remaining losses of approximately $77 million included in accumulated other comprehensive income (loss) were recognized in connection with PG&E Corporation's elimination of its equity interest in NEGT. Excluding the activity related to NEGT, there was no material difference between PG&E Corporation's and the Utility's accumulated other comprehensive income (loss).

REVENUE RECOGNITION

Electricity revenues, which are comprised of generation, transmission, and distribution services, are billed to the Utility's customers at the CPUC-approved "bundled" electricity rate. Natural gas revenues, which are comprised of transmission and distribution services, are also billed at CPUC-approved rates. In addition, electric transmission

revenues, and both wholesale and retail transmission rates are subject to authorization by the FERC. The Utility's revenues are recognized as natural gas and electricity are delivered, and include amounts for services rendered but not yet billed at the end of each year.

As further discussed in Note 17, in January 2001, the California Department of Water Resources, or DWR, began purchasing electricity to meet the portion of demand of the California investor-owned electric utilities that was not being satisfied from their own generation facilities and existing electricity contracts. Under California law, the DWR is deemed to sell the electricity directly to the Utility's retail customers, not to the Utility. Therefore, the Utility acts as a pass-through entity for electricity purchased by the DWR on behalf of its customers. Although charges for electricity provided by the DWR are included in the amounts the Utility bills its customers, the Utility deducts from its electricity revenues the amounts passed through to the DWR. The pass-through amounts are based on the quantities of electricity provided by the DWR that are consumed by customers at the CPUC-approved remittance rate. These pass-through amounts are excluded from the Utility's electricity revenues in its Consolidated Statements of Income.

STOCK-BASED COMPENSATION

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

The tables below show the effect on net income and earnings per share, or EPS, for PG&E Corporation and the Utility had they elected to account for their stock-based compensation plans using the fair-value method under SFAS No. 123 and using the valuation assumptions disclosed in Note 14, for the years ended December 31, 2005, 2004 and 2003:

	Years ended December 31,		
(in millions, except per share amounts)	2005	2004	2003
Net earnings:			
As reported	$ 917	$4,504	$ 420
Deduct: Incremental stock-based employee compensation expense determined under the fair value based method for all awards, net of related tax effects	(12)	(14)	(19)
Pro forma	$ 905	$4,490	$ 401
Basic earnings per share:			
As reported	$2.40	$10.80	$1.04
Pro forma	2.37	10.77	0.99
Diluted earnings per share:			
As reported	2.37	10.57	1.02
Pro forma	2.33	10.59	0.97

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

	Years ended December 31,		
(in millions)	2005	2004	2003
Net earnings:			
As reported	$918	$3,961	$901
Deduct: Incremental stock-based employee compensation expense determined under the fair value based method for all awards, net of related tax effects	(7)	(8)	(8)
Pro forma	$911	$3,953	$893

EARNINGS PER SHARE

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

and the number of shares assumed purchased, shall be included in weighted average common shares used for the calculation of diluted EPS.

INCOME TAXES

PG&E Corporation and the Utility use the liability method of accounting for income taxes. Income tax expense (benefit) includes current and deferred income taxes resulting from operations during the year. Investment tax credits are amortized over the life of the related property. Other tax credits, mainly synthetic fuel tax credits, are recognized in income as earned.

PG&E Corporation files a consolidated U.S. federal income tax return that includes domestic subsidiaries in which its ownership is 80% or more. In addition, PG&E Corporation files combined state income tax returns where applicable. PG&E Corporation and the Utility are parties to a tax-sharing arrangement under which the Utility determines its income tax provision (benefit) on a stand-alone basis.

Prior to July 8, 2003, the date of NEGT's Chapter 11 filing, PG&E Corporation recognized federal income tax benefits related to the losses of NEGT and its subsidiaries. However, after July 7, 2003, under the cost method of accounting PG&E Corporation has not recognized additional income tax benefits for financial reporting purposes with respect to the losses of NEGT and its subsidiaries. PG&E Corporation was required to continue to include NEGT and its subsidiaries in its consolidated income tax returns covering all periods through October 29, 2004, the effective date of NEGT's plan of reorganization and the cancellation of its equity ownership in NEGT. See Note 11 of the Notes to the Consolidated Financial Statements for further discussion.

ACCOUNTING FOR PRICE RISK MANAGEMENT ACTIVITIES

PG&E Corporation, through the Utility, engages in price risk management activities to manage its exposure to fluctuations in commodity prices and interest rates in its non-trading portfolio. Price risk management activities involve entering into contracts to procure electricity, natural gas, nuclear fuel and firm transmission rights.

PG&E Corporation and the Utility use a variety of derivative instruments such as physical forwards and options, exchange traded futures and options, commodity swaps, firm transmission rights, and other contracts. Derivative instruments are recorded on PG&E Corporation's and the Utility's Consolidated Balance Sheets at fair value. Changes in the fair value of derivative instruments are recorded in earnings, or to the extent they are recoverable through regulated rates, are deferred and recorded in regulatory accounts. Derivative instruments may be designated as cash flow hedges when they are entered into to hedge variable price risk associated with the purchase of commodities. For derivative instruments designated as cash flow hedges, fair value changes are deferred in accumulated other comprehensive income and recognized in earnings as the hedged transactions occur, unless they are recovered in rates, in which case, they are recorded in a regulatory balancing account. Derivative instruments are presented in other current and non-current assets or other current and non-current liabilities unless they meet certain exemptions.

In order for a derivative instrument to be designated as a hedge, the relationship between the hedging instrument and the hedged item or transaction must be highly effective. The effectiveness test is performed at the inception of the hedge and each reporting period thereafter, throughout the period that the hedge is designated. For derivative instruments designated as cash flow hedges associated with non-regulated operations, unrealized gains or losses related to the effective portion of the change in the fair value of the derivative instrument are recorded in accumulated other comprehensive income until the hedged item is recognized in earnings. The ineffective portion of the change in the fair value of the derivative instrument is recognized immediately in earnings. For derivative instruments designated as cash flow hedges associated with the Utility's regulated operations, unrealized gains and losses related to the effective and ineffective portions of the change in the fair value of the derivative instrument to the extent they are recoverable through regulated rates, are deferred and recorded in regulatory accounts.

Hedge accounting is discontinued prospectively if it is determined that the derivative instrument no longer qualifies as an effective hedge, or when the forecasted transaction is no longer probable of occurring. If hedge accounting is discontinued, the derivative instrument continues to be reflected at fair value, with any subsequent changes in fair value recognized immediately in earnings. Gains and losses related to a derivative instrument that were previously recorded in accumulated other comprehensive income will remain there until the hedged item is recognized in earnings, unless the forecasted transaction is probable of not occurring, whereupon the gains and losses from the derivative instrument will be immediately recognized in earnings.

The gains and losses deferred in accumulated other comprehensive income are recognized in earnings when the hedged item matures or is exercised.

Net realized and unrealized gains or losses on derivative instruments are included in various lines on PG&E Corporation's and the Utility's Consolidated Statements of Income, including cost of electricity, cost of natural gas and interest expense. Cash inflows and outflows associated with the settlement of price risk management activities are recognized in operating cash flows on PG&E Corporation's and the Utility's Consolidated Statements of Cash Flows.

The fair value of contracts is estimated using the midpoint of quoted bid and ask forward prices, including quotes from counterparties, brokers, electronic exchanges and published indices, supplemented by online price information from news services. When market data is not available, models are used to estimate fair value.

The Utility has derivative instruments for the physical delivery of commodities transacted in the normal course of business as well as non-financial assets that are not exchange-traded. These derivative instruments are eligible for the normal purchase and sales and non-exchange traded contract exceptions under SFAS No. 133, and are not reflected on the balance sheet at fair value. They are recorded and recognized in income using accrual accounting. Therefore, revenues are recognized as earned and expenses are recognized as incurred.

The Utility has certain commodity contracts for the purchase of nuclear fuel and core gas transportation and storage contracts that are not derivative instruments and are not reflected on the balance sheet at fair value. Revenues are recorded as earned and expenses are recognized as incurred.

NUCLEAR DECOMMISSIONING TRUST INVESTMENT PRESENTATION ON STATEMENT OF CASH FLOWS

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

ADOPTION OF NEW ACCOUNTING PRONOUNCEMENTS

Asset Retirement Obligations

On January 1, 2003, PG&E Corporation and the Utility adopted SFAS No. 143, "Accounting for Asset Retirement Obligations," or SFAS No. 143. The Utility identified its nuclear generation and certain fossil fuel generation facilities as having asset retirement obligations under SFAS No. 143. SFAS No. 143 requires that an asset retirement obligation be recorded at fair value in the period in which it is incurred if a reasonable estimate of fair value can be made. In the same period, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. In each subsequent period, the liability is accreted to its present value and the capitalized cost is depreciated over the useful life of the long-lived asset. Rate-regulated entities may recognize regulatory assets or liabilities as a result of timing differences between the recognition of costs as recorded in accordance with SFAS No. 143 and costs recovered through the ratemaking process. The cumulative effect of the change in accounting principle for the Utility's fossil fuel facilities as a result of adopting SFAS No. 143 was a loss of approximately $1 million, after-tax.

In December 2005, PG&E Corporation and the Utility adopted FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations – an Interpretation of FASB Statement No. 143," or FIN 47. FIN 47 clarifies that if a legal obligation to perform an asset retirement obligation exists but performance is conditional upon a future event, and the obligation can be reasonably estimated, then a liability should be recognized in accordance with SFAS No. 143. The Utility recognized asset retirement obligations of $202 million as a result of adopting FIN 47. The costs associated with asset retirement obligations under FIN 47 are either currently being recovered in rates or are probable of recovery in future rates; therefore, the effects of adopting FIN 47 did not have an impact on earnings.

Upon adoption of FIN 47, the Utility recognized asset retirement obligations related to asbestos contamination in buildings, potential site restoration at certain hydroelectric facilities, fuel storage tanks, and contractual obligations to restore leased property to pre-lease condition. Additionally,

the Utility recognized asset retirement obligations related to the California Gas Transmission pipeline, Gas Distribution, Electric Distribution and Electric Transmission system assets.

The Utility has identified additional asset retirement obligations for which a reasonable estimate of fair value could not be made. The Utility has not recognized a liability related to these additional obligations which include: obligations to restore land to its pre-use condition under the terms of certain land rights agreements, removal and proper disposal of lead-based paint contained in some PG&E facilities, removal of certain communications equipment from leased property and retirement activities associated with substation and certain hydroelectric facilities. The Utility was not able to reasonably estimate the asset retirement obligation associated with these assets because the settlement date of the obligation was indeterminate and information sufficient to reasonably estimate the settlement date or range of settlement dates does not exist. Land rights, communication equipment leases and substation facilities will be maintained for the foreseeable future and the Utility cannot reasonably estimate the settlement date or range of settlement dates for the obligations associated with these assets. The Utility does not have information available that specifies which facilities contain lead-based paint and therefore cannot reasonably estimate the settlement date(s) associated with the obligation. The Utility will maintain and continue to operate its hydroelectric facilities until operation of a facility becomes uneconomic. The operation of the majority of the Utility's hydroelectric facilities is currently economic and the settlement date cannot be determined at this time.

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

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

ACCOUNTING PRONOUNCEMENTS ISSUED BUT NOT YET ADOPTED

Share-Based Payment Transactions

In December 2004, the FASB issued Statement of Financial Accounting Standards, or SFAS, No. 123 (revised December 2004), "Share-Based Payment," or SFAS No. 123R. SFAS No. 123R requires that the cost of all share-based payment transactions be recognized in the financial statements and establishes a fair-value measurement objective in determining the value of such costs. In accordance with SFAS No. 123R, an estimate of forfeitures should be made and compensation expense should be recognized over the requisite service period only for shares that are expected to vest.

PG&E Corporation and the Utility are currently expensing share-based awards, other than stock options, over the stated vesting period regardless of terms that accelerate vesting upon retirement. Upon adoption of SFAS 123R, compensation expense for all awards, including stock options, will be recognized over the shorter of 1) the stated vesting period, or 2) the period from the date of grant through the date the employee is no longer required to provide service to vest.

On April 14, 2005, the Securities and Exchange Commission amended the compliance date and allowed public companies with calendar year-ends to adopt SFAS No. 123R in the first quarter of 2006. The adoption of SFAS No. 123R is not expected to have a material impact on the Consolidated Financial Statements.

Accounting Changes and Error Corrections

In May 2005, the FASB issued FASB Statement No. 154, "Accounting Changes and Error Corrections Disclosure," or SFAS No. 154. SFAS No. 154 replaces Accounting Principles Board, or APB, Opinion No. 20, "Accounting Changes," or APB No. 20, and FASB Statement No. 3, "Reporting Accounting Changes in Interim Financial Statements," or SFAS No. 3. SFAS No. 154 requires retrospective application to prior periods' financial statements of changes in accounting principle unless it is impracticable. This Statement applies to all voluntary changes in accounting principle. SFAS No. 154 is effective for the first quarter of 2006.

Other-Than-Temporary Impairment

In November 2005, the FASB issued Staff Position Nos. FAS 115-1 and 124-1, "The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments," or FSP 115-1 and 124-1. This FASB Staff Position provides guidance in determining when an investment is impaired; whether that impairment is other-than-temporary; and the measurement of an impairment loss. Guidance is applicable to reporting periods beginning January 1, 2006. The adoption of FSP 115-1 and 124-1 is not expected to have a material impact on the Consolidated Financial Statements.

Changes in Accounting for Certain Derivative Contracts

Derivatives Implementation Group, or DIG, Issue No. B38, "Embedded Derivatives: Evaluation of Net Settlement with respect to the Settlement of a Debt Instrument through Exercise of an Embedded Put Option or Call Option," or DIG B38, and DIG Issue No. B39 "Embedded Derivatives: Application of Paragraph 13(b) to Call Options That Are Exercisable Only by the Debtor," or DIG B39, address the circumstances in which a put or call option embedded in a debt instrument would be bifurcated from the debt instrument and accounted for separately. DIG B38 and DIG B39 are effective in the first quarter of 2006. PG&E Corporation and the Utility have evaluated the accounting guidance contained in DIG B38 and DIG B39 and have determined that the guidance does not alter the accounting for debt instruments issued or held by PG&E Corporation and the Utility.

NOTE 3: REGULATORY ASSETS, LIABILITIES AND BALANCING ACCOUNTS

REGULATORY ASSETS

Regulatory assets are comprised of the following:

	Balance at December 31,	
(in millions)	2005	2004
Settlement regulatory asset	$ –	$3,188
Energy recovery bond regulatory asset	2,509	–
Utility retained generation regulatory assets	1,099	1,181
Rate reduction bond assets	456	741
Regulatory assets for deferred income tax	536	490
Unamortized loss, net of gain, on reacquired debt	321	345
Environmental compliance costs	310	192
Post-transition period contract termination costs	131	142
Regulatory assets associated with plan of reorganization	163	182
Other, net	53	65
Total regulatory assets	$5,578	$6,526

In light of the satisfaction of various conditions to the implementation of the plan of reorganization, the accounting probability standard required to be met under SFAS No. 71 in order for the Utility to recognize the regulatory assets provided under the Settlement Agreement (as described in Note 15) was met as of March 31, 2004. Therefore, the Utility recorded the $3.7 billion, pre-tax ($2.2 billion, after-tax), regulatory asset established under the Settlement Agreement, or the Settlement Regulatory Asset, and $1.2 billion, pre-tax ($0.7 billion, after-tax), for the Utility retained generation regulatory assets in the first quarter of 2004 (see Note 15 for further discussion). As of December 31, 2005, the remaining balance of the Settlement Regulatory Asset was reduced

by the issuance of the first and second series of ERBs and supplier refunds (see below for further discussion). The Utility also recorded amortization of the Settlement Regulatory Asset of approximately $145 million and amortization of the Utility retained generation regulatory assets of approximately $82 million during the year ended December 31, 2005.

On February 10, 2005, PG&E Energy Recovery Funding, LLC, or PERF, a limited liability company wholly owned and consolidated by the Utility (but legally separate from the Utility), issued the first series of ERBs for approximately $1.9 billion to refinance the after-tax balance of the Settlement Regulatory Asset. As a result of the issuance of the first series of ERBs, the pre-tax Settlement Regulatory Asset was reduced to approximately $1.3 billion (representing the deferred tax liability associated with the collection of the revenues for the ERBs) and the Utility recorded an energy recovery bond regulatory asset of approximately $1.9 billion.

On November 9, 2005, PERF issued the second series of ERBs for approximately $844 million to pre-fund the Utility's tax liability that will be due as the Utility collects the dedicated rate component, or DRC, related to the first series of ERBs. As a result of the second issuance, the remaining Settlement Regulatory Asset was fully refinanced and the Utility recorded an additional energy recovery bond regulatory asset for $838 million. The energy supplier refunds that the Utility received between the issuance of the first and second series of ERBs of approximately $330 million were used to reduce the size of the second series of ERBs. During the year ended December 31, 2005 the Utility recorded amortization of the energy recovery bond regulatory asset of approximately $202 million and expects to fully recover this asset by the end of 2012.

The Utility's regulatory asset related to the rate reduction bonds, or RRBs, represents electric industry restructuring costs that the Utility expects to collect over the term of the RRBs. The Utility recorded amortization of the RRB regulatory asset of approximately $285 million during the year ended December 31, 2005 and expects to fully recover this asset by the end of 2007. The regulatory assets for deferred income tax represent deferred income tax benefits that have already been passed through to customers and are offset by deferred income tax liabilities. Tax benefits to customers have been passed through as the CPUC requires utilities under its jurisdiction to follow the "flow through" method of passing benefits to customers. The "flow through" method ignores the effect of deferred taxes on rates. Based on current regulatory ratemaking and income tax laws, the Utility expects to recover deferred income tax-related regulatory assets over periods ranging from 1 to 40 years. The regulatory asset related to unamortized loss, net of gain, on reacquired debt represents costs on debt reacquired or redeemed prior to maturity with associated discount and debt issuance costs. These costs are expected to be recovered over the remaining original amortization period of the reacquired debt over the next 1 to 21 years. Environmental compliance costs are costs incurred by the Utility for environmental remediation. During the year ended December 31, 2005 the Utility recorded an additional regulatory asset of approximately $118 million mainly due to reassessment of the estimated cost of remediation. This amount is expected to be recovered in the future rates as remediation costs are incurred. The post-transition period contract termination costs represent amounts the Utility incurred in terminating a 30-year power purchase agreement. This regulatory asset will be amortized and collected in rates on a straight-line basis until the end of September 2014, the power purchase agreement's original termination date. Regulatory assets associated with the plan of reorganization include costs incurred in financing the Utility's exit from Chapter 11 and costs to oversee the environmental enhancement of the Pacific Forest and Watershed Stewardship Council, an entity that was established pursuant to the Utility's plan of reorganization. The Utility expects to recover these costs over periods ranging from 2 to 30 years.

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

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

REGULATORY LIABILITIES

Regulatory liabilities are comprised of the following:

	Balance at December 31,	
(in millions)	2005	2004
Cost of removal obligation	$2,141	$1,990
Asset retirement costs	538	700
Employee benefit plans	195	687
Price risk management	213	–
Public purpose programs	154	191
Rate reduction bonds	157	182
Other	108	285
Total regulatory liabilities	$3,506	$4,035

The Utility's regulatory liabilities related to cost of removal represent revenues collected for asset removal costs that the Utility expects to incur in the future. The regulatory liability associated with asset retirement costs represents timing differences between the recognition of asset retirement obligations in accordance with GAAP applicable to non-regulated entities under SFAS No. 143 and FIN 47 and the amounts recognized for ratemaking purposes. The Utility's regulatory liabilities related to employee benefit plan expenses represent the cumulative differences between expenses recognized for financial accounting purposes and expenses recognized for ratemaking purposes. These balances will be charged against expense to the extent that future financial accounting expenses exceed amounts recoverable for regulatory purposes. The Utility's regulatory liability related to price risk management represents contracts entered into by the Utility to procure electricity, natural gas and nuclear fuel which are accounted for as derivatives under SFAS No. 133. Additionally, the Utility hedges natural gas in the electric and natural gas portfolios on behalf of its customers to reduce commodity price risk. The costs and proceeds of these derivatives are recovered in regulated rates charged to customers. The Utility's regulatory liability related to public purpose programs represents revenues designated for public purpose program costs that are expected to be incurred in the future. The Utility's regulatory liability for rate reduction bonds represents the deferral of over-collected revenue associated with the rate reduction bonds that the Utility expects to return to customers in the future.

REGULATORY BALANCING ACCOUNTS

The Utility's regulatory balancing accounts are used as a mechanism for the Utility to recover amounts incurred for certain costs, primarily commodity costs. Sales balancing accounts accumulate differences between revenues and the Utility's authorized revenue requirements. Cost balancing accounts accumulate differences between incurred costs and authorized revenue requirements. The Utility also obtained CPUC approval for balancing account treatment of variances between forecasted and actual commodity costs and volumes. This approval results in eliminating the earnings impact from any throughput and revenue variances from adopted forecast levels. Under-collections that are probable of recovery through regulated rates are recorded as regulatory balancing account assets. Over-collections that are probable of being credited to customers are recorded as regulatory balancing account liabilities. The Utility's regulatory balancing accounts accumulate balances until they are refunded to or received from the Utility's customers through authorized rate adjustments within the next twelve months. Regulatory balancing accounts that the Utility does not expect to collect or refund in the next twelve months are included in non-current regulatory assets and liabilities.

During the California energy crisis, the Utility could not conclude that power generation and procurement-related balancing accounts met the probability requirements of SFAS No. 71. However, the Utility was able to continue to record balancing accounts associated with its electricity transmission and distribution and natural gas transportation businesses.

Regulatory Balancing Account Assets

	Balance at December 31,	
(in millions)	2005	2004
Natural gas revenue and cost balancing accounts	$159	$ 171
Electricity revenue and cost balancing accounts	568	850
Total	$727	$1,021

Regulatory Balancing Account Liabilities

(in millions)	Balance at December 31, 2005	2004
Natural gas revenue and cost balancing accounts	$ 13	$ 34
Electricity revenue and cost balancing accounts	827	335
Total	$840	$369

The CPUC does not allow the Utility to offset regulatory balancing account assets against balancing account liabilities. During 2005, the annual true-up proceedings provided the Utility with a mechanism to better recover under-collections and refund over-collections from the prior year and to recover current year forecasts over the next twelve months. The decrease in the Utility's under-collected position from 2004 is primarily due to increased revenue requirements in 2005 to recover under-collections from 2004 combined with a decrease in usage in 2005 as compared to 2004, resulting in a reduction of costs passed through to customers. In addition, the Utility entered into settlements with various power suppliers (see further discussion in Note 17) during 2005. The Utility passes the majority of the benefit of these settlements on to its customers.

NOTE 4: DEBT

LONG-TERM DEBT

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

(in millions)	December 31, 2005	2004
PG&E Corporation		
Convertible subordinated notes, 9.50%, due 2010	$ 280	$ 280
Other long-term debt	—	1
Less: current portion	—	(1)
	280	280
Utility		
Senior notes/first mortgage bonds[1]:		
3.60% to 6.05% bonds, due 2009–2034	5,100	6,200
Unamortized discount, net of premium	(17)	(17)
Total senior notes/first mortgage bonds	5,083	6,183
Pollution control bond loan agreements, variable rates[2], due 2026[3]	614	614
Pollution control bond loan agreement, 5.35%, due 2016	200	200
Pollution control bond loan agreements, 3.50%, due 2023[4]	345	345
Pollution control bond loan agreements, variable rates[5], due 2016–2026	454	—
Pollution control bond reimbursement agreements, variable rates, due 2005	—	454
Other	2	4
Less: current portion	(2)	(757)
	6,696	7,043
Total consolidated long-term debt, net of current portion	$6,976	$7,323

(1) When originally issued, these debt instruments were denominated as first mortgage bonds and were secured by a lien, subject to permitted exceptions, on substantially all of the Utility's real property and certain tangible personal property related to its facilities. The indenture under which the first mortgage bonds were issued provided for release of the lien in certain circumstances subject to certain conditions. The release occurred in April 2005 and the remaining bonds were redesignated as senior notes.

(2) At December 31, 2005, interest rates on these loans ranged from 3.70% to 3.79%.

(3) These bonds are supported by $620 million of letters of credit which expire on April 22, 2010. Although the stated maturity date is 2026, the bonds will remain outstanding only if the Utility extends or replaces the letters of credit.

(4) These bonds are subject to a mandatory tender for purchase on June 1, 2007 and the interest rates for these bonds are set until that date.

(5) At December 31, 2005, interest rates on these loans ranged from 3.10% to 3.35%.

PG&E Corporation

Convertible Subordinated Notes

As of December 31, 2005, PG&E Corporation has outstanding $280 million of 9.50% Convertible Subordinated Notes that are scheduled to mature on June 30, 2010, or Convertible Subordinated Notes. These Convertible Subordinated Notes may be converted (at the option of the holder) at any time prior to maturity into 18,558,655 shares of common stock of PG&E Corporation, at a conversion price of approximately $15.09 per share. The conversion price is subject to adjustment should a significant change occur in the number of PG&E Corporation's outstanding common shares. To date, the conversion price has not required adjustment. In addition, holders of the Convertible Subordinated Notes are entitled to receive "pass-through dividends" at the same payout as common stockholders with the number of shares determined by dividing the principal amount of the Convertible Subordinated Notes by the conversion price. In connection with each common stock dividend that was paid to holders of PG&E Corporation common stock on April 15, July 15 and October 17, 2005, and January 17, 2006, PG&E Corporation paid approximately $6 million of "pass-through dividends" to the holders of Convertible Subordinated Notes. The holders have a one-time right to require PG&E Corporation to repurchase the Convertible Subordinated Notes on June 30, 2007, at a purchase price equal to the principal amount plus accrued and unpaid interest (including liquidated damages and unpaid "pass-through dividends," if any).

In accordance with SFAS No. 133, the dividend participation rights component is considered to be an embedded derivative instrument and, therefore, must be bifurcated from the Convertible Subordinated Notes and recorded at fair value in PG&E Corporation's Consolidated Financial Statements. Changes in the fair value are recognized in PG&E Corporation's Consolidated Statements of Income as a non-operating expense or income (included in Other income (expense), net). At December 31, 2005 and 2004, the total estimated fair value of the dividend participation rights component, on a pre-tax basis, was approximately $92 million and $91 million, respectively, of which $22 million and $15 million, respectively, is classified as a current liability (in Current liabilities – Other) and $70 million and $76 million, respectively, is classified as a noncurrent liability (in Noncurrent liabilities – Other). The liability, which was initially recorded in 2004, did not change by a material amount during 2005.

UTILITY

First Mortgage Bonds/Senior Notes

On March 23, 2004, the Utility closed a public offering of $6.7 billion of first mortgage bonds, or First Mortgage Bonds. The First Mortgage Bonds were offered in multiple tranches consisting of 3.60% First Mortgage Bonds due March 1, 2009 in the principal amount of $600 million, 4.20% First Mortgage Bonds due March 1, 2011 in the principal amount of $500 million, 4.80% First Mortgage Bonds due March 1, 2014 in the principal amount of $1 billion, 6.05% First Mortgage Bonds due March 1, 2034 in the principal amount of $3 billion, and Floating Rate First Mortgage Bonds due April 3, 2006 in the principal amount of $1.6 billion. The Utility received proceeds of $6.7 billion from the offering, net of a discount of $18 million. First Mortgage Bonds in the aggregate amount of $2.5 billion also were used to secure the Utility's obligations under various other debt agreements. On October 3, 2004, the Utility redeemed Floating Rate First Mortgage Bonds due in 2006 in the aggregate principal amount of $500 million. On January 3, 2005, in anticipation of the receipt of the ERB proceeds, the Utility partially redeemed Floating Rate First Mortgage Bonds due in 2006 in the aggregate principal amount of $300 million. On February 24, 2005, the Utility used a portion of the ERB proceeds to defease $600 million of Floating Rate First Mortgage Bonds due in 2006. The defeased bonds were redeemed on April 3, 2005. On July 3, 2005, the remaining $200 million of Floating Rate Senior Notes (as redesignated) were redeemed.

The First Mortgage Bonds were secured by a first lien, subject to permitted exceptions, on substantially all of the Utility's real property and certain tangible personal property related to the Utility's facilities. The lien was released on April 22, 2005, upon satisfaction of various conditions specified in the indenture and the First Mortgage Bonds that had not been redeemed were redesignated as Senior Notes. The maturity dates and interest rates remained unchanged.

The Senior Notes are unsecured general obligations ranking equal with the Utility's other senior unsecured debt. Under the indenture for the Senior Notes, the Utility has agreed that it will not incur secured debt (except for (1) debt secured by specified liens, and (2) secured debt in an amount not exceeding 10% of the Utility's net tangible assets, as defined in the indenture) unless the Utility provides that the Senior Notes will be equally and ratably secured with the new secured debt.

At December 31, 2005, there were $5.1 billion of Senior Notes outstanding.

Pollution Control Bonds

The California Pollution Control Financing Authority, or CPCFA, and the California Infrastructure & Economic Development Bank, or CIEDB, issued various series of tax-exempt pollution control bonds for the benefit of the Utility. At December 31, 2005, there were $1.6 billion principal amount of these pollution control bonds outstanding. Under the pollution control bond loan agreements, the Utility is obligated to pay on the due dates an amount equal to the principal, premium, if any, and interest on these bonds to the trustees for these bonds.

The majority of the pollution control bonds financed or refinanced pollution control facilities at the Utility's Geysers geothermal power plant, or the Geysers Project, or at the Utility's Diablo Canyon nuclear power plant, or Diablo Canyon. In 1999, the Utility sold the Geysers Project to Geysers Power Company LLC, a subsidiary of Calpine Corporation. The Geysers Project purchase and sale agreements state that Geysers Power Company LLC will use the facilities solely as pollution control facilities within the meaning of Section 103(b)(4)(F) of the Internal Revenue Code and associated regulations, or the Code. On February 3, 2006, Geysers Power Company LLC filed for reorganization under Chapter 11 of the U.S. Bankruptcy Code. If Geysers Power Company LLC, or a successor-in-interest to the Geysers Project, fails to use the facilities as pollution control facilities within the meaning of Section 103(b)(4)(F) of the Code, the pollution control bonds could lose their tax-exempt status.

In order to enhance the credit ratings of these pollution control bonds, the Utility has obtained credit support from banks and insurance companies. These third parties have reimbursement agreements covering the terms of the Utility's debt service repayment amounts. This additional layer of credit support gives bondholders reassurance that, in the event that the Utility does not pay debt servicing costs, the banks or insurance companies will pay the debt servicing costs, which is represented in the following table:

(in millions)

Utility Facility[1]	Series	Termination Date	At December 31, 2005 Commitment	Outstanding
Pollution control bond bank reimbursement agreements	96 C, E, F, 97 B	April 2010	$ 620	$ 620
Pollution control bond – bond insurance reimbursement agreements	96A	December 2016[2]	200	200
Pollution control bond – bond insurance reimbursement agreements	2004 A–D	December 2023[2]	345	345
Pollution control bond – bond insurance reimbursement agreements	2005 A–G	2016–2026[2]	454	454
Total credit support			$1,619	$1,619

(1) Off-balance sheet commitments.

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

On April 20, 2005, the Utility repaid $454 million under pollution control bond loan agreements that the Utility had entered into in April 2004. The repayment of these reimbursement agreements was made through $454 million of borrowings under the Utility's working capital facility (see further discussion of the working capital facility below). Subsequently, on May 24, 2005, the Utility entered into seven loan agreements with the CIEDB to issue seven series of tax-exempt pollution control bonds, or PC Bonds Series A-G, totaling $454 million. These series are in auction modes where interest rates are set among investors who submit bids to buy, sell, or hold securities at desired rates. Four series of the bonds (Series A-D) have auctions every 35 days and three series (Series E-G) have auctions every seven days. Maturities on the bonds range from 2016 to 2026. The Utility repaid borrowings under the working capital facility using the proceeds from the tax-exempt PC Bonds Series A-G.

On April 22, 2005, the Utility entered into an amendment to four bank reimbursement agreements totaling $620 million related to letters of credit that had been issued to support certain pollution control bond loan agreements aggregating $614 million issued by the CPCFA on behalf of the Utility. In addition to reducing pricing and generally conforming the covenants and events of default to those in the working capital facility (described below), the terms of the amended reimbursement agreements have been extended until April 22, 2010.

Repayment Schedule

At December 31, 2005, PG&E Corporation's and the Utility's combined aggregate principal repayment amounts of long-term debt, rate reduction bonds, and ERBs are reflected in the table below:

(in millions)	2006	2007	2008	2009	2010	Thereafter	Total
Long-term debt:							
PG&E Corporation							
Average fixed interest rate	–	–	–	–	9.50%	–	9.50%
Fixed rate obligations	$ –	$ –	$ –	$ –	$ 280	$ –	$ 280
Utility							
Average fixed interest rate	–	3.50%	–	3.60%	–	5.56%	5.22%
Fixed rate obligations	$ –	$ 345[1]	$ –	$ 600	$ –	$4,683	$5,628
Variable interest rate as of December 31, 2005	–	–	–	–	3.73%	3.20%	3.51%
Variable rate obligations	$ –	$ –	$ –	$ –	$ 614[2]	$ 454	$1,068
Other	$ 2	$ –	$ –	$ –	$ –	$ –	$ 2
Total consolidated long-term debt	$ 2	$ 345	$ –	$ 600	$ 894	$5,137	$6,978

(1) The $345 million pollution control bonds, due in 2023, are subject to a mandatory tender for purchase on June 1, 2007. Under the loan agreement, unless the Utility remarkets the bonds by June 1, 2007, the bonds will either be returned to the bondholders and bear interest at a daily rate equal to 10% or the Utility has the option to redeem the bonds. Accordingly, these bonds are classified for repayment purposes in 2007.

(2) The $614 million pollution control bonds, due in 2026, are backed by letters of credit which expire on April 22, 2010. The Utility will be subject to a mandatory redemption unless the letters of credit are extended or replaced. Accordingly, the bonds have been classified for repayment purposes in 2010.

ENERGY RECOVERY BONDS & RATE REDUCTION BONDS:

(in millions)	2006	2007	2008	2009	2010	Thereafter	Total
Utility							
Average fixed interest rate	6.44%	6.48%	–	–	–	–	6.46%
Rate reduction bonds	$ 290	$ 290	$ –	$ –	$ –	$ –	$ 580
Average fixed interest rate	3.94%	4.19%	4.19%	4.36%	4.49%	4.63%	4.37%
Energy recovery bonds	$ 316	$ 340	$ 354	$ 369	$ 386	$ 827	$2,592

CREDIT FACILITIES AND SHORT-TERM BORROWINGS

The following table summarizes PG&E Corporation's and the Utility's short-term borrowings and outstanding credit facilities at December 31, 2005:

(in millions)			At December 31, 2005			
Authorized Borrower	Facility	Termination Date	Facility Limit	Letters of Credit Outstanding	Cash Borrowings	Availability
PG&E Corporation	Senior credit facility	December 2009	$ 200[1]	$ –	$ –	$ 200
Utility	Accounts receivable financing	March 2007	650	–	260	390
Utility	Working capital facility	April 2010	1,350[2]	242	–	1,108
Total credit facilities			$2,200	$242	$260	$1,698

(1) Includes $50 million sublimit for Letters of Credit and $100 million sublimit for swingline loans, which are made available on a same-day basis and repayable in full within thirty days.

(2) Includes a $950 million sublimit for Letters of Credit and $100 million sublimit for swingline loans, which are made available on a same-day basis and repayable in full within thirty days.

PG&E CORPORATION

Senior Credit Facility

On December 10, 2004, PG&E Corporation entered into a $200 million three-year revolving senior unsecured credit facility, or senior credit facility, with a syndicate of lenders. The aggregate facility of $200 million includes a $50 million sublimit for the issuance of letters of credit and a $100 million sublimit for swingline loans. Borrowings under the senior credit facility and letters of credit may be used primarily for working capital and other corporate purposes. On April 8, 2005, PG&E Corporation entered into an amendment, which became effective on April 12, 2005, to the $200 million revolving senior unsecured credit facility, or the senior credit facility, to extend its term from three years to five years, with all amounts due and payable on December 10, 2009. In addition, the amendment made other changes to the senior credit facility to conform the covenants, representations and events of default to those in the Utility's working capital facility, discussed below. PG&E Corporation can, at any time, repay amounts outstanding in whole or in part. At PG&E Corporation's request and at the sole discretion of each lender, the senior credit facility may be extended for additional periods. PG&E Corporation has the right to increase, in one or more requests given no more than once a year, the aggregate facility by up to $100 million provided certain conditions are met. At December 31, 2005, PG&E Corporation had not undertaken any borrowings or issued any letters of credit under the senior credit facility.

The fees and interest rates PG&E Corporation pays under the senior credit facility vary depending on the Utility's unsecured debt ratings issued by Standard & Poor's Ratings Service, or S&P, and Moody's Investors Service, or Moody's. Interest is payable quarterly in arrears, or earlier for loans with shorter interest periods. In addition, a facility fee based on the aggregate facility and a utilization fee based on the average daily amount outstanding under the senior credit facility are payable by PG&E Corporation quarterly in arrears.

In addition, PG&E Corporation pays a fee for each letter of credit outstanding under the senior credit facility and a fronting fee of 0.125% to the issuer of a letter of credit. Interest, fronting fees, and normal lender costs of issuing and negotiating letter of credit arrangements are payable quarterly in arrears.

The senior credit facility includes usual and customary covenants for credit facilities of this type, including covenants limiting liens, mergers, sales of all or substantially all of PG&E Corporation's assets and other fundamental changes. The senior credit facility also requires that PG&E Corporation maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% and that PG&E Corporation own, directly or indirectly, at least 80% of the common stock and at least 70% of the voting securities of the Utility.

UTILITY

Accounts Receivable Financing

On March 5, 2004, the Utility entered into certain agreements providing for the continuous sale of a portion of the Utility's accounts receivable to PG&E Accounts Receivable Company, LLC, or PG&E ARC, a limited liability company wholly owned by the Utility. In turn, PG&E ARC sells interests in its accounts receivable to commercial paper conduits or banks. PG&E ARC may obtain up to $650 million of financing under such agreements. The borrowings under this facility bear interest at commercial paper rates and a fixed margin based on the Utility's credit ratings. Interest on the facility is payable monthly. At December 31, 2005, the average interest rate on borrowings on the accounts receivable facility was 4.34%. The maximum amount available for borrowing under this facility changes based upon the amount of eligible receivables, concentration of eligible receivables and other factors. The accounts receivable facility will terminate on March 5, 2007. There were $260 million of borrowings outstanding under the accounts receivable facility at December 31, 2005 and no borrowings outstanding at December 31, 2004.

Although PG&E ARC is a wholly owned consolidated subsidiary of the Utility, PG&E ARC is legally separate from the Utility. The assets of PG&E ARC (including the accounts receivable) are not available to creditors of the Utility or PG&E Corporation, and the accounts receivable are not legally assets of the Utility or PG&E Corporation. For the purposes of financial reporting, the credit facility is accounted for as a secured financing.

The accounts receivable facility includes a covenant from the Utility requiring it to maintain, as of the end of each fiscal quarter ending after the effective date of the Utility's plan of reorganization, a debt to capitalization ratio of at most 65%.

Working Capital Facility

On April 8, 2005, the Utility entered into a $1 billion revolving credit facility, or the working capital facility. This credit facility replaced the $850 million credit facility that the Utility entered into on March 5, 2004 that included a $600 million sublimit for the issuance of letters of credit and a $100 million sublimit for swingline loans. On November 30, 2005, the Utility entered into an amendment to the working capital facility. The amendment increases the amount of the revolving working capital facility by $350 million to a total of $1.35 billion and the $600 million sublimit for letters of credit to $950 million. The sublimit for swingline loans remain the same.

Loans under the working capital facility will be used primarily to cover operating expenses and seasonal fluctuations in cash flows and were used for bridge financing in connection with the repayment of the pollution control bond loan agreements discussed above. Letters of credit under the working capital facility will be used primarily to provide credit enhancements to counterparties for natural gas and energy procurement transactions.

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

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

The fees and interest rates the Utility pays under the working capital facility vary depending on the Utility's unsecured debt rating by S&P and Moody's. The Utility is also required to pay a facility fee based on the total amount of working capital facility (regardless of the usage) and a utilization fee based on the average daily amount outstanding under the working capital facility. Interest is payable quarterly in arrears, or earlier for loans with shorter interest periods.

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

At December 31, 2005, there were no loans outstanding and approximately $242 million of letters of credit outstanding under the $1.35 billion working capital facility.

Commercial Paper Program

On January 10, 2006, the Utility entered into various agreements to establish the terms and procedures for the issuance of up to $1 billion of unsecured commercial paper by the Utility for general corporate purposes. The notes will not be registered under the Securities Act of 1933 or applicable state securities laws and may not be offered or sold in the United States absent registration under the Securities Act of 1933 or applicable state exemption from registration requirements. The commercial paper may have maturities up to 365 days and will rank equally with the Utility's unsubordinated and unsecured indebtedness.

NOTE 5: RATE REDUCTION BONDS

In December 1997, PG&E Funding, LLC, a limited liability corporation wholly owned by and consolidated by the Utility, issued $2.9 billion of rate reduction bonds. The proceeds of the rate reduction bonds were used by PG&E Funding, LLC to purchase from the Utility the right, known as "transition property," to be paid a specified amount from a non-bypassable charge levied on residential and small commercial customers (Fixed Transition Amount, or FTA,

charges). FTA charges are authorized by the CPUC under state legislation and will be paid by residential and small commercial customers until the rate reduction bonds are fully retired. Under the terms of a transition property servicing agreement, FTA charges are collected by the Utility and remitted to PG&E Funding, LLC for the payment of the bond principal, interest and miscellaneous expenses associated with the bonds.

The total amount of rate reduction bonds principal outstanding was $580 million at December 31, 2005 and $870 million at December 31, 2004. The scheduled principal payments on the rate reduction bonds for the years 2006 through 2007 are $290 million for each year. The rate reduction bonds have expected maturity dates of 2006 and 2007, and bear interest at rates ranging from 6.42% to 6.48%.

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

NOTE 6: ENERGY RECOVERY BONDS

In connection with the Settlement Agreement, PG&E Corporation and the Utility agreed to seek to refinance the unamortized portion of the Settlement Regulatory Asset and associated federal and state income and franchise taxes, in an aggregate principal amount of up to $3.0 billion in two separate series up to one year apart, using a securitized financing supported by a dedicated rate component, or DRC. PERF issued two separate series of ERBs in the aggregate amount of $2.7 billion. The proceeds of the ERBs were used by PERF to purchase from the Utility the right, known as "recovery property," to be paid a specified amount from a DRC. DRC charges are authorized by the CPUC under state legislation and will be paid by the Utility's electricity customers until the ERBs are fully retired. Under the terms of a recovery property servicing agreement, DRC charges are collected by the Utility and remitted to PERF for payment of the bond principal, interest and miscellaneous expenses associated with the bonds.

The aggregate principal amount of the first series of ERBs issued on February 10, 2005 was approximately $1.9 billion. They were issued in five classes, with scheduled maturities ranging from September 25, 2006 to December 25, 2012. Interest rates on the five classes range from 3.32% for the earliest maturing class to 4.47% for the latest maturing class. The proceeds of the first series of ERBs were paid by PERF to the Utility and were used by the Utility to refinance the remaining unamortized after-tax balance of the Settlement Regulatory Asset. On November 9, 2005, PERF issued the second series of ERBs. The aggregate principal amount of the second series was approximately $844 million. The second series was issued in three classes, with scheduled maturities ranging from June 25, 2009 to December 25, 2012. Interest rates on the three classes range from 4.85% for the earliest maturing class to 5.12% for the latest maturing class. The proceeds of the second series of ERBs were paid by PERF to the Utility to pre-fund the Utility's tax liability that will be due as the Utility collects the DRC related to the first series of ERBs.

At December 31, 2005, the total principal amount of ERBs outstanding was $2.6 billion. The scheduled principal payments on the ERBs for the years 2006 through 2010 are $316 million, $340 million, $354 million, $369 million, and $386 million, respectively. The remaining payments thereafter total $827 million.

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

NOTE 7: DISCONTINUED OPERATIONS

Effective July 8, 2003, which is the date NEGT filed a voluntary petition for relief under Chapter 11, NEGT and its subsidiaries were no longer consolidated by PG&E Corporation in its Consolidated Financial Statements. Under GAAP, consolidation is generally required for entities owning more than 50% of the outstanding voting stock of an investee, except when control is not held by the majority owner. Legal reorganization and bankruptcy represent conditions that can preclude consolidation in instances where control rests with an entity other than the majority owner. In anticipation of NEGT's Chapter 11 filing, PG&E Corporation's representatives who previously served on the NEGT Board of Directors resigned on July 7, 2003, and were replaced with Board members who were not affiliated with PG&E Corporation. As a result, PG&E Corporation no longer retained significant influence over the ongoing operations of NEGT.

Accordingly, at December 31, 2003, PG&E Corporation's net negative investment in NEGT of approximately $1.2 billion was reflected as a single amount, under the cost method, within the December 31, 2003 Consolidated Balance Sheet of PG&E Corporation. This negative investment represents the losses of NEGT recognized by PG&E Corporation in excess of its investment in and advances to NEGT.

On October 29, 2004, NEGT's plan of reorganization became effective, at which time NEGT emerged from Chapter 11 and PG&E Corporation's equity ownership in NEGT was cancelled. On the effective date, PG&E Corporation reversed its negative investment in NEGT and also reversed net deferred income tax assets of approximately $428 million and a charge of approximately $120 million ($77 million, after tax) in accumulated other comprehensive income, related to NEGT. The resulting net gain has been offset by the $30 million payment made by PG&E Corporation to NEGT pursuant to the parties' settlement of certain tax-related litigation and other adjustments to NEGT-related liabilities. A summary of the effect on the quarter and year ended December 31, 2004 earnings from discontinued operations is as follows:

(in millions)	
Investment in NEGT	$1,208
Accumulated other comprehensive income	(120)
Cash paid pursuant to settlement of tax related litigation	(30)
Tax effect	(374)
Gain on disposal of NEGT, net of tax	$ 684

At December 31, 2004, PG&E Corporation's Consolidated Balance Sheet includes approximately $138 million in income tax liabilities (including $86 million in current income taxes payable) and approximately $25 million of other net liabilities related to NEGT. At December 31, 2005, PG&E Corporation's Consolidated Balance Sheet includes approximately $89 million of current income taxes payable and approximately $24 million of other net liabilities related to NEGT. Until PG&E Corporation reaches final settlement of these obligations, it will continue to disclose fluctuations in these estimated liabilities in discontinued operations. Beginning on the effective date of NEGT's plan of reorganization, PG&E Corporation no longer includes NEGT or its subsidiaries in its consolidated income tax returns.

During the third quarter of 2005, PG&E Corporation received additional information from NEGT regarding income to be included in PG&E Corporation's 2004 federal income tax return. This information was incorporated in the 2004 tax return, which was filed with the Internal Revenue Service, or IRS, in September 2005. As a result, the 2004 federal income tax liability was reduced by approximately $19 million. In addition, NEGT provided additional information with respect to amounts previously included in PG&E Corporation's 2003 federal income tax return. This change resulted in PG&E Corporation's 2003 federal income tax liability increasing by approximately $6 million. These two adjustments, netting to $13 million, were recognized in income from discontinued operations in the third quarter of 2005.

NOTE 8: COMMON STOCK

PG&E CORPORATION

PG&E Corporation has authorized 800 million shares of no-par common stock of which 368,268,502 shares were issued and outstanding at December 31, 2005 and 418,616,141 were issued and outstanding at December 31, 2004. A wholly owned subsidiary of PG&E Corporation, Elm Power Corporation holds, 24,665,500 of the outstanding shares.

Of the 368,268,502 shares issued and outstanding at December 31, 2005, 1,399,990 shares have been granted as restricted stock under the PG&E Corporation Long-Term Incentive Program, or LTIP. Further, PG&E Corporation issues common stock in connection with employee benefit plans. See Note 14 for further discussion.

In 2002, PG&E Corporation issued warrants to purchase 5,066,931 shares of its common stock at an exercise price of $0.01 per share. During 2005, 295,919 shares of PG&E Corporation common stock were issued upon the exercise of the warrants. At December 31, 2005, 51,904 of these warrants were outstanding and exercisable. The warrants expire September 2, 2006.

Stock Repurchases

During the fourth quarter of 2004, 1,863,600 shares of PG&E Corporation common stock were repurchased through transactions with brokers and dealers on the New York Stock Exchange and/or the Pacific Exchange for an aggregate purchase price of approximately $60 million. Of this amount, 850,000 shares were purchased at a cost of approximately $28 million and are held by Elm Power Corporation.

December 2004 Accelerated Share Repurchase Arrangement

On December 15, 2004, PG&E Corporation entered into an accelerated share repurchase arrangement, or ASR, with Goldman Sachs & Co. Inc., or GS&Co., under which PG&E Corporation repurchased and retired 9,769,600 shares of its outstanding common stock for an initial aggregate purchase price of approximately $318 million, or $32.50 per share. PG&E Corporation recorded approximately $152 million to Common Stock and approximately $166 million to Reinvested Earnings within Common Shareholders' Equity with respect to this transaction. On February 22, 2005, PG&E Corporation paid GS&Co. an additional $14 million, the substantial majority of which represented a price adjustment based on the daily volume weighted average market price, or VWAP, of PG&E Corporation common stock over the term of the arrangement.

March 2005 Accelerated Share Repurchase Arrangement

On March 4, 2005, PG&E Corporation entered into another ASR, with GS&Co. under which PG&E Corporation repurchased and retired 29,489,400 shares of its outstanding common stock for an initial aggregate purchase price of approximately $1.05 billion or $35.60 per share. PG&E Corporation recorded approximately $460 million to Common Stock and approximately $591 million to Reinvested Earnings within Common Shareholders' Equity with respect to this transaction on September 12, 2005. PG&E Corporation paid GS&Co. an additional $22 million, the substantial majority of which represented a price adjustment based on the VWAP of PG&E Corporation common stock over the term of the arrangement.

November 2005 Accelerated Share Repurchase Arrangement

On November 16, 2005, PG&E Corporation entered into a third ASR with GS&Co. under which PG&E Corporation repurchased and retired 31,650,300 shares of its outstanding common stock for an initial aggregate purchase price of approximately $1.1 billion or $34.75 per share. PG&E Corporation recorded approximately $504 million to Common Stock and approximately $596 million to Reinvested Earnings within Common Shareholders' Equity with respect to this transaction.

Under the terms of the forward contract component of this ASR, certain additional payments may be required by both PG&E Corporation and GS&Co. Most significantly, PG&E Corporation may receive from, or be required to pay to, GS&Co. a price adjustment based on the VWAP of PG&E Corporation common stock over a period of approximately seven months. Over the remaining term of the ASR, for every $1 that the VWAP exceeds the initial per share price of $34.75, PG&E Corporation will owe GS&Co. an additional $24.8 million. Conversely, for every $1 that the VWAP is below $34.75, the amount due from GS&Co. will be reduced by $24.8 million.

PG&E Corporation's obligation under the ASR can be satisfied, at PG&E Corporation's option, in cash, in shares, or a combination of the two. Until the ASR is completed or terminated, GAAP requires PG&E Corporation to assume that it will issue shares to settle its obligations (up to a maximum of two times the number of shares repurchased or 63,300,600 shares). PG&E Corporation must calculate the number of shares that would be required to satisfy its obligations upon completion of the ASR based on the market price of PG&E Corporation's common stock at the end of a reporting period. The number of shares that would be required to satisfy the obligations must be treated as outstanding for purposes of calculating diluted EPS. Based on the market price of PG&E Corporation common stock at December 31, 2005, PG&E Corporation would have an obligation to GS&Co. of approximately $71 million upon the completion of the ASR. Accordingly, approximately 2 million additional shares of PG&E Corporation common stock attributable to the ASR were treated as outstanding for purposes of calculating diluted EPS.

UTILITY

The Utility is authorized to issue 800 million shares of its $5 par value common stock, of which 279,624,823 and 321,314,760 shares were issued and outstanding as of December 31, 2005 and 2004, respectively. PG&E Holdings, LLC, a wholly owned subsidiary of the Utility, holds 19,481,213 of the outstanding shares. PG&E Corporation and PG&E Holdings, LLC hold all of the Utility's outstanding common stock.

On March 8, 2005, the Utility used proceeds from the issuance of the first series of ERBs (see further discussion in Note 6) to repay debt and to repurchase 22,023,283 shares of its common stock from PG&E Corporation for an aggregate purchase price of approximately $960 million. As a result of this transaction, the Utility recorded reductions of approximately $141 million to Additional Paid-in Capital, approximately $110 million to Common Stock, and approximately $709 million to Reinvested Earnings within Shareholders' Equity.

On November 21, 2005, the Utility used proceeds from the second issuance of ERBs (see further discussion in Note 6) to repurchase an additional 19,666,654 shares of its common stock from PG&E Corporation for an aggregate purchase price of approximately $950 million. As a result of this transaction, the Utility recorded reductions of approximately $125 million to Additional Paid-in-Capital, approximately $98 million to Common Stock, and approximately $726 million to Reinvested Earnings within Shareholders' Equity.

The Utility may pay common stock dividends and repurchase its common stock provided cumulative preferred dividends on its preferred stock and mandatory preferred sinking fund payments are paid. As further discussed in Note 9, upon emergence from Chapter 11, on the effective date of the Utility's plan of reorganization, the Utility paid cumulative preferred dividends and preferred sinking fund payments related to 2004, 2003 and 2002.

DIVIDENDS

PG&E Corporation and the Utility did not declare or pay a dividend during the Utility's Chapter 11 proceeding as the Utility was prohibited from paying any common or preferred stock dividends without bankruptcy court approval and certain covenants in PG&E Corporation's Senior Secured Notes restricted the circumstances in which such a dividend could be declared or paid.

During 2005, the Utility paid cash dividends of $476 million on the Utility's common stock. Approximately $445 million in dividends were paid to PG&E Corporation and the remainder was paid to PG&E Holdings, LLC, a wholly owned subsidiary of the Utility that holds approximately 7% of the Utility's common stock.

On April 15, July 15 and October 17, 2005, PG&E Corporation paid a quarterly common stock dividend of $0.30 per share, totaling approximately $356 million. Of the total dividend payments made by PG&E Corporation in 2005, approximately $22 million was paid to Elm Power Corporation. In addition, during 2005, PG&E Corporation paid approximately $17 million in dividend equivalent payments with respect to its Convertible Subordinated Notes. On October 19, 2005, the PG&E Corporation Board of Directors approved an annual cash dividend target of $1.32 per share ($0.33 quarterly). On December 21, 2005, the Board of Directors declared a dividend of $0.33 per share, totaling approximately $122 million, that was payable to shareholders of record on December 30, 2005 on January 16, 2006.

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

PG&E Corporation did not declare or pay common or preferred stock dividends in 2004 or 2003.

NOTE 9: PREFERRED STOCK

PG&E Corporation has authorized 85 million shares of preferred stock, which may be issued as redeemable or non-redeemable preferred stock. No preferred stock of PG&E Corporation has been issued or is outstanding.

UTILITY

The Utility has authorized 75 million shares of $25 par value preferred stock, which may be issued as redeemable or non-redeemable preferred stock.

At December 31, 2005 and 2004, the Utility had issued and outstanding 5,784,825 shares of non-redeemable preferred stock without mandatory redemption provisions. Holders of the Utility's 5.0%, 5.5% and 6.0% series of non-redeemable preferred stock have rights to annual dividends ranging from $1.25 to $1.50 per share.

At December 31, 2005 and 2004, the Utility had issued and outstanding 4,534,958 and 5,973,456 shares of redeemable preferred stock without mandatory redemption provisions. 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, 2005, annual dividends ranged from $1.09 to $1.25 per share and redemption prices ranged from $25.75 to $27.25 per share.

There were no shares of the Utility's redeemable preferred stock with mandatory redemption provisions outstanding at December 31, 2005 due to the redemption of these shares on May 31, 2005, as discussed below. At December 31, 2004, the Utility's redeemable preferred stock with mandatory redemption provisions consisted of 2.375 million shares of the 6.30% series and 2.55 million shares of the 6.57% series. These series were redeemable at par value plus accumulated and unpaid dividends through the redemption date.

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. Due to the Utility's Chapter 11 proceeding, the Utility's Board of Directors did not declare or pay preferred stock dividends from January 31, 2001 through emergence from Chapter 11. On the effective date of the Utility's plan of reorganization, the Utility paid approximately $82 million in dividends. Throughout the remainder of 2004 the Utility paid dividends of approximately $19 million. During the year ended December 31, 2005, the Utility paid approximately $16 million of dividends on preferred stock without mandatory redemption provisions and approximately $5 million of dividends on preferred stock with mandatory redemption provisions. 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.

Redemption of Preferred Stock with Mandatory Redemption Provisions

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

Redemption of Preferred Stock without Mandatory Redemption Provisions

On June 15, 2005, the Utility's Board of Directors authorized the redemption of all of the outstanding shares of the Utility's 7.04% Redeemable First Preferred Stock totaling approximately $36 million aggregate par value plus approximately $1 million related to a $0.70 redemption premium. This issue was fully redeemed on August 31, 2005. In addition to the $25 per share redemption price, holders of the 7.04% Redeemable First Preferred Stock received an amount equal to all accumulated and unpaid dividends through August 31, 2005 on such shares totaling approximately $211,000.

NOTE 10: EARNINGS PER SHARE

Earnings per common share is calculated, utilizing the "two-class" method, by dividing the sum of distributed earnings to common shareholders and undistributed earnings allocated to common shareholders by the weighted average number of common shares outstanding during the period. In applying the "two-class" method, undistributed earnings are allocated to both common shares and participating securities. PG&E Corporation's Convertible Subordinated Notes, are entitled to receive (non-cumulative) dividend payments prior to exercising the conversion option and meet the criteria of a participating security. The Convertible Subordinated Notes are convertible at the option of the holders into 18,558,655 common shares. All PG&E Corporation's participating securities participate on a 1:1 basis in dividends with common shareholders.

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

(in millions, except per share amounts)	Year ended December 31, 2005	2004	2003
Net Income	$ 917	$4,504	$ 420
Less: distributed earnings to common shareholders	449	–	–
Undistributed earnings	468	4,504	420
Less: undistributed earnings (loss) from discontinued operations	13	684	(365)
Undistributed earnings before cumulative effect of changes in accounting principles	455	3,820	785
Less: undistributed earnings (loss) from cumulative effect of changes in accounting principles	–	–	(6)
Undistributed earnings from continuing operations	$ 455	$3,820	$ 791
Common shareholders earnings			
Basic			
Distributed earnings to common shareholders	$ 449	$ –	$ –
Undistributed earnings allocated to common shareholders – continuing operations	433	3,646	754
Undistributed earnings (loss) allocated to common shareholders – discontinued operations	12	653	(348)
Undistributed earnings (loss) allocated to common shareholders – cumulative effect of changes in accounting principles	–	–	(6)
Total common shareholders earnings, basic	$ 894	$4,299	$ 400
Diluted			
Distributed earnings to common shareholders	$ 449	$ –	$ –
Undistributed earnings allocated to common shareholders – continuing operations	433	3,650	755
Undistributed earnings (loss) allocated to common shareholders – discontinued operations	12	653	(348)
Undistributed earnings (loss) allocated to common shareholders – cumulative effect of changes in accounting principles	–	–	(6)
Total common shareholders earnings, diluted	$ 894	$4,303	$ 401
Weighted average common shares outstanding, basic	372	398	385
9.50% Convertible Subordinated Notes	19	19	19
Weighted average common shares outstanding and participating securities, basic	391	417	404
Weighted average common shares outstanding, basic	372	398	385
Employee stock-based compensation and accelerated share repurchase program[1]	6	7	4
PG&E Corporation warrants	–	2	5
Weighted average common shares outstanding, diluted	378	407	394
9.50% Convertible Subordinated Notes	19	19	19
Weighted average common shares outstanding and participating securities, diluted	397	426	413
Net earnings per common share, basic			
Distributed earnings, basic[2]	$1.21	$ –	$ –
Undistributed earnings – continuing operations, basic	1.16	9.16	1.96
Undistributed earnings (loss) – discontinued operations, basic	0.03	1.64	(0.90)
Undistributed earnings (loss) – cumulative effect of changes in accounting principles	–	–	(0.01)
Rounding	–	–	(0.01)
Total	$2.40	$10.80	$ 1.04
Net earnings per common share, diluted			
Distributed earnings, diluted	$1.19	$ –	$ –
Undistributed earnings – continuing operations, diluted	1.15	8.97	1.92
Undistributed earnings (loss) – discontinued operations, diluted	0.03	1.60	(0.88)
Undistributed earnings (loss) – cumulative effect of changes in accounting principles	–	–	(0.01)
Rounding	–	–	(0.01)
Total	$2.37	$10.57	$ 1.02

(1) Includes approximately 2 million shares and 222,000 shares, respectively, of PG&E Corporation common stock potentially issuable in settlement of an obligation of PG&E Corporation of approximately $71 million and $7.4 million, respectively, under an ASR at December 31, 2005 and December 31, 2004, respectively. See Note 8 for further discussion. The remaining shares, approximately 4 million at December 31, 2005 and 6.8 million shares at December 31, 2004, are deemed to be outstanding per SFAS No. 128 for the purpose of calculating EPS. See section of Note 2 entitled "Earnings Per Share."

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

Options to purchase PG&E Corporation common shares of 28,500 in 2005, 7,046,710 in 2004 and 16,008,087 in 2003 were outstanding, but not included in the computation of diluted EPS because the option exercise prices were greater than the average market price.

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

NOTE 11: INCOME TAXES

The significant components of income tax (benefit) expense for continuing operations were:

	PG&E Corporation			Utility		
	Year Ended December 31,					
(in millions)	2005	2004	2003	2005	2004	2003
Current:						
Federal	$1,027	$ 121	$ 61	$1,048	$ 73	$524
State	189	91	41	196	85	171
Deferred:						
Federal	(574)	1,877	422	(572)	2,000	(88)
State	(89)	384	(49)	(89)	410	(62)
Tax credits, net	(9)	(7)	(17)	(9)	(7)	(17)
Income tax expense	$ 544	$2,466	$458	$ 574	$2,561	$528

The following describes net deferred income tax liabilities:

	PG&E Corporation		Utility	
	Year ended December 31,			
(in millions)	2005	2004	2005	2004
Deferred income tax assets:				
Customer advances for construction	$ 607	$ 472	$ 607	$ 472
Unamortized investment tax credits	106	108	106	108
Reserve for damages	276	270	276	270
Environmental reserve	188	194	188	194
Other	366	151	260	70
Total deferred income tax assets	$1,543	$1,195	$1,437	$1,114
Deferred income tax liabilities:				
Regulatory balancing accounts	$1,719	$2,097	$1,719	$2,097
Property related basis differences	2,694	2,413	2,694	2,413
Income tax regulatory asset	218	209	218	209
Unamortized loss on reacquired debt	128	137	128	137
Other	57	264	57	264
Total deferred income tax liabilities	$4,816	$5,120	$4,816	$5,120
Total net deferred income tax liabilities	$3,273	$3,925	$3,379	$4,006
Classification of net deferred income tax liabilities:				
Included in current liabilities	$ 181	$ 394	$ 161	$ 377
Included in noncurrent liabilities	3,092	3,531	3,218	3,629
Total net deferred income tax liabilities	$3,273	$3,925	$3,379	$4,006

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

	PG&E Corporation			Utility		
	Year Ended December 31,					
	2005	2004	2003	2005	2004	2003
Federal statutory income tax rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) in income tax rate resulting from:						
State income tax (net of federal benefit)	4.5	4.6	4.7	4.7	4.7	4.9
Effect of regulatory treatment of depreciation differences	0.9	(0.5)	(2.9)	0.9	(0.4)	(2.5)
Tax credits, net	(1.0)	(0.2)	(1.7)	(1.0)	(0.2)	(1.5)
Other, net	(1.8)	0.3	1.3	(1.6)	0.2	0.5
Effective tax rate	37.6%	39.2%	36.4%	38.0%	39.3%	36.4%

The IRS has completed its audit of PG&E Corporation's 1997 and 1998 consolidated federal income tax returns and has assessed additional federal income taxes of approximately $81 million (including interest). PG&E Corporation has filed protests contesting certain adjustments made by the IRS in that audit and currently is discussing these adjustments with the IRS Appeals Office.

The IRS also has completed its audit of PG&E Corporation's 1999 and 2000 consolidated federal income tax returns and refunded $14 million to PG&E Corporation. As a result of the resolution of this audit, in the second quarter of 2005, PG&E Corporation paid the Utility $18 million relating to the Utility matters that had been included in the audit, the Utility reduced its reserve for outstanding tax audits by $11 million and PG&E Corporation recognized tax benefits of $32 million for NEGT-related matters included in the audit.

The IRS is currently auditing PG&E Corporation's 2001 and 2002 consolidated federal income tax returns. The IRS has indicated that it plans to continue the audit into 2006. At the beginning of its examination the IRS indicated it would disallow synthetic fuel credits claimed by PG&E Corporation. In January 2006, a partnership which owned a portion of those synthetic fuel facilities received a letter from the IRS disallowing approximately $40 million of synthetic fuel credits. These credits are part of $104 million of synthetic fuel credits claimed by PG&E Corporation in its 2001 and 2002 consolidated federal income tax returns. PG&E Corporation expects the IRS to take similar action with respect to the remaining $64 million of synthetic fuel credits claimed in its 2001 and 2002 consolidated federal income tax returns. In addition, the IRS has proposed to disallow a number of deductions, the largest of which is a deduction for abandoned or worthless assets owned by NEGT. PG&E Corporation believes that it properly reported these transactions in its tax returns and will contest any IRS assessment. If the IRS includes all of its proposed disallowances in the final Revenue Agent Report, the alleged tax deficiency would approximate $452 million. Of this deficiency, approximately $104 million relates to the synthetic fuel credits and approximately $316 million is of a timing nature, which would be refunded to PG&E Corporation in the future. In the second quarter of 2005, PG&E Corporation increased its reserve with respect to NEGT tax issues included in the 2001 and 2002 consolidated federal income tax returns by $32 million.

The IRS began its audit of PG&E Corporation's 2003 and 2004 tax returns in the third quarter of 2005.

During the third quarter of 2005, PG&E Corporation received additional information from NEGT regarding income to be included in PG&E Corporation's 2004 federal income tax return. This information was incorporated in the 2004 tax return, which was filed with the IRS in September 2005. As a result, the 2004 federal income tax liability was reduced by approximately $19 million. In addition, NEGT provided additional information with respect to amounts previously included in PG&E Corporation's 2003 federal income tax return. This change resulted in PG&E Corporation's 2003 federal income tax liability increasing by approximately $6 million. These two adjustments, netting to $13 million, were recognized in income from discontinued operations in the third quarter of 2005.

As of December 31, 2005, PG&E Corporation has accrued approximately $138 million to cover potential tax obligations and interest related to outstanding audits, including the $89 million related to NEGT issues discussed above, and $49 million to cover potential tax obligations related to non-NEGT issues. The increase in PG&E Corporation's accrual at December 31, 2005, compared to December 31, 2004, of approximately $37 million is primarily related to the second quarter increase of $32 million in the accrual for NEGT tax issues included in the 2001–2002 audit discussed above.

As of December 31, 2005, the Utility has accrued approximately $52 million to cover potential tax obligations discussed above, including interest, related to outstanding audits. This represents an $11 million reduction from the accrual at December 31, 2004, and reflects the resolution of the 1999–2000 audit discussed above.

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

NOTE 12: RISK MANAGEMENT ACTIVITIES

As discussed in Note 7, NEGT's financial results are no longer consolidated with those of PG&E Corporation following the July 8, 2003 Chapter 11 filing of NEGT. NEGT's financial results through July 7, 2003 are reflected in discontinued operations. Because NEGT's financial results are no longer consolidated with those of PG&E Corporation, the only risk management activities currently reported by PG&E Corporation are related to the Utility's non-trading activities, which are executed on a non-trading basis.

COMMODITY PROCUREMENT ACTIVITIES

The Utility enters into contracts to procure electricity, natural gas, nuclear fuel and firm transmission rights. Except for contracts that meet the definition of normal purchases and sales, all derivative contracts including contracts designated as cash flow hedges of natural gas in the natural gas portfolios are recorded at fair value and presented as price risk management assets and liabilities on the balance sheet. On PG&E Corporation's and the Utility's Consolidated Balance Sheets, price risk management activities consist of $140 million in Current Assets – Prepaid expenses and other and $212 million in Other Non-Current Assets – Other, and $2 million in Current Liabilities – Other, as of December 31, 2005, and $5 million in Current Assets – Prepaid expenses and other and $11 million in Current Liabilities – Other as of December 31, 2004. However, since these contracts are used within the regulatory framework, regulatory accounts are recorded to offset the costs and proceeds of these derivatives recognized in earnings and subsequently recovered in regulated rates charged to customers.

CREDIT RISK

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

Additionally, the Utility has a concentration of credit risk associated with its wholesale customers and counterparties mainly in the energy industry, including other California investor-owned electric utilities, municipal utilities, energy trading companies, financial institutions, and oil and natural gas production companies located in the United States and Canada. This concentration of counterparties may impact the Utility's overall exposure to credit risk because counterparties may be similarly affected by economic or regulatory changes, or other changes in conditions. If a counterparty failed to perform on their contractual obligation to deliver electricity, then the Utility will be required to procure electricity at current market prices, which may be higher than those originally contracted for. However, credit losses attributable to receivables and electrical and gas procurement activities from both retail and wholesale customers and counterparties are expected to be recoverable from customers through rates and are, therefore, not expected to have a material impact on earnings. See Note 17 for further discussion of supplier concentrations.

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

annually. Further, the Utility relies on master agreements that require security, referred to as credit collateral, in the form of cash, letters of credit, corporate guarantees of acceptable credit quality, or eligible securities if current net receivables and replacement cost exposure exceed contractually specified limits.

The schedule below summarizes the Utility's net credit risk exposure to its wholesale customers and counterparties, as well as the Utility's credit risk exposure to its wholesale customers or counterparties with a greater than 10% net credit exposure, at December 31, 2005 and December 31, 2004:

(in millions)	Gross Credit Exposure Before Credit Collateral[1]	Credit Collateral	Net Credit Exposure[2]	Number of Wholesale Customer or Counterparties >10%	Net Exposure to Wholesale Customer or Counterparties >10%
December 31, 2005	$447	$105	$342	3	$165
December 31, 2004	$105	$ 7	$ 98	3	$ 62

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

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

NOTE 13: NUCLEAR DECOMMISSIONING

The Utility's nuclear power facilities consist of two units at Diablo Canyon and the retired facility at Humboldt Bay Unit 3. Nuclear decommissioning requires the safe removal of nuclear facilities from service and the reduction of residual radioactivity to a level that permits termination of the NRC license and release of the property for unrestricted use. For ratemaking purposes, the eventual decommissioning of Diablo Canyon Unit 1 is scheduled to begin in 2021 and to be completed in 2041. Decommissioning of Diablo Canyon Unit 2 is scheduled to begin in 2025 and to be completed in 2041, and decommissioning of Humboldt Bay Unit 3 is scheduled to begin in 2009 and to be completed in 2015.

As presented in the Utility's Nuclear Decommissioning Costs Triennial Proceeding (NDCTP), the estimated nuclear decommissioning cost for the Diablo Canyon Units 1 and 2 and Humboldt Bay Unit 3 is approximately $2.03 billion in 2005 dollars (or approximately $5.12 billion in future dollars). These estimates are based on the 2005 decommissioning cost studies, prepared in accordance with CPUC requirements. The Utility's revenue requirements for nuclear decommissioning costs are recovered from customers through a non-bypassable charge that will continue until those costs are fully recovered. The decommissioning cost estimates are based on the plant location and cost characteristics for the Utility's nuclear power plants. Actual decommissioning costs may vary from these estimates as a result of changes in assumptions such as decommissioning dates, regulatory requirements, technology, and costs of labor, materials and equipment.

The estimated nuclear decommissioning cost described above is used for regulatory purposes. Decommissioning costs recovered in rates are placed in nuclear decommissioning trusts. However, under GAAP requirements, the decommissioning cost estimate is calculated using a different method. In accordance with SFAS No. 143, the Utility adjusts its nuclear decommissioning obligation to reflect the fair value of decommissioning its nuclear power facilities. The Utility records the Utility's total nuclear decommissioning obligation as an asset retirement obligation on the Utility's Consolidated Balance Sheet. Decommissioning costs are recorded as a component of depreciation expense, with a corresponding credit to the asset retirement costs regulatory liability. The total nuclear decommissioning obligation accrued in accordance with GAAP was approximately $1.3 billion at December 31, 2005 and $1.2 billion at December 31, 2004. The primary difference between the Utility's estimated nuclear decommissioning obligation as recorded in accordance with GAAP and the estimate prepared in accordance with the CPUC requirements is that GAAP incorporates various potential settlement dates for the obligation and includes an estimated amount for third-party labor costs into the fair value calculation.

The Utility has three decommissioning trusts for its Diablo Canyon and Humboldt Bay Unit 3 nuclear facilities. The Utility has elected that two of these trusts be treated

under the Internal Revenue Code as qualified trusts. If certain conditions are met, the Utility is allowed a deduction for the payments made to the qualified trusts. These payments cannot exceed the amount collected from customers through the decommissioning revenue requirement. The qualified trusts are subject to a lower tax rate on income and capital gains, thereby increasing the trusts' after-tax returns. Among other requirements, to maintain the qualified trust status the IRS must approve the amount to be contributed to the qualified trusts for any taxable year. The remaining non-qualified trust is exclusively for decommissioning Humboldt Bay Unit 3. The Utility cannot deduct amounts contributed to the non-qualified trust until such decommissioning costs are actually incurred.

As authorized in the 2002 NDCTP, in 2005, the Utility was authorized to collect approximately $18.4 million in rates and contributed approximately $18.4 million to the qualified nuclear decommissioning trust for Humboldt Bay Unit 3. For 2006, the Utility is authorized to collect approximately $18.4 million in rates for decommissioning Humboldt Bay Unit 3. The Utility expects to contribute that entire amount to the qualified trusts for Humboldt Bay Unit 3. The Utility has received approval from the IRS to contribute all of the collected amounts to the qualified trust for Humboldt Bay Unit 3 for 2005. The Utility expects to file a ruling request with the IRS in the first quarter of 2006 for contributions made in 2006. The CPUC issued a decision in the 2002 NDCTP finding that the funds in the Diablo Canyon nuclear decommissioning trusts are sufficient to pay for the eventual decommissioning. Therefore, no contributions were made to the Diablo Canyon trusts in 2005 and no contributions are expected for 2006.

On November 10, 2005, the Utility filed its 2005 NDCTP, seeking approval for its proposed nuclear decommissioning revenue requirements for the years 2007–2009. The Utility's 2005 NDCTP seeks recovery of $9.5 million in revenue requirements relating to the qualified trust for Diablo Canyon and $14.6 million in revenue requirements relating to the qualified trust for Humboldt Bay Unit 3. The Utility expects to begin evidentiary hearings with the CPUC in May 2006 and expects a decision in October 2006.

The funds in the decommissioning trusts, along with accumulated earnings, will be used exclusively for decommissioning and dismantling the Utility's nuclear facilities. The trusts maintain substantially all of their investments in debt and equity securities. The CPUC has authorized the qualified trust to invest a maximum of 50% of its funds in publicly-traded equity securities, of which up to 20% may be invested in publicly-traded non-U.S. equity securities. For the non-qualified trust, no more than 60% may be invested in publicly-traded equities, of which up to 20% may be invested in publicly-traded non-U.S. equity securities. The allocation of the trust funds is monitored monthly. To the extent that market movements cause the asset allocation to move outside these ranges, the investments are rebalanced toward the target allocation.

The Utility estimates after-tax annual earnings, including realized gains and losses, in the qualified trusts to be 6.5% and in the non-qualified trusts to be 5.6%. Trust earnings are included in the nuclear decommissioning trust assets and corresponding SFAS No. 143 regulatory liability. There is no impact on the Utility's earnings. Annual returns decrease in later years as higher portions of the trusts are dedicated to fixed income investments leading up to and during the entire course of decommissioning activities.

All earnings on the assets held in the trusts, net of authorized disbursements from the trusts and investment management and administrative fees, are reinvested. Amounts may not be released from the decommissioning trusts until authorized by the CPUC. At December 31, 2005, the Utility had accumulated nuclear decommissioning trust funds with an estimated fair value of approximately $1.7 billion, based on quoted market prices and net of deferred taxes on unrealized gains.

In general, investment securities are exposed to various risks, such as interest rate, credit and market volatility risks. Due to the level of risk associated with certain investment securities, it is reasonably possible that changes in the market values of investment securities could occur in the near term, and such changes could materially affect the trusts' fair value.

The Utility records unrealized gains and losses on investments held in the trusts in other comprehensive income in accordance with SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities." Realized gains and losses are recognized as additions or reductions to trust asset balances. The Utility, however, accounts for its nuclear decommissioning obligations in accordance with SFAS No. 71. Therefore, both realized and unrealized gains and losses are ultimately recorded as regulatory assets or liabilities.

In 2005, total unrealized losses on the investments held in the trust were $3 million, all of which were in an unrealized loss position for less than twelve months. Based on the Utility's ability and intent to hold such investments for a reasonable period of time sufficient for a projected recovery of fair value, the Utility does not consider these investments to be other-than-temporarily impaired as of December 31, 2005.

The following table provides a summary of the fair value, based on quoted market prices, of the investments held in the Utility's nuclear decommissioning trusts:

(in millions)	Maturity Date	Total Unrealized Gains	Total Unrealized Losses	Estimated Fair Value
Year ended December 31, 2005				
U.S. government and agency issues	2006–2035	$ 42	$(2)	$ 763
Municipal bonds and other	2006–2036	10	(1)	192
Equity securities		534	–	871
Total		$586	$(3)	$1,826
Year ended December 31, 2004				
U.S. government and agency issues	2005–2033	$ 47	$–	$ 681
Municipal bonds and other	2005–2034	14	–	181
Equity securities		523	–	880
Total		$584	$–	$1,742

The cost of debt and equity securities sold is determined by specific identification. The following table provides a summary of the activity for the debt and equity securities:

	Year Ended December 31,		
(in millions)	2005	2004	2003
Proceeds received from sales of securities	$2,918	$1,821	$1,087
Gross realized gains on sales of securities held as available-for-sale	56	28	27
Gross realized losses on sales of securities held as available-for-sale	(14)	(22)	(44)

SPENT NUCLEAR FUEL STORAGE PROCEEDINGS

Under the Nuclear Waste Policy Act of 1982, the Department of Energy, or the DOE, is responsible for the transportation and permanent storage and disposal of spent nuclear fuel and high-level radioactive waste. The Utility has signed a contract with the DOE to provide for the disposal of spent nuclear fuel and high-level radioactive waste from the Utility's two nuclear power facilities at Diablo Canyon. Under the Utility's contract with the DOE, if the DOE completes a storage facility by 2010, the earliest that Diablo Canyon's spent fuel would be accepted for storage or disposal is thought to be 2018. At the projected level of operation for Diablo Canyon, the Utility's current facilities are able to store on-site all spent fuel produced through approximately 2007. In March 2004, the NRC authorized the Utility to build an on-site dry cask storage facility to store spent fuel through approximately 2021 for Unit 1 and to 2024 for Unit 2. Several interveners in that proceeding filed an appeal of the NRC's decision with the U.S. Court of Appeals for the Ninth Circuit, or the Ninth Circuit. The Ninth Circuit heard oral argument on that appeal in October 2005, and a decision is pending. PG&E Corporation and the Utility cannot predict the outcome of this appeal.

Construction of the on-site dry cask storage facility began in the third quarter of 2005 and is expected to be completed by 2008. In November 2005, the NRC authorized the Utility to install a temporary storage rack in each unit's existing spent fuel storage pool that would permit the Utility to operate Unit 1 until 2010 and Unit 2 until 2011. The Utility anticipates that it would complete the installa-

tion of the temporary storage racks by December 2006. If the Utility is unable to complete the dry cask storage facility, or if construction is delayed beyond 2010, and if the Utility is otherwise unable to increase its on-site storage capacity, it is possible that the operation of Diablo Canyon may have to be curtailed or halted as early as 2010 with respect to Unit 1 and 2011 with respect to Unit 2 and until such time as additional spent fuel can be safely stored. If electricity from Diablo Canyon were unavailable, the Utility would be required to purchase electricity from other more expensive sources to meet its customers' demand.

NOTE 14: EMPLOYEE COMPENSATION PLANS

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

Under SFAS No. 71, regulatory adjustments are recorded in the Consolidated Statements of Income and Consolidated Balance Sheets of the Utility to reflect the difference between Utility pension expense or income for accounting purposes and Utility pension expense or income for ratemaking, which is based on a funding approach. The CPUC has authorized the Utility to recover the costs associated with its other benefits for 1993 and beyond. Recovery is based on the lesser of the amounts collected in rates or the annual contributions on a tax-deductible basis to the appropriate trusts.

BENEFIT OBLIGATIONS

The following tables reconcile changes in aggregate projected benefit obligations for pension benefits and changes in the benefit obligation of other benefits during 2005 and 2004:

Pension Benefits

	PG&E Corporation		Utility	
(in millions)	2005	2004	2005	2004
Projected benefit obligation at January 1	$8,557	$7,516	$8,551	$7,509
Service cost for benefits earned	214	194	211	194
Interest cost	500	482	498	482
Plan amendments	(7)	28	(3)	28
Actuarial loss	331	667	326	667
Settlement	—	—	—	—
Benefits and expenses paid	(348)	(330)	(347)	(329)
Other[1]	2	—	(25)	—
Projected benefit obligation at December 31	$9,249	$8,557	$9,211	$8,551
Accumulated benefit obligation	$8,276	$7,638	$8,246	$7,632

(1) In 2004, the pension benefits included a Supplemental Executive Retirement Plan sponsored by the Utility. In 2005, this plan was split into two plans. The Utility remained sponsor of the first plan and PG&E Corporation became the sponsor of the second plan.

Other Benefits

(in millions)	PG&E Corporation 2005	PG&E Corporation 2004	Utility 2005	Utility 2004
Benefit obligation at January 1	$1,399	$1,444	$1,399	$1,444
Service cost for benefits earned	30	32	30	32
Interest cost	74	85	74	85
Actuarial loss	(103)	(103)	(103)	(103)
Participants paid benefits	30	30	30	30
Plan amendments	—	—	—	—
Benefits paid	(91)	(89)	(91)	(89)
Benefit obligation at December 31	$1,339	$1,399	$1,339	$1,399

CHANGE IN PLAN ASSETS

To determine the fair value of the plan assets, PG&E Corporation and the Utility use publicly quoted market values and independent pricing services depending on the nature of the assets, as reported by the trustee.

The following tables reconcile aggregate changes in plan assets during 2005 and 2004:

Pension Benefits

(in millions)	PG&E Corporation 2005	PG&E Corporation 2004	Utility 2005	Utility 2004
Fair value of plan assets at January 1	$7,614	$7,129	$7,614	$7,129
Actual return on plan assets	758	787	758	787
Company contributions	25	27	24	27
Settlement	—	—	—	—
Benefits and expenses paid	(348)	(329)	(347)	(329)
Fair value of plan assets at December 31	$8,049	$7,614	$8,049	$7,614

Other Benefits

(in millions)	PG&E Corporation 2005	PG&E Corporation 2004	Utility 2005	Utility 2004
Fair value of plan assets at January 1	$1,069	$ 955	$1,069	$ 955
Actual return on plan assets	86	108	86	108
Company contributions	59	71	59	71
Plan participant contribution	30	30	30	30
Benefits and expenses paid	(98)	(95)	(98)	(95)
Fair value of plan assets at December 31	$1,146	$1,069	$1,146	$1,069

FUNDED STATUS

The following schedule reconciles the plans' aggregate funded status to the prepaid or accrued benefit cost on a plan sponsor basis. The funded status is the difference between the fair value of plan assets and projected benefit obligations.

Pension Benefits

	PG&E Corporation		Utility	
	December 31,		December 31,	
(in millions)	2005	2004	2005	2004
Fair value of plan assets at December 31	$ 8,049	$ 7,614	$ 8,049	$ 7,614
Projected benefit obligation at December 31	(9,249)	(8,557)	(9,211)	(8,551)
Funded status plan assets less than projected benefit obligation	(1,200)	(943)	(1,162)	(937)
Unrecognized prior service cost	321	378	327	378
Unrecognized net loss	1,314	1,148	1,302	1,148
Unrecognized net transition obligation	1	2	–	2
Prepaid benefit cost	$ 436	$ 585	$ 467	$ 591
Prepaid benefit cost	$ 491	$ 638	$ 491	$ 638
Accrued benefit liability	(55)	(53)	(24)	(47)
Additional minimum liability	(671)	–	(668)	–
Intangible asset	332	–	332	–
Excess additional minimum liability[1]	339	–	336	–
Prepaid benefit cost	$ 436	$ 585	$ 467	$ 591

(1) Of this amount, approximately $325 million has been recorded as a reduction to a pension regulatory liability in accordance with the provisions of SFAS No. 71 and the remainder is recorded to other comprehensive income, net of the related income tax benefit, for the year ended December 31, 2005.

PG&E Corporation has participants in the Utility's Retirement Plan, Retirement Excess Benefit Plan and the Supplemental Executive Retirement Plan. PG&E Corporation's obligation for its participants in these plans was approximately $12 million at December 31, 2005 and $19 million at December 31, 2004.

Other Benefits

	PG&E Corporation		Utility	
	December 31,		December 31,	
(in millions)	2005	2004	2005	2004
Fair value of plan assets at December 31	$ 1,146	$ 1,069	$ 1,146	$ 1,069
Benefit obligation at December 31	(1,339)	(1,399)	(1,339)	(1,399)
Funded status plan assets less than benefit obligation	(193)	(330)	(193)	(330)
Unrecognized prior service cost	132	110	132	110
Unrecognized net loss (gain)	(129)	1	(129)	1
Unrecognized net transition obligation	179	205	179	205
Accrued benefit cost	$ (11)	$ (14)	$ (11)	$ (14)
Prepaid benefit cost	$ –	$ –	$ –	$ –
Accrued benefit liability	(11)	(14)	(11)	(14)
Additional minimum liability	–	–	–	–
Accrued benefit cost	$ (11)	$ (14)	$ (11)	$ (14)

PG&E Corporation has participants in the Utility's Postretirement Medical Plan and Postretirement Life Insurance Plan. PG&E Corporation's obligation for its participants in these plans was approximately $1 million at December 31, 2005 and 2004.

OTHER INFORMATION

The aggregate projected benefit obligation, accumulated benefit obligation and fair value of plan assets for plans in which the fair value of plan assets is less than the accumulated benefit obligation as of December 31, 2005 and 2004 were as follows:

	Pension Benefits		Other Benefits	
(in millions)	2005	2004	2005	2004
PG&E Corporation:				
Projected benefit obligation	$(9,249)	$(8,557)	$(1,339)	$(1,399)
Accumulated benefit obligation	(8,276)	(7,638)	–	–
Fair value of plan assets	8,049	7,614	1,146	1,069
Utility:				
Projected benefit obligation	$(9,211)	$(8,551)	$(1,339)	$(1,399)
Accumulated benefit obligation	(8,246)	(7,632)	–	–
Fair value of plan assets	8,049	7,614	1,146	1,069

COMPONENTS OF NET PERIODIC BENEFIT COST

Net periodic benefit cost as reflected in PG&E Corporation's Consolidated Statements of Income for the years ended December 31, 2005, 2004 and 2003 is as follows:

Pension Benefits

	December 31,		
(in millions)	2005	2004	2003
Service cost for benefits earned	$ 215	$ 194	$ 170
Interest cost	500	482	446
Expected return on plan assets	(623)	(563)	(507)
Amortized prior service cost	55	63	56
Amortization of unrecognized loss	29	6	46
Settlement loss	–	–	1
Net periodic benefit cost	$ 176	$ 182	$ 212

Other Benefits

	December 31,		
(in millions)	2005	2004	2003
Service cost for benefits earned	$ 30	$ 32	$ 29
Interest cost	74	84	79
Expected return on plan assets	(85)	(76)	(61)
Amortized prior service cost	37	38	28
Amortization of unrecognized loss (gain)	(1)	–	1
Net periodic benefit cost	$ 55	$ 78	$ 76

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

Valuation Assumptions

The following actuarial assumptions were used in determining the projected benefit obligations and the net periodic cost. Weighted average, year-end assumptions were used in determining the plans' projected benefit obligations, while prior year-end assumptions are used to compute net benefit cost.

	Pension Benefits			Other Benefits		
	December 31,			December 31,		
	2005	2004	2003	2005	2004	2003
Discount rate	5.60%	5.80%	6.25%	5.20–5.65%	5.80%	6.25%
Average rate of future compensation increases	5.00%	5.00%	5.00%	–	–	–
Expected return on plan assets						
Pension benefits	8.00%	8.10%	8.10%	–	–	–
Other benefits:						
Defined benefit – medical plan bargaining	–	–	–	8.40%	8.50%	8.50%
Defined benefit – medical plan non-bargaining	–	–	–	7.60%	7.60%	7.60%
Defined benefit – life insurance plan	–	–	–	8.40%	8.50%	8.50%

The assumed health care cost trend rate for 2006 is approximately 9%, decreasing gradually to an ultimate trend rate in 2010 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	$68	$(54)
Effect on service and interest cost	8	(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 trusts, resulting in a weighted average rate of return on plan assets. Fixed income projected returns were based on historical returns for the broad U.S. bond market. Equity returns were based primarily on historical returns of the S&P 500 Index. For the Utility Retirement Plan, the assumed return of 8.0% compares to a 10-year actual return of 9.0%. The rate used to discount pension and other postretirement benefit plan liabilities was based on a yield curve developed from the Moody's AA Corporate Bond Index at December 31, 2005. This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other postretirement obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

The difference between actual and expected return on plan assets is included in net amortization and deferral, and is considered in the determination of future net benefit income (cost). The actual return on plan assets was above the expected return in 2005, 2004 and 2003.

ASSET ALLOCATIONS

The asset allocation of PG&E Corporation's and the Utility's pension and other benefit plans at December 31, 2005 and 2004, and target 2006 allocation, was as follows:

	Pension Benefits			Other Benefits		
	2006	2005	2004	2006	2005	2004
Equity securities						
U.S. equity	40%	41%	43%	51%	51%	51%
Non-U.S. equity	20%	24%	22%	20%	20%	21%
Fixed income securities	40%	35%	35%	29%	29%	28%
Total	100%	100%	100%	100%	100%	100%

Equity securities include a small amount (less than 0.1% of total plan assets) of PG&E Corporation common stock.

The maturity of fixed income securities at December 31, 2005 and 2004 ranges from zero to 55 years and the average duration of the bond portfolio is approximately 4.1 years.

PG&E Corporation's and the Utility's investment strategy for all plans is to maintain actual asset weightings within 5% of the target asset allocations. Whenever the actual weighting exceeds the target weighting by 5%, the asset holdings are rebalanced.

A benchmark portfolio for each asset class is set based on market capitalization and valuations of equities and the durations and credit quality of fixed income securities. Investment managers for each asset class are retained to periodically adjust, or actively manage, the combined portfolio against the benchmark. Active management covers approximately 70% of the U.S. equity, 60% of the non-U.S. equity, and virtually 100% of the fixed income security portfolios.

CASH FLOW INFORMATION

Employer Contributions

PG&E Corporation and the Utility expect to contribute approximately $273 million to the Pension Benefits Plan to fund voluntary retirement program obligations, and approximately $65 million to the Other Benefits plans in 2006. These contributions will be consistent with PG&E Corporation's and the Utility's funding policy, which is to contribute amounts that are tax deductible, consistent with applicable regulatory decisions and sufficient to meet minimum funding requirements. None of these benefit plans are subject to a minimum funding requirement in 2006. The Utility's pension benefit plans met all the funding requirements under the Employee Retirement Income Security Act of 1974, as amended.

Benefits Payments

The estimated benefits expected to be paid in each of the next five fiscal years and in aggregate for the five fiscal years thereafter, are as follows:

(in millions)	PG&E Corporation	Utility
Pension		
2006	$ 372	$ 370
2007	393	392
2008	417	415
2009	442	440
2010	468	466
2011–2015	2,756	2,743
Other benefits		
2006	$ 82	$ 82
2007	82	82
2008	84	84
2009	85	85
2010	87	87
2011–2015	474	474

DEFINED CONTRIBUTION PENSION PLAN

PG&E Corporation and its subsidiaries also sponsor defined contribution pension plans. These plans are qualified under applicable sections of the Code. These plans provide for tax-deferred salary deductions and after-tax employee contributions as well as employer contributions. Employees designate the funds in which their contributions and any employer contributions are invested. Employer contributions include matching of up to 5% of an employee's base compensation and/or basic contributions of up to 5% of an employee's base compensation. Matching employer contributions are automatically invested in PG&E Corporation common stock. Employees may reallocate matching employer contributions and accumulated earnings thereon to another investment fund or funds available to the plan at any time after they have been credited to the employee's account. Employer contribution expense reflected in PG&E Corporation's Consolidated Statements of Income amounted to:

(in millions)	PG&E Corporation	Utility
Year ended December 31,		
2005	$43	$42
2004	40	39
2003[1]	38	37

(1) Includes NEGT-related amounts within PG&E Corporation.

LONG-TERM INCENTIVE PROGRAM

PG&E Corporation has awarded stock options, restricted stock and other stock-based incentive awards to executive officers and other employees of PG&E Corporation and its subsidiaries under the PG&E Corporation Long-Term Incentive Program. Non-employee directors of PG&E Corporation were also eligible to receive restricted stock and either stock options or phantom stock under the formula grant provisions of the PG&E Corporation Long-Term Incentive Program. Although the PG&E Corporation Long-Term Incentive Program expired on December 31, 2005, outstanding awards continue to be governed by the terms and conditions of the PG&E Corporation Long-Term Incentive Program. Stock options have been granted with and without associated dividend equivalents.

On January 1, 2006, the PG&E Corporation 2006 Long-Term Incentive Plan (2006 LTIP) became effective. The LTIP permits the award of various forms of incentive awards including stock options, stock appreciation rights, restricted stock awards, restricted stock units, performance shares, performance units, deferred compensation awards, and other stock-based awards. A maximum of 12 million shares of PG&E Corporation common stock (subject to adjustment for changes in capital structure, stock dividends, or other similar events) have been reserved for use under the 2006 LTIP.

Stock Options

At December 31, 2005, 11,899,059 shares of PG&E Corporation common stock were available for issuance pursuant to awards that were outstanding under the PG&E Corporation Long-Term Incentive Program. No shares were available for grant. As stated above, the 2006 LTIP became effective on January 1, 2006. No options were granted under the 2006 LTIP.

PG&E Corporation

The weighted average grant date fair values of options granted using the Black-Scholes valuation method were $8.51 per share in 2005, $8.70 per share in 2004, and $7.27 per share in 2003. The significant assumptions used in the Black-Scholes valuation method for shares granted in 2005, 2004, and 2003 were:

	2005	2004	2003
Expected stock price volatility	40.6%	45.0%	45.0%
Expected annual dividend payment	$1.20	$1.20	$ –
Risk-free interest rate	3.74%	3.66%	3.46%
Expected life	5.9 years	6.5 years	6.5 years

Stock options issued after January 2003 become exercisable on a cumulative basis at one-fourth each year commencing one year from the date of the grant. Stock options issued before January 2003 become exercisable on a cumulative basis at one-third each year commencing two years from the date of grant. All options expire 10 years and one day after the date of grant. Options outstanding at December 31, 2005 had option prices ranging from $12.50 to $38.82, and a weighted average remaining contractual life of 5.71 years.

The following table summarizes stock option activity for the years ended December 31:

	2005		2004		2003	
	Shares	Weighted Average Option Price	Shares	Weighted Average Option Price	Shares	Weighted Average Option Price
Outstanding at January 1	20,878,558	$22.76	27,416,380	$21.26	31,067,611	$22.22
Granted	1,469,655	33.13	2,450,400	27.24	3,649,902	14.62
Exercised	(10,239,341)	23.69	(8,173,864)	18.39	(3,818,837)	19.15
Cancelled	(209,813)	22.21	(814,358)	21.37	(3,482,296)	25.18
Outstanding at December 31	11,899,059	$23.26	20,878,558	$22.76	27,416,380	$21.26
Exercisable	7,951,520	$22.19	13,981,720	$24.67	16,072,654	$25.34

The following table summarizes information for options outstanding and exercisable at December 31, 2005:

	Outstanding			Exercisable	
Exercise Price Range	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Shares	Weighted Average Exercise Price
$12.50–16.68	4,216,044	$14.66	6.18	3,024,693	$14.68
19.45–28.40	3,792,252	24.18	5.92	2,370,169	22.37
30.50–38.82	3,890,763	31.67	5.00	2,556,658	30.90

Utility

Outstanding stock options to purchase PG&E Corporation common stock held by Utility employees at December 31, 2005 had option prices ranging from $12.63 to $38.82, and a weighted average remaining contractual life of 6.02 years. The following table summarizes the stock option activity for the Utility employees for the years ended December 31:

	2005		2004		2003	
	Shares	Weighted Average Option Price	Shares	Weighted Average Option Price	Shares	Weighted Average Option Price
Outstanding at January 1	11,068,674	$22.58	13,543,182	$21.01	13,300,300	$22.32
Granted[1]	1,067,900	33.15	1,903,238	26.05	2,160,425	14.62
Exercised	(4,666,125)	23.81	(4,146,084)	19.00	(1,310,156)	20.97
Cancelled	(98,688)	28.55	(231,662)	23.40	(607,387)	27.05
Outstanding at December 31	7,371,761	$23.15	11,068,674	$22.58	13,543,182	$21.01
Exercisable	4,513,751	$21.76	6,607,089	$24.94	7,668,908	$25.33

(1) Includes net stock options related to employee transfers to the Utility.

The following table summarizes information for options outstanding and exercisable at December 31, 2005:

	Outstanding			Exercisable	
Exercise Price Range	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Shares	Weighted Average Exercise Price
$12.63–16.68	2,812,301	$14.64	6.19	1,944,534	$14.65
19.81–28.40	2,213,273	24.72	6.35	1,157,730	22.42
30.50–38.82	2,346,187	31.87	5.50	1,411,487	31.00

Restricted Stock

At December 31, 2005, a total of 2,436,630 shares of restricted PG&E Corporation common stock had been awarded to eligible employees of PG&E Corporation and its subsidiaries, of which 1,597,385 shares were granted to Utility employees. PG&E Corporation granted 347,710 shares of restricted common stock during 2005, of which 247,470 shares were granted to Utility employees. At December 31, 2005, 1,399,990 shares of restricted PG&E Corporation common stock were outstanding, of which 958,675 related to Utility employees. The shares were granted with restrictions and are subject to forfeiture unless certain conditions are met.

The restricted shares are held in an escrow account. The shares become available to the employees as the restrictions lapse. For restricted stock granted in 2003, the restrictions on 80% of the shares lapse automatically over a period of four years at the rate of 20% per year. The compensation

expense for these shares remains fixed at the value of the stock at grant date. Restrictions on the remaining 20% of the shares lapse at a rate of 5% per year if PG&E Corporation is in the top quartile of its comparator group as measured by annual total shareholder return for each year ending immediately before each annual lapse date. The compensation expense recognized for these shares is variable, and changes with the common stock's market price. The performance criteria for restricted stock awarded in 2003 was not met during 2005 and 2004. For restricted stock grants awarded in 2005 and 2004, there were no restricted stock shares containing performance criteria and the restrictions lapse ratably over four years.

Compensation expense associated with all the shares is recognized on a quarterly basis, by amortizing the unearned compensation related to that period. Total compensation expense resulting from the restricted stock issuance reflected on PG&E Corporation's Consolidated Statements of Income was approximately $13 million in 2005 and approximately $9 million in 2004, of which approximately $8 million in 2005 and approximately $6 million in 2004 was recognized by the Utility. The total unamortized balance of unearned compensation resulting from the restricted stock issuance reflected on PG&E Corporation's Consolidated Balance Sheets was approximately $22 million at December 31, 2005 and $26 million at December 31, 2004. On January 3, 2006, PG&E Corporation awarded 506,835 shares of restricted stock, of which 355,440 shares were granted to Utility employees.

Performance Shares and Performance Units

Starting in 2004, PG&E Corporation awarded 835,570 performance shares, or phantom stock, to certain officers and employees of PG&E Corporation and its subsidiaries, of which 589,500 were awarded to Utility employees. The performance shares, subject to the achievement of certain performance targets, vest on the third anniversary of the date of grant. The number of performance shares that were outstanding at December 31, 2005 was 803,975, of which 565,706 were related to Utility employees. The amount of compensation expense recognized in 2005 in connection with the issuance of performance shares was approximately $10 million, of which $7 million was recognized by the Utility. On January 3, 2006, PG&E Corporation awarded 506,835 performance shares, of which 355,440 were awarded to Utility employees.

PG&E Corporation has granted performance units to certain officers and employees of PG&E Corporation and its subsidiaries. The performance units, subject to achievement of certain performance targets, vested one-third per year and were settled in cash annually as vesting occurred in each of the three years following the year of grant. As a result of achieving performance criteria, all remaining units vested at December 31, 2004, and PG&E Corporation recognized compensation expense totaling approximately $5 million in 2004, of which $2 million related to the Utility. These amounts were paid in January 2005 to the participating individuals.

PG&E Corporation Supplemental Retirement Savings Plan

The supplemental retirement savings plan provides supplemental retirement alternatives to eligible officers and key employees of PG&E Corporation and its subsidiaries by allowing participants to defer portions of their compensation, including salaries and amounts awarded under various incentive awards and to receive supplemental employer-provided retirement benefits. Under the employee-elected deferral component of the plan, eligible employees may defer all or part of their incentive awards, and 5% to 50% of their salary. Under the supplemental employer-provided retirement benefits component of the plan, eligible employees may receive full credit for employer matching and basic contributions, under the respective defined contribution plan, in excess of limitations set by the Code. A separate non-qualified account is maintained for each eligible employee to track deferred amounts. The account's value is adjusted in accordance with the performance of the investment options selected by the employee. Each employee's account is adjusted on a quarterly basis and the change in value is recorded as additional compensation expense or income in the Consolidated Financial Statements. Total compensation expense recognized by PG&E Corporation and the Utility in connection with the plan amounted to:

(in millions)	PG&E Corporation	Utility
Year ended December 31,		
2005	$3	$1
2004	3	1
2003	7	1

RETENTION PROGRAMS

PG&E Corporation implemented various retention programs in 2001. One of these programs granted key personnel of PG&E Corporation and its subsidiaries with lump-sum cash payments. Another program awarded units of special senior executive retention grants.

These grants provided certain employees with PG&E Corporation with phantom restricted stock units that vested in full on December 31, 2003 upon PG&E Corporation meeting certain performance measures at that date. A total of 3,044,600 phantom stock units were granted under this program. There were no similar grants in 2004. These units were marked to market based on the market price of PG&E Corporation common stock and amortized as a charge to income over a four-year period. As a result of meeting the performance criteria at December 31, 2003, these units fully vested and the remaining compensation expense was recognized in 2003. Total compensation expense recognized in connection with these retention mechanisms, including cash payments and phantom restricted stock units, amounted to:

(in millions)	PG&E Corporation	Utility
Year ended December 31,		
2005	$ –	$ –
2004	–	–
2003	63	38

In January 2004, approximately $84.5 million was paid to participating individuals in the senior executive retention program. There are no payments remaining under either plan.

NOTE 15: THE UTILITY'S EMERGENCE FROM CHAPTER 11

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

The Utility emerged from Chapter 11 when its plan of reorganization became effective on April 12, 2004, or the Effective Date. The plan of reorganization incorporated the terms of the Settlement Agreement approved by the CPUC on December 18, 2003, and entered into among the CPUC, the Utility and PG&E Corporation on December 19, 2003, to resolve the Utility's Chapter 11 proceeding. Although the Utility's operations are no longer subject to the oversight of the bankruptcy court, the bankruptcy court retains jurisdiction to hear and determine disputes arising in connection with the interpretation, implementation or enforcement of (1) the Settlement Agreement, (2) the plan of reorganization, and (3) the bankruptcy court's December 22, 2003 order confirming the plan of reorganization. In addition, the bankruptcy court retains jurisdiction to resolve remaining disputed claims.

In anticipation of its emergence from Chapter 11, the Utility consummated its public offering of $6.7 billion of First Mortgage Bonds on March 23, 2004. Upon the Effective Date, the Utility paid all valid claims, deposited funds into escrow accounts for the payment of disputed claims upon their resolution, reinstated certain obligations, and paid other obligations. The following table summarizes the sources and uses of funds on the Effective Date:

(in millions)	Sources		Uses
First Mortgage Bonds	$ 6,700	Payments to Creditors	$ 8,394
Term Loans	799	Disputed Claims Escrow	1,843
Accounts Receivable Financing Facility	350		
Total Debt Financing	7,849		
Cash Used to Pay Claims	2,388		
Sources of Funds for Claims	10,237	Uses of Funds for Claims	10,237
Reinstated Pollution Control Bond-Related Obligations	814	Reinstated Pollution Control Bond-Related Obligations	814
Reinstated Preferred Stock	421	Reinstated Preferred Stock	421
Cash on Hand	225	Preferred Dividends	93
		Environmental Measures	10
		Transaction Costs	122
Total Sources of Funds	$11,697	Total Uses of Funds	$11,697

In light of the satisfaction of various conditions to the implementation of the plan of reorganization, the accounting probability standard required to be met under SFAS No. 71, in order for the Utility to recognize the regulatory assets provided under the Settlement Agreement, was met as of March 31, 2004. Therefore, the Utility recorded the $2.2 billion, after-tax ($3.7 billion, pre-tax) Settlement Regulatory Asset, and $0.7 billion, after-tax ($1.2 billion, pre-tax), for the Utility retained generation regulatory assets. For a further discussion of these regulatory assets, see Note 3.

At December 31, 2004, the Utility had accrued approximately $2.1 billion for remaining disputed claims. Since December 31, 2004, the Utility has made payments to creditors of approximately $6 million in settlement of disputed claims and, as a result of settlements reached with creditors, has reduced the disputed claims balance by approximately $400 million. The Utility held $1.3 billion in escrow for the payment of the remaining disputed claims as of December 31, 2005. Upon resolution of these claims and under the terms of the Settlement Agreement, any refunds, claim offsets or other credits that the Utility receives from energy suppliers will be returned to customers. With the approval of the bankruptcy court, the Utility has withdrawn certain amounts from the escrow in connection with settlements with certain ISO and PX sellers. As of December 31, 2005, the amount of the accrual was approximately $1.2 billion for remaining net disputed claims, consisting of approximately $1.7 billion of accounts payable-disputed claims primarily payable to the ISO and the Power Exchange, or the PX, offset by an accounts receivable from the ISO and the PX of approximately $0.5 billion.

Two former CPUC commissioners who did not vote to approve the Settlement Agreement filed an appeal of the bankruptcy court's confirmation order with the U.S. District Court for the Northern District of California, or the District Court. On July 15, 2004, the District Court dismissed their appeal. The former commissioners have appealed the District Court's order to the Ninth Circuit. The Ninth Circuit heard oral argument on the appeal on February 13, 2006. It is uncertain when a decision will be issued. PG&E Corporation and the Utility believe the former commissioners' appeal of the confirmation order is without merit and will be rejected.

Under applicable federal precedent, once a plan of reorganization has been "substantially consummated," any pending appeals should be dismissed as moot. If, not withstanding this federal precedent, the bankruptcy court's confirmation order is overturned or modified, PG&E Corporation's and the Utility's financial condition and results of operations, and the Utility's ability to pay dividends or otherwise make distributions to PG&E Corporation, could be materially adversely affected.

NOTE 16: RELATED PARTY AGREEMENTS AND TRANSACTIONS

In accordance with various agreements, the Utility and other subsidiaries provide and receive various services to and from their parent, PG&E Corporation, and among themselves. The Utility and PG&E Corporation exchange administrative and professional services in support of operations. Services provided directly to PG&E Corporation by the Utility are priced either at the fully loaded cost (*i.e.*, direct costs and allocations of overhead costs) or at the higher of fully loaded cost or fair market value, depending on the nature of the services. Services provided directly to the Utility by PG&E Corporation are priced either at the fully loaded cost or at the lower of fully loaded cost or fair market value, depending on the nature of the services. PG&E Corporation also allocates certain other corporate administrative and general costs to the Utility and other subsidiaries using agreed upon allocation factors, including the number of employees, operating expenses excluding fuel purchases, total assets and other cost allocation methodologies. The Utility purchases natural gas transportation services from Gas Transmission Northwest Corporation, or GTNW, formerly known as PG&E Gas Transmission Northwest Corporation. Effective April 1, 2003, the Utility no longer purchases natural gas from NEGT Energy Trading Holdings Corporation, or NEGT ET, formerly known as PG&E Energy Trading Holdings Corporation. Both GTNW and NEGT ET are no longer related parties after the cancellation of PG&E Corporation's equity interest in NEGT on the effective date of its plan of reorganization, October 29, 2004. The Utility sold natural gas transportation capacity and other ancillary services to NEGT ET until NEGT's Chapter 11 proceeding was imminent. These services were priced at either tariff rates or fair market value, depending on the nature of the services provided. As discussed in Note 7, Discontinued Operations, through July 7, 2003, all significant intercompany transactions with NEGT and its subsidiaries were eliminated in consolidation; therefore, no

profit or loss resulted from these transactions. Beginning July 8, 2003, the Utility's transactions with NEGT are no longer eliminated in consolidation.

The Utility's significant related party transactions and related receivable (payable) balances were as follows:

(in millions)	Year ended December 31, 2005	2004	2003	Receivable (Payable) Balance Outstanding at Year ended December 31, 2005	2004
Utility revenues from:					
Administrative services provided to PG&E Corporation	$ 5	$ 8	$ 8	$ 2	$ 1
Natural gas transportation capacity services provided to NEGT ET	–	–	8	–	–
Trade deposit due from GTNW	–	–	3	–	–
Utility employee benefit assets due from PG&E Corporation	–	–	–	23	–
Utility expenses from:					
Administrative services received from PG&E Corporation	$111	$81	$183	$(37)	$(20)
Interest accrued on pre-petition liabilities due to PG&E Corporation	–	2	6	–	–
Administrative services received from NEGT	–	–	2	–	–
Software purchases from NEGT ET	–	–	1	–	–
Natural gas commodity services received from NEGT ET	–	–	10	–	–
Natural gas transportation services received from GTNW	–	43	58	–	–
Trade deposit due to NEGT ET	–	–	(7)	–	–

NOTE 17: COMMITMENTS AND CONTINGENCIES

PG&E Corporation and the Utility have substantial financial commitments and contingencies in connection with agreements entered into supporting the Utility's operating activities. PG&E Corporation has no ongoing financial commitments relating to NEGT's current operating activities.

COMMITMENTS

PG&E Corporation

Other than those related to the Utility and disclosed elsewhere in the Notes to the Consolidated Financial Statements at December 31, 2005, PG&E Corporation did not have any material commitments.

UTILITY

Power Purchase Agreements

Qualifying Facility Power Purchase Agreements. The Utility is required by CPUC decisions to purchase energy and capacity from independent power producers that are qualifying co-generation facilities, or QFs, under the Public Utility Regulatory Policies Act of 1978, or PURPA. To implement PURPA, the CPUC required California investor-owned electric utilities to enter into long-term power purchase agreements with QFs and approved the applicable terms, conditions, prices and eligibility requirements. These agreements require the Utility to pay for energy and capacity. Energy payments are based on the QF's actual electrical output and CPUC-approved energy prices, while capacity payments are based on the QF's total available capacity and contractual capacity commitment. Capacity payments may be adjusted if the QF fails to meet or exceeds performance requirements specified in the applicable power purchase agreement.

As of December 31, 2005, the Utility had agreements with 280 QFs for approximately 4,200 megawatts, or MW, that are in operation. Agreements for approximately 3,900 MW expire at various dates between 2006 and 2028. QF power purchase agreements for approximately 300 MW have no specific expiration dates and will terminate only when the owner of the QF exercises its termination option. The Utility also has power purchase agreements with approximately 60 inoperative QFs. The total of approximately 4,200 MW consists of approximately 2,600 MW from cogeneration projects, 600 MW from wind projects and 1,000 MW from projects with other fuel sources, including biomass, waste-to-energy, geothermal, solar and hydroelectric.

On January 22, 2004, the CPUC ordered the California investor-owned electric utilities to allow owners of QFs with certain power purchase agreements expiring before the end of 2005 to extend these contracts for five years with modified pricing terms. As of December 31, 2005, 21 QFs had entered into such five-year contract extensions, 13 in 2004 and 8 in 2005. QF power purchase agreements accounted for approximately 22% of the Utility's 2005 electricity sources, approximately 23% of the Utility's 2004 electricity sources and approximately 20% of the Utility's 2003 electricity sources. No single QF accounted for more than 5% of the Utility's 2005, 2004 or 2003 electricity sources.

There are proceedings pending at the CPUC that may impact both the amount of payments to QFs and the number of QFs holding power purchase agreements with the Utility. The CPUC will address whether certain payments for short-term power deliveries required by the power purchase agreements comply with the pricing requirements of the PURPA. The CPUC is also considering whether to require the California investor-owned electric utilities to enter into new power purchase agreements with existing QFs with expiring power purchase agreements and with newly-constructed QFs. PG&E Corporation and the Utility are unable to predict the outcome of these proceedings.

In a proceeding pending at the CPUC, the Utility has requested refunds in excess of $500 million for overpayments from June 2000 through March 2001 that were made to QFs pursuant to CPUC orders at approved rates. The net after-tax amount of any QFs refunds, which the Utility actually realizes in cash, claim offsets or other credits, would be credited to customers. PG&E Corporation and the Utility are unable to predict the outcome of this proceeding.

Irrigation Districts and Water Agencies. The Utility has contracts with various irrigation districts and water agencies to purchase hydroelectric power. Under these contracts, the Utility must make specified semi-annual minimum payments based on the irrigation districts' and water agencies' debt service requirements, regardless of 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 2005 to 2031. The Utility's irrigation district and water agency contracts accounted for approximately 5% of the Utility's 2005 electricity sources, approximately 5% of the Utility's 2004 electricity sources and approximately 5% of the Utility's 2003 electricity sources.

Other Power Purchase Agreements

Electricity Purchases to Satisfy the Net Open Position. In 2005, the Utility continued buying electricity to meet its net open position, which is the portion of the demand of a utility's customers, plus applicable reserve margins, not satisfied from that utility's own generation facilities and existing electricity contracts. During 2005, more than 9,000 Gigawatt hours, or GWh, of energy was bought or sold in the wholesale market to manage the 2005 net open position. Contracts entered into in 2005 had both terms of less than one year, and multi-year terms. In 2005, the Utility both submitted and requested bids in competitive solicitations to meet intermediate and long-term needs and anticipates procuring electricity under contracts with multi-year terms beginning in 2006 or later.

Renewable Energy Requirement. California law requires that beginning in 2003, each California retail seller of electricity, except for municipal utilities, increase its purchases of renewable energy (such as biomass, wind, solar and geothermal energy) by at least 1% of its retail sales per year, the annual procurement target, so that the amount of electricity purchased from renewable resources equals at least 20% of its total retail sales by the end of 2017. In January 2005, the California Senate introduced a bill proposing to require the goal to be met by the end of 2010 instead of 2017. The CPUC also has suggested that the 20% goal be met by 2010 and a 33% goal be met by 2020. The Utility estimates that the accelerated goal would require the Utility to increase the amount of its annual renewable energy purchases to approximately 800-900 GWh. During 2005, the Utility entered into several new renewable power purchase contracts that will help the Utility meet its goals.

Annual Receipts and Payments. The payments made under qualifying facility, irrigation district, water agency and bilateral agreements during 2003 through 2005 were as follows:

(in millions)	2005	2004	2003
Qualifying facility energy payments	$954	$1,002	$994
Qualifying facility capacity payments	486	487	499
Irrigation district and water agency payments	54	61	62
Other power purchase agreement payments	774	834	513

At December 31, 2005, the undiscounted future expected power purchase agreement payments were as follows:

	Qualifying Facility		Irrigation District & Water Agency		Other		
(in millions)	Energy	Capacity	Operations & Maintenance	Debt Service	Energy	Capacity	Total
2006	$ 1,537	$ 504	$ 53	$ 26	$ 55	$ 63	$ 2,238
2007	1,892	483	51	26	54	65	2,571
2008	1,701	473	34	26	48	33	2,315
2009	1,396	433	32	24	55	5	1,945
2010	1,145	397	33	22	42	1	1,640
Thereafter	7,666	3,067	151	95	587	3	11,569
Total	$15,337	$5,357	$354	$219	$841	$170	$22,278

Natural Gas Supply and Transportation Commitments

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

At December 31, 2005, the Utility's obligations for natural gas purchases and gas transportation services were as follows:

(in millions)	
2006	$1,447
2007	141
2008	13
2009	9
2010	4
Thereafter	—
Total	$1,614

Payments for natural gas purchases and gas transportation services amounted to approximately $2.5 billion in 2005, $1.8 billion in 2004 and $1.5 billion in 2003.

During the fourth quarter of 2005, the Utility accepted PG&E Corporation's reassignment of certain Canadian natural gas pipeline firm transportation contracts effective November 1, 2007 through October 31, 2023, the remaining term of the contracts' duration. The firm quantity under the contracts is approximately 50 million cubic feet per day and the Utility and PG&E Corporation have estimated annual reservation charges will range between approximately $8 million and $10 million. During the term of the contracts, the applicable reservation charges will equal the full tariff rates set by regulatory authorities in Canada and the United States, as applicable. The Utility and PG&E Corporation are unable to predict the utilization of these contracts, which will depend on market prices, customer demand and approval of cost recovery by the CPUC, among other factors.

Nuclear Fuel Agreements

The Utility has entered purchase agreements for nuclear fuel. These agreements have terms ranging from three to six years and are intended to ensure long-term fuel supply. A total of six new contracts were executed in 2005 for deliveries in 2005 to 2009. One existing services contract was extended for two additional years. Three contracts for

deliveries in 2006 to 2010 and one contract for deliveries in 2010 to 2015 are under negotiation. In most cases, the Utility's nuclear fuel contracts are requirements-based. The Utility relies on well-established international producers of nuclear fuel in order to diversify its sources and provide security of supply. Pricing terms also are diversified, ranging from fixed prices to market-based prices to base prices that are escalated using published indices.

At December 31, 2005, the undiscounted obligations under nuclear fuel agreements were as follows:

(in millions)	
2006	$104
2007	60
2008	53
2009	42
2010	23
Thereafter	13
Total	$295

Payments for nuclear fuel amounted to approximately $65 million in 2005, $119 million in 2004 and $57 million in 2003.

Reliability Must Run Agreements

The ISO has entered into reliability must run, or RMR, agreements with various power plant owners, including the Utility, that require designated units in certain power plants, known as RMR units, to remain available to generate electricity upon the ISO's demand when needed for local transmission system reliability. As a participating transmission owner under the Transmission Control Agreement, the Utility is responsible for the ISO's costs paid under RMR agreements to power plant owners within or adjacent to the Utility's service territory. The Utility's share of the ISO's reliability service costs in 2005 was approximately $217 million. Under the Utility's transmission owner tariff, the Utility recovers the costs, without mark-up or service fees. The Utility also received approximately $59 million in 2005 under the RMR agreements the Utility entered into with the ISO for the Utility's units that have been designated as RMR units. The Utility tracks these costs in the reliability services balancing account. Periodically, the Utility's electricity transmission rates are adjusted to refund over-collections to the Utility's customers or to collect any under-collections from customers.

In November 2001, the Utility and other interested California parties filed a complaint at the FERC against RMR owners other than the Utility, alleging that certain rates under those owners' RMR agreements with the ISO were unlawfully high and proposing that the FERC apply a ratemaking methodology to these other RMR agreements that would significantly reduce those rates. The FERC dismissed the complaint in 2005. In September 2005, the Utility and other interested California parties filed a petition for review of the FERC's decision with the United States Court of Appeals for the District of Columbia Circuit. If the appeal is successful and the FERC applies the revised ratemaking methodology, the Utility may be able to obtain a refund of RMR charges of approximately $50 million that would be credited to the Utility's electricity customers. PG&E Corporation and the Utility are unable to predict the outcome of this matter.

The Utility estimates that it could be obligated to pay the ISO approximately $330 million in reliability service costs in 2006. Of this amount, the Utility estimates that it would receive approximately $36 million under its RMR agreements during 2006.

Advanced Metering Infrastructure

The Utility has signed vendor contracts related to deployment of automated meter reading technology, referred to as Advanced Metering Infrastructure, or AMI, of approximately $900 million in total value. Each of these AMI contracts contains termination clauses that would allow cancellation by the Utility, including in the event CPUC authority is not granted to go forward with AMI. Three of the five contracts contain cancellation penalties which are capped at approximately $14 million before deployment and could exceed that amount post-deployment. In the event of project cancellation, the Utility may submit the contract cancellation penalties for cost recovery through existing CPUC ratemaking vehicles, or through additional cost filings.

Other Commitments and Operating Leases

The Utility has other commitments relating to operating leases, capital infusion agreements, equipment replacements, the self-generation incentive program exchange agreements, energy efficiency programs and telecommunication contracts. At December 31, 2005, the future minimum payments related to other commitments were as follows:

(in millions)	
2006	$146
2007	42
2008	14
2009	6
2010	6
Thereafter	12
Total	$226

Payments for other commitments amounted to approximately $146 million in 2005, $111 million in 2004 and $74 million in 2003.

CONTINGENCIES

PG&E Corporation

PG&E Corporation retains a guarantee related to certain NEGT indemnity obligations issued to the purchaser of an NEGT subsidiary company during 2000, up to $150 million. The underlying indemnity obligations of NEGT have expired and PG&E Corporation's sole remaining exposure relates to the potential environmental obligations that were known to NEGT at the time of the sale, but not disclosed to the purchaser. PG&E Corporation has never received any claims nor does it consider it probable any claims will occur under the guarantee. Accordingly, PG&E Corporation has made no provision for this guarantee at December 31, 2005.

PG&E Corporation also retains a guarantee of the Utility's underlying obligation to pay workers' compensation claims. As of December 31, 2005, the actuarially determined workers' compensation liability was approximately $210.7 million.

UTILITY

PX Block-Forward Contracts

In February 2001, during the energy crisis, the California Governor seized all of the Utility's contracts for the forward delivery of power in the PX market, otherwise known as "block forward contracts," for the benefit of the state under California's Emergency Services Act. These block-forward contracts had an estimated unrealized value of up to $243 million at the time the state of California seized them. The Utility, the PX, and some of the PX market participants have filed competing claims in state court against the state of California to recover the value of these seized contracts. The state of California disputes the plaintiffs' rights to recover the value of the contracts and also disputes plaintiffs' contentions that the contracts had any value beyond the price at which the block forward transactions were executed. This state court litigation is pending. Although the Utility has recorded a receivable of approximately $243 million relating to the estimated value of the contracts at the time of seizure, the Utility also has established a reserve of $243 million for these contracts. If the Utility ultimately prevails, it would record income in the amount of any recovery. PG&E Corporation and the Utility are unable to predict the outcome of this litigation or the amount of any potential recovery.

California Energy Crisis Proceedings

FERC Proceedings

Various entities, including the Utility and the state of California are seeking refunds from energy suppliers in the California ISO and PX markets for electricity overcharges on behalf of California electricity purchasers for the period May 2000 to June 2001 through regulatory and judicial proceedings. At the FERC, the Refund Proceeding commenced on August 2, 2000 when a complaint was filed against all suppliers in the ISO and PX markets.

In March 2003, the FERC accepted a judge's initial decision that power suppliers overcharged the utilities, the state of California and other buyers approximately $1.8 billion from October 2, 2000 to June 20, 2001 but modified the refund methodology to include use of a new natural gas price methodology and indicated sellers could file to reduce refunds by any higher actual natural gas costs. The ISO received the audited fuel cost in November 2005. The FERC also allowed sellers to demonstrate that refunds would result in sales revenue below their costs. The FERC has not yet issued decisions on these filings.

The FERC directed the ISO and the PX (which operates solely to reconcile remaining refund amounts owed) to make compliance filings establishing refund amounts. The ISO has recently indicated that it plans to make its compliance filing in the first quarter of 2006, with the PX to follow. However, the ISO's filing may be delayed until the FERC issues final rules on supplier claims for recovery of certain costs. On January 26, 2006 FERC issued an order rejecting some cost filings and directing adjustments to cost filings by other sellers, with compliance filings due in 15 days. The final refunds will not be determined until the FERC issues a final order after the ISO and PX compliance filings and the resolution of appeals.

Parties have appealed the applicability and scope of the FERC's refund methodology. On September 6, 2005, the Ninth Circuit issued a partial decision finding that the FERC did not have the authority to order governmental and municipal utilities to provide refunds. This decision is subject to rehearing or further appellate review. Following the September 6, 2005 ruling by the Ninth Circuit that the FERC could not order refunds by municipal and governmental entities, but that contractual remedies might be available, the California utilities and the Electricity Oversight Board filed notices of claim against 21 such entities on December 5, 2005. A response is required by the cities and governmental entities within 60 days, following which litigation may be instituted. Claims involving these municipal and governmental entities may be filed by the Utility for $150 million or more.

A further Ninth Circuit decision on the extent of the FERC's power to order refunds from other sellers is still pending. In light of the pending FERC and appellate court decisions relating to cost filings, gas and emissions recovery and allocation, as well as the scope of the FERC's refund authority, there may continue to be adjustments in refund amounts included in prior settlements as well as FERC ordered refunds.

The Utility recorded approximately $1.8 billion of claims filed by various electricity generators in its Chapter 11 proceeding as disputed claims. This amount is subject to a pre-petition offset of approximately $200 million, reducing the net liability recorded to approximately $1.6 billion. Under a bankruptcy court order, the aggregate allowable amount of unpaid PX and generator claims was limited to approximately $1.6 billion. The Utility currently estimates that the claims would have been reduced to approximately $1.0 billion based on the refund methodology recommended in the FERC administrative law judge's initial decision. However, these estimates may change based upon the future regulatory and judicial decisions described above.

The Utility has entered into settlements with various power suppliers resolving certain disputed claims and the Utility's refund claims against these power suppliers. The Utility has recorded approximately $310 million under these settlements as a reduction to the after-tax portion of the Settlement Regulatory Asset that was refinanced through the issuance of the first series of ERBs in February 2005. Approximately $330 million of the energy supplier refunds that the Utility received between the issuance of the first and second series of ERBs were used to reduce the size of the second series of ERBs. The Utility credited an additional $270 million under these settlements to the Energy Recovery Bond Balancing Account, or ERBBA, offset by net interest costs of approximately $95 million related to net disputed claims. As indicated previously, a number of pending FERC and appellate decisions could affect the final amounts actually received by the Utility under the settlement agreements. Amounts received by the Utility under future settlements with energy suppliers will be credited to customers as a credit to the ERBBA, except for those related to certain wholesale power purchases.

Enron Settlement

On August 24, 2005, the Utility, along with the Attorney General of the State of California, the DWR, Southern California Edison, San Diego Gas & Electric Company, the California Electric Oversight Board and the CPUC (collectively, the California Parties), along with the Attorney Generals of the States of Oregon and Washington, and the FERC's Office of Market Oversight and Investigations (collectively, the Other Parties) entered into a definitive agreement with Enron Corporation and various of its subsidiaries, or Enron, to satisfy Enron's liabilities in the Refund Proceeding. The FERC approved the settlement on November 15, 2005.

The settlement provides that Enron would pay $47 million in cash to the California Parties and Other Parties, and allow them an unsecured claim of $875 million in the bankruptcy proceeding of Enron Power Marketing, Inc., a subsidiary through which Enron conducted its power marketing operations in California, to settle electric and gas market overcharges. Of these amounts, the Utility expects to receive approximately $12 million in cash, over time, which includes approximately $4 million for reimbursement of attorney fees and other litigation costs, and approximately $346 million of the unsecured claim. The actual value of the bankruptcy claim is uncertain, and may include stock in Portland General Electric Co. to be issued in April 2006. The final Enron amount would not be determined until the conclusion of the bankruptcy case unless liquidated earlier in a secondary market for such claims.

Reliant Settlement

On August 12, 2005, the Utility, along with the Attorneys General of the States of Oregon and Washington, the DWR, the FERC's Office of Market Oversight and Investigations, Southern California Edison and San Diego Gas & Electric Company entered into a memorandum of understanding

with Reliant Energy, Inc. and various of its subsidiaries, or Reliant, to resolve claims against Reliant for gas and electric market manipulation and overcharges during the California energy crisis in 2000 and 2001. The definitive agreement was subsequently executed and submitted to the FERC for approval on October 14, 2005. The settlement was approved by the FERC and became effective on December 22, 2005.

The agreement provides that Reliant will assign to the California Parties approximately $300 million of its receivables from the California ISO or PX and related interest of approximately $10 million. In addition, Reliant will provide the California Parties approximately $131 million in cash. The allocation of these considerations among the California Parties remains subject to final negotiation and agreement. The Utility recognized approximately $105 million of its share of the settlement proceeds in 2005 as a reduction in the Utility's payable to the PX. The remaining refunds to be provided under the settlement agreement have not yet been recorded as several conditions, which are expected in 2006, have not yet occurred.

Mirant Settlement

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

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

The second part of the settlement is between the Utility and Mirant and is designed to settle claims that Mirant overcharged the Utility under Mirant's RMR contracts and other disputes. Under the settlement agreement, Mirant has agreed to provide $43 million to the Utility for certain RMR costs and $20 million for sulfur dioxide emission allowances, or SO2 allowances. In addition, Mirant agreed to transfer to the Utility the equipment, permits and contracts for the construction of Contra Costa Unit 8, a modern 530 MW electric generating facility Mirant started to build, but never completed. On June 10, 2005, the Utility and Mirant completed negotiations of an Asset Transfer Agreement, which provides the terms and conditions under which the Contra Costa 8 equipment, permits, and contracts would be transferred to the Utility and development and construction of the plant would be completed. On June 17, 2005, the Utility filed an application with the CPUC requesting approval of the Asset Transfer Agreement and cost-of-service funding to complete the $310 million construction of the facility, and funding to operate it for up to three years. A final decision by the CPUC is expected in March or April 2006. If the Utility and Mirant do not receive the necessary approvals, including CPUC authorization, the Utility will be paid at least $70 million from an escrow account funded by Mirant in lieu of transferring the assets. The settlement agreement also includes a contract that gives the Utility the right, from 2006 through 2012, to dispatch power from certain RMR units owned by Mirant subsidiaries, subject to continued RMR status, when the facilities are not needed by the ISO to meet local reliability needs. In addition, Mirant has withdrawn the claim it filed in the Utility's bankruptcy proceeding of approximately $20 million. On January 6, 2006, the Utility received consideration of approximately $133 million, comprised of cash and new Mirant stock, which provided for the above mentioned $43 million for certain RMR costs claims and $20 million for SO2 allowances, as well as $70 million to fund the escrow account.

The settlement agreement became effective on April 15, 2005, after all regulatory and other approvals required by the settlement agreement were obtained. As of December 31, 2005, the Utility has recorded a receivable and a corresponding regulatory liability of approximately $133 million, which includes the $70 million discussed above relating to the

transfer of the Contra Costa 8 assets, representing the expected value to be received in connection with the Mirant settlement agreement.

Scheduling Coordinator Costs

Before the ISO commenced operation in 1998, the Utility had entered into several wholesale electric transmission contracts with various governmental entities. After the ISO began operations, the Utility served as the scheduling coordinator, or SC, with the ISO for these existing wholesale transmission customers. The ISO billed the Utility for providing certain services associated with this scheduling. These ISO charges are referred to as "SC costs." The SC costs were historically tracked in the transmission revenue balancing account, or TRBA, in order to recover the SC costs from retail and new wholesale transmission customers, or TO Tariff customers. In 1999, a FERC administrative law judge ruled that the Utility could not recover the SC costs through the TRBA and instead should seek to recover them from the existing wholesale transmission customers.

In January 2000, the FERC accepted a filing by the Utility to establish the Scheduling Coordinator Services, or SCS Tariff, to serve as an alternative mechanism for recovery of the SC costs from existing wholesale transmission customers if the Utility was ultimately unable to recover these costs in the TRBA.

In August 2002, the FERC ruled that the Utility should refund to TO Tariff customers the SC costs that the Utility collected from them through the TRBA. In December 2002, the Utility appealed the FERC's decision in the United States Court of Appeals for the District of Columbia Circuit, or D.C. Circuit. In the absence of an order from the FERC granting recovery of these costs in the TRBA, the Utility made accounting entries in September 2002 to remove the SC costs from the TRBA and reflect the SC costs as accounts receivable under the SCS Tariff.

In October 2004, the FERC issued an order finding that the Utility could recover the SC costs from the existing wholesale customers. The Utility began billing the existing wholesale customers in June 2004 for SC charges retroactive to March 31, 1998 based on the FERC's initial decision issued in May 2004. Before the FERC hearing to address the allocation of costs to SC customers began in May 2005, the Utility settled with six of these eight wholesale transmission customers. The hearing with the remaining two wholesale customers lasted until June 2005.

In July 2005, the D.C. Circuit issued an order finding that the FERC had erred in its decision that the Utility could not recover the SC costs through the TRBA. The D.C. Circuit held that the Utility was not barred from recovering the SC costs through the TRBA, as had been concluded in August 2002. The D.C. Circuit remanded the matter to the FERC for further action.

On December 20, 2005, the FERC issued an order on remand concluding that the Utility should recover the SC costs through the TRBA mechanism or through bilateral agreements with the existing wholesale transmission customers. The FERC also held that the ISO tariff does not specify recovery of the SC costs through any other rate recovery mechanism and terminated the SCS Tariff proceeding. The FERC also terminated the sub-dockets in the TRBA proceeding under which the Utility was required to provide a refund to TO Tariff customers for the SC costs it had previously tried to recover. For the period April 1998 through December 31, 2005, the Utility was invoiced approximately $135 million by the ISO for SC costs.

On January 19, 2006, the Utility submitted a request for clarification or, alternatively, for rehearing to seek clarification of the December 2005 order. In particular, the Utility asked that the FERC clarify that the Utility can recover through the TRBA all of the costs it incurred as an SC or, alternatively on rehearing, reverse its decision to terminate the SCS Tariff proceeding. The Utility cannot predict what the outcome of this request will be; however, to the extent the Utility can recover all costs it incurred as an SC through the TRBA, the outcome is not expected to have a material adverse effect on its results of operations or financial condition.

Nuclear Insurance

The Utility has several types of nuclear insurance for Diablo Canyon and Humboldt Bay Unit 3. The Utility has insurance coverage for property damages and business interruption losses as a member of Nuclear Electric Insurance Limited, or NEIL. NEIL is a mutual insurer owned by utilities with nuclear facilities. NEIL provides property damage and business interruption coverage of up to $3.24 billion per incident for Diablo Canyon. In addition, NEIL provides $131 million of property damage insurance for Humbolt 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 $43.6 million per one-year policy term.

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

Under the Price-Anderson Act, public liability claims from a nuclear incident are limited to $10.8 billion. As required by the Price-Anderson Act, the Utility purchased the maximum available public liability insurance of $300 million for Diablo Canyon. The balance of the $10.8 billion of liability protection is covered by a loss-sharing program among utilities owning nuclear reactors. Under the Price-Anderson Act, owner participation in this loss-sharing program is required for all owners of nuclear reactors that are licensed to operate, designed for the production of electrical energy, and have a rated capacity of 100 MW or higher. If a nuclear incident results in costs in excess of $300 million, then the Utility may be responsible for up to $100.6 million per reactor, with payments in each year limited to a maximum of $15 million per incident until the Utility has fully paid its share of the liability. Since Diablo Canyon has two nuclear reactors each with a rated capacity of over 100 MW, the Utility may be assessed up to $201.2 million per incident, with payments in each year limited to a maximum of $30 million per incident. Under the Energy Policy Act of 2005, the Price-Anderson Act was extended through December 31, 2025. Both the maximum assessment per reactor and the maximum yearly assessment will be adjusted for inflation beginning August 31, 2008.

In addition, the Utility has $53.3 million of liability insurance for the retired nuclear generating unit at Humboldt Bay power plant and has a $500 million indemnification from the NRC, for public liability arising from nuclear incidents covering liabilities in excess of the $53.3 million of liability insurance.

California Department of Water Resources Contracts

Electricity from the DWR contracts to the Utility provided approximately 27% of the electricity delivered to the Utility's customers for the year ended December 31, 2005. The DWR purchased the electricity under contracts with various generators. The Utility, as an agent, is responsible for administration and dispatch of the DWR's electricity procurement contracts allocated to the Utility for purposes of meeting a portion of the Utility's net open position. The Utility's net open position is the portion of the Utility's customers' demand, plus the applicable reserve margins, that is not satisfied from the Utility's own generation facilities and existing electricity contracts. The DWR remains legally and financially responsible for its electricity procurement contracts. The Utility acts as a billing and collection agent of the DWR's revenue requirements from the Utility's customers.

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

The DWR has stated publicly in the past that it intends to transfer full legal title to, and responsibility for, the DWR power purchase contracts to the California investor-owned electric utilities as soon as possible. However, the DWR power purchase contracts cannot be transferred to the Utility without the consent of the CPUC. The Settlement Agreement provides that the CPUC will not require the Utility to accept an assignment of, or to assume legal or financial responsibility for, the DWR power purchase contracts unless each of the following conditions has been met:

- After assumption, the Utility's issuer rating by Moody's will be no less than A2 and the Utility's long-term issuer credit rating by S&P will be no less than A;
- The CPUC first makes a finding that the DWR power purchase contracts to be assumed are just and reasonable; and
- The CPUC has acted to ensure that the Utility will receive full and timely recovery in its retail electricity rates of all costs associated with the DWR power purchase contracts to be assumed without further review.

Defined Benefit Pension Plan Contribution

The CPUC has recently issued a decision to allow the Utility to file a rate increase application to recover the revenue requirement associated with the portion of a pension contribution in 2006 attributable to the Utility's distribution and generation businesses. The decision also authorized the Utility to make that revenue requirement effective in rates beginning January 1, 2006, subject to refund depending on the outcome of the application. As a result of the CPUC decision, on December 20, 2005, the Utility filed an application requesting a revenue requirement increase of $155 million for the pension contribution in 2006, and on January 1, 2006, electric and gas rate increases to recover the amount of $155 million became effective, subject to refund. The Utility is unable to predict the outcome of the application to the CPUC, or the impact it will have on its financial condition or results of operations.

Underground Electric Facilities

At December 31, 2005, the Utility is committed to spending approximately $346 million for the conversion of existing overhead electric facilities to underground electric facilities. Although the majority of these costs are expected to be spent over the next five years, the timing of the work is dependent upon a number of factors, including the schedules of the respective cities and counties and telephone utilities involved. The Utility expects to spend approximately $50 to $55 million each year in connection with these projects for the next five years.

Supplier Concentrations

Calpine Corporation and certain of its subsidiaries that have filed Chapter 11 petitions, or Calpine, have sought to reject certain power purchase contracts under which they provide approximately 13% of the electricity needed by the Utility's customers. A federal district court recently held that it lacks jurisdiction to authorize Calpine to reject the contracts, finding that the FERC has exclusive jurisdiction with respect to the contracts. Calpine has appealed that decision. As a result of this uncertainty, the Utility is subject to system reliability risks if Calpine fails to operate in its Northern California power plants. The Utility is working with the ISO, the CPUC and DWR to ensure that a coordinated effort is in place to avoid facility shut-downs. If Calpine fails to perform under the contracts, the Utility will be required to procure electricity at current market prices which may be higher than the costs the Utility would otherwise pay under the Calpine contracts. The Utility also may be required to procure natural gas for Calpine's RMR power plants which would likely cause the Utility to incur additional costs. It is expected that these costs would be recovered from customers.

ENVIRONMENTAL MATTERS

The Utility may be required to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party under the Comprehensive Environmental Response Compensation and Liability Act of 1980 as amended, and similar state environmental laws. These sites include former manufactured gas plant sites, power plant sites, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous materials. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if the Utility did not deposit those substances on the site.

The cost of environmental remediation is difficult to estimate. The Utility records an environmental remediation liability when site assessments indicate remediation is probable and it can estimate a range of reasonably likely clean-up costs. The Utility reviews its remediation liability on a quarterly basis for each site where it may be exposed to remediation responsibilities. The liability is an estimate of costs for site investigations, remediation, operations and maintenance, monitoring and site closure using current technology, enacted laws and regulations, experience gained at similar sites, and an assessment of the probable level of involvement and financial condition of other potentially responsible parties. Unless there is a better estimate within this range of possible costs, the Utility records the costs at the lower end of this range. It is reasonably possible that a change in these estimates may occur in the near term due to uncertainty concerning the Utility's responsibility, the complexity of environmental laws and regulations, and the selection of compliance alternatives. The Utility estimates the upper end of the cost range using reasonably possible outcomes least favorable to the Utility.

The Utility had an undiscounted environmental remediation liability of approximately $469 million at December 31, 2005, and approximately $327 million at December 31, 2004. During the year ended December 31, 2005, the liability increased by approximately $142 million. This net increase reflects a $131 million increase attributable to a revised remediation estimate for the Topock gas compressor station and a $24 million increase attributable to a revised

remediation estimate for the Hinkley gas compressor station. These increases, in addition to other increases in liability, were offset by remediation payments. The $469 million accrued at December 31, 2005, includes approximately $193 million for remediation at these gas compressor sites, approximately $100 million related to the pre-closing remediation liability associated with divested generation facilities, and approximately $176 million related to remediation costs for those generation facilities that the Utility still owns, gas gathering sites, third-party disposal sites, and manufactured gas plant sites that either are owned by the Utility or are the subject of remediation orders by environmental agencies or claims by the current owners of the former manufactured gas plant sites. Of the approximately $469 million environmental remediation liability, approximately $141 million has been included in prior rate setting proceedings and the Utility expects that an additional approximately $259 million will be allowable for inclusion in future rates in accordance with the ratemaking mechanism described above. The Utility also recovers its costs from insurance carriers and from other third parties whenever possible. Any amounts collected in excess of the Utility's ultimate obligations may be subject to refund to customers.

The Utility's undiscounted future costs could increase to as much as $680 million if the other potentially responsible parties are not financially able to contribute to these costs, or if the extent of contamination or necessary remediation is greater than anticipated. The amount of approximately $680 million does not include an estimate for the cost of remediation at known sites owned or operated in the past by the Utility's predecessor corporations for which the Utility has not been able to determine whether a liability exists.

LEGAL MATTERS

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

In accordance with SFAS No. 5, "Accounting for Contingencies," PG&E Corporation and the Utility make a provision for a liability when it is both probable that a liability has been incurred and the amount of the loss can be reasonably estimated. These provisions are reviewed quarterly and adjusted to reflect the impacts of negotiations, settlements and payments, rulings, advice of legal counsel and other information and events pertaining to a particular case. In assessing such contingencies, PG&E Corporation's and the Utility's policy is to exclude anticipated legal costs.

The accrued liability for legal matters is included in PG&E Corporation's and the Utility's other noncurrent liabilities in the Consolidated Balance Sheets, and totaled approximately $388 million at December 31, 2005 and $220 million at December 31, 2004.

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

Chromium Litigation

There are 12 civil suits pending against the Utility in the Superior Court for the County of Los Angeles in which plaintiffs allege that exposure to chromium at or near the Utility's compressor stations at Hinkley and Kettleman, California, and the area of California near Topock, Arizona, caused personal injuries, wrongful deaths, or other injuries, referred to as the Chromium Litigation. One of these suits also names PG&E Corporation as a defendant. There are currently about 1,200 plaintiffs in the Chromium Litigation who seek compensatory damages, more than 1,000 of whom are also seeking punitive damages. Although the plaintiffs' complaints in the Chromium Litigation do not state the amount of compensatory or punitive damages claimed, approximately 1,000 of the current plaintiffs filed claims in the Utility's Chapter 11 case requesting compensatory damages in an approximate aggregate amount of $500 million and others filed claims for an "unknown amount." (The Utility's exit from Chapter 11 in April 2004 did not affect the plaintiffs' claims for compensatory and punitive damages).

On February 3, 2006, the Utility entered into a settlement agreement with attorneys for approximately 1,100 plaintiffs in the Chromium Litigation. The Utility has agreed to pay $295 million to the settling plaintiffs. The Utility will deposit the settlement amount into escrow on April 21, 2006. The settling plaintiffs are required to execute general releases in favor of the Utility, PG&E Corporation, its officers, directors, employees, and other affiliates, as to any and all claims asserted or which could have been asserted in the Chromium Litigation. After receipt of releases from at least 90% of the

settling plaintiffs, executed requests for dismissals with prejudice of the settled cases, and documentation evidencing the Superior Court's approval of the compromises or settlements with the settling plaintiffs who are minors, payments will be released from escrow to plaintiffs' attorneys for the plaintiffs who have submitted executed releases. If 90% of the settling plaintiffs do not execute releases by September 15, 2006, including a release signed by each of the eighteen plaintiffs scheduled to participate in the first trial, the Utility may, at its option, terminate the settlement agreement. In order to obtain 100% of the settlement funds from escrow, plaintiffs' attorneys must submit releases from or on behalf of 100% of the settling plaintiffs.

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

PG&E Corporation's and the Utility's financial results for the year ended December 31, 2005, includes an accrual of approximately $314 million to reflect both the settlement and the remaining unresolved claims, an increase of $154 million over the $160 million previously accrued. PG&E Corporation and the Utility do not expect that the outcome with respect to the remaining unresolved claims will have a material adverse effect on their financial condition or results of operations.

Pending CPUC Investigation

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

On February 3, 2006, the CPUC's Consumer Protection and Safety Division, or CPSD, and TURN submitted their reports to the CPUC concluding that the Utility violated applicable tariffs related to delayed and estimated bills. The CPSD recommends that the Utility refund to customers $117 million, plus interest at the three-month commercial paper interest rate, that allegedly was collected in violation of the tariffs. TURN recommends that the Utility refund to customers $53 million, plus interest at the three-month commercial paper interest rate, that allegedly was collected in violation of the tariffs. The two refunds are not additive. The CPSD also recommends that the Utility pay fines of $6.75 million, while TURN recommends fines in the form of a $1 million contribution to REACH (Relief for Energy Assistance through Community Help). Both the CPSD and TURN recommend that refunds and fines be funded by shareholders. In addition, the CPSD also seeks to require the Utility to recalculate all estimated bills from 2000 to the present if the Utility did not calculate the average daily usage over the period of estimation, and to credit customers for any alleged overcharges. The Utility is uncertain whether the re-calculation would result in any additional alleged overcharges.

If the CPUC finds that the Utility violated applicable tariffs or the CPUC's orders or rules, the CPUC may seek to order the Utility to refund any amounts collected in violation of tariffs, plus interest, to customers who paid such amounts. In addition, if the CPUC finds that the Utility violated applicable tariffs or the CPUC's orders or rules, the CPUC may seek to impose penalties on the Utility ranging from $500 to $20,000 for each separate violation.

PG&E Corporation and the Utility are unable to predict the outcome of this matter. In light of this uncertainty, the outcome could have a material adverse effect on PG&E Corporation's or the Utility's financial condition or results of operations.

QUARTERLY CONSOLIDATED FINANCIAL DATA (UNAUDITED)

(in millions, except per share amounts)	Quarter ended December 31	September 30	June 30	March 31
2005[1]				
PG&E CORPORATION				
Operating revenues	$3,732	$2,804	$2,498	$2,669
Operating income	414	515	540	501
Income from continuing operations	180	239	267	218
Net income	180	252	267	218
Earnings per common share from continuing operations, basic	0.49	0.63	0.70	0.55
Earnings per common share from continuing operations, diluted	0.49	0.62	0.70	0.54
Net income per common share, basic	0.49	0.66	0.70	0.55
Net income per common share, diluted	0.49	0.65	0.70	0.54
Common stock price per share:				
High	40.10	39.64	37.91	36.18
Low	34.54	35.60	33.78	31.83
UTILITY				
Operating revenues	$3,733	$2,804	$2,498	$2,669
Operating income	418	517	540	495
Net income	187	248	276	223
Income available for common stock	183	244	272	219
2004[1]				
PG&E CORPORATION				
Operating revenues	$2,986	$2,623	$2,749	$2,722
Operating income[2][3]	584	509	672	5,353
Income from continuing operations	187	228	372	3,033
Net income[4]	871	228	372	3,033
Earnings per common share from continuing operations, basic	0.45	0.55	0.89	7.36
Earnings per common share from continuing operations, diluted	0.44	0.53	0.88	7.15
Net income per common share, basic	2.07	0.55	0.89	7.36
Net income per common share, diluted	2.04	0.53	0.88	7.15
Common stock price per share:				
High	34.46	30.40	30.32	29.35
Low	30.32	27.50	25.90	26.47
UTILITY				
Operating revenues	$2,986	$2,623	$2,749	$2,722
Operating income[2][3]	584	516	682	5,362
Net income	248	248	412	3,074
Income available for common stock	243	244	408	3,066

(1) The operating results of NEGT through July 7, 2003 have been excluded from continuing operations and reported as discontinued operations for all periods. Effective July 8, 2003, NEGT and its subsidiaries are no longer consolidated by PG&E Corporation in its Consolidated Financial Statements. See Note 7 of the Notes to the Consolidated Financial Statements for further discussion.

(2) Operating income for first quarter 2004, as part of the implementation of its plan of reorganization, includes the Utility's recognition of a $2.2 billion, after-tax ($3.7 billion, pre-tax) Settlement Regulatory Asset and $0.7 billion, after-tax ($1.2 billion, pre-tax), for the Utility's retained generation regulatory assets. See Note 15 of the Notes to the Consolidated Financial Statements for further discussion.

(3) Operating income for the second quarter 2004, includes the net impact of the 2003 General Rate Case decision of approximately $432 million, pre-tax. As a result the Utility recorded various regulatory assets and liabilities associated with revenue requirement increases, recovery of retained generation assets, and unfunded taxes, depreciation, and decommissioning.

(4) Net income for the fourth quarter 2004, includes a gain on disposal of NEGT of approximately $684 million, net of tax. On October 29, 2004, the effective date of NEGT's plan of reorganization, PG&E Corporation's equity ownership in NEGT was cancelled. See Note 7 of the Notes to the Consolidated Financial Statements for further discussion.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of PG&E Corporation and Pacific Gas and Electric Company, or the Utility, is responsible for establishing and maintaining adequate internal control over financial reporting. PG&E Corporation's and the Utility's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, or GAAP. Internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of PG&E Corporation and the Utility, (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP and that receipts and expenditures are being made only in accordance with authorizations of management and directors of PG&E Corporation and the Utility, and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of internal control over financial reporting as of December 31, 2005, 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, 2005.

Deloitte & Touche LLP, an independent registered public accounting firm, has audited the Consolidated Financial Statements of PG&E Corporation and the Utility for the three years ended December 31, 2005, appearing in this annual report and has issued an attestation report on management's assessment of internal control over financial reporting, as stated in their report, which is included in this annual report on page 155.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of PG&E Corporation and subsidiaries (the "Company") and of Pacific Gas and Electric Company and subsidiaries (the "Utility") as of December 31, 2005 and 2004, and the related consolidated statements of income, cash flows and shareholders' equity of the Company and of the Utility for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of the respective managements of the Company and of the Utility. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinions.

In our opinion, such consolidated financial statements present fairly, in all material respects, the respective consolidated financial position of the Company and of the Utility as of December 31, 2005 and 2004, and the respective results of their consolidated operations and their cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 of the Notes to the Consolidated Financial Statements, in December 2005, the Company and the Utility adopted a new interpretation of accounting standards for asset retirement obligations. During March 2004, the Company changed the method of computing earnings per share. During 2003, the Company and the Utility adopted new accounting standards to account for asset retirement obligations and financial instruments with characteristics of both liabilities and equity.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's and the Utility's internal control over financial reporting as of December 31, 2005, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 15, 2006 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

DELOITTE & TOUCHE LLP

San Francisco, California
February 15, 2006

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

We have audited management's assessment, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*, that PG&E Corporation and subsidiaries (the "Company") and Pacific Gas and Electric Company and subsidiaries (the "Utility") maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's and the Utility's management is responsible for maintaining effective internal control over financial reporting and for their assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's and the Utility's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audits included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company and the Utility maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company and the Utility maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2005 of the Company and the Utility and our report dated February 15, 2006 expressed an unqualified opinion on those financial statements and financial statement schedules and included an explanatory paragraph relating to accounting changes.

DELOITTE & TOUCHE LLP

San Francisco, California
February 15, 2006

The following documents are available both on PG&E Corporation's website, www.pgecorp.com, and Pacific Gas and Electric Company's website, www.pge.com:

- The codes of conduct and ethics adopted by PG&E Corporation and Pacific Gas and Electric Company applicable to their respective directors, officers, and employees;
- PG&E Corporation's and Pacific Gas and Electric Company's corporate governance guidelines; and
- Key Board Committee charters, including charters for the companies' Audit Committees and the PG&E Corporation Nominating, Compensation, and Governance Committee.

Shareholders also may obtain print copies of these documents by submitting a written request to Linda Y.H. Cheng, Vice President and Corporate Secretary of both PG&E Corporation and Pacific Gas and Electric Company, One Market, Spear Tower, Suite 2400, San Francisco, California 94105.

On May 19, 2005, Peter A. Darbee, who at the time was President and Chief Executive Officer of PG&E Corporation, submitted an Annual CEO Certification to each of the New York Stock Exchange and Pacific Exchange, certifying that he was not aware of any violation by PG&E Corporation of the respective stock exchange's corporate governance listing standards.

BOARDS OF DIRECTORS OF PG&E CORPORATION AND PACIFIC GAS AND ELECTRIC COMPANY[1]

DAVID R. ANDREWS
Senior Fellow for Corporate Governance, National Chamber Foundation, U.S. Chamber of Commerce

LESLIE S. BILLER
Vice Chairman and Chief Operating Officer, Retired, Wells Fargo & Company

DAVID A. COULTER
Managing Director and Senior Advisor, Warburg Pincus, LLC

C. LEE COX
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 and Chairman of the Board, Pacific Gas and Electric Company

MARYELLEN C. HERRINGER
Attorney-at-Law

THOMAS B. KING[1]
President and Chief Executive Officer, Pacific Gas and Electric Company

MARY S. METZ
President, Retired, S.H. Cowell Foundation

BARBARA L. RAMBO
Chief Executive Officer, Nietech Corporation

BARRY LAWSON WILLIAMS
President, Williams Pacific Ventures, Inc.

(1) The composition of the Boards of Directors is the same, except that Thomas B. King is a member of the Pacific Gas and Electric Company Board of Directors only.

PERMANENT COMMITTEES OF THE BOARDS OF DIRECTORS OF PG&E CORPORATION AND PACIFIC GAS AND ELECTRIC COMPANY[1]

EXECUTIVE COMMITTEES

Subject to certain limits, may exercise the powers and perform the duties of the Boards of Directors.

Peter A. Darbee, *Chair*
David A. Coulter
C. Lee Cox
Thomas B. King[1]
Mary S. Metz
Barry Lawson Williams

AUDIT COMMITTEES

Review financial and accounting practices, internal controls, external and internal auditing programs, business ethics, and compliance with laws, regulations, and policies that may have a material impact on the Consolidated Financial Statements. Satisfy themselves as to the independence and competence of the independent registered public accounting firm, select and appoint the independent registered public accounting firm to audit PG&E Corporation's and Pacific Gas and Electric Company's accounts and internal control over financial reporting, and pre-approve all audit and non-audit services provided by the independent registered public accounting firm.

Barry Lawson Williams, *Chair*
David R. Andrews
Leslie S. Biller
Maryellen C. Herringer
Mary S. Metz

FINANCE COMMITTEE

Reviews financial and capital investment policies and objectives and specific actions required to achieve those objectives, long-term financial and investment plans and strategies, annual financial plans, dividend policy, short-term and long-term financing plans, proposed capital expenditures, proposed divestitures, major commercial and investment banking, financial consulting, and other financial relations, and risk management activities. Annually reviews a five-year financial plan that incorporates PG&E Corporation's business strategy goals, as well as an annual budget that reflects elements of the approved five-year plan.

David A. Coulter, *Chair*
Leslie S. Biller
C. Lee Cox
Barbara L. Rambo
Barry Lawson Williams

NOMINATING, COMPENSATION, AND GOVERNANCE COMMITTEE

Recommends candidates for nomination as directors and reviews the composition, performance, and compensation of the Boards of Directors. Reviews corporate governance matters, including the Corporate Governance Guidelines of PG&E Corporation and Pacific Gas and Electric Company. Reviews employment, compensation, and benefits policies and practices, and long-range planning for executive development and succession.

C. Lee Cox, *Chair*
David A. Coulter
Barbara L. Rambo
Barry Lawson Williams

PUBLIC POLICY COMMITTEE

Reviews public policy issues that could significantly affect the interests of customers, shareholders, or employees, policies and practices with respect to those issues, and significant societal, governmental, and environmental trends and issues that may affect the operations of PG&E Corporation, Pacific Gas and Electric Company, or their respective subsidiaries.

Mary S. Metz, Chair
David R. Andrews
Maryellen C. Herringer

(1) Except for the Executive and Audit Committees, all committees listed above are committees of the PG&E Corporation Board of Directors. The Executive and Audit Committees of the PG&E Corporation and Pacific Gas and Electric Company Boards have the same members, except that Thomas B. King is a member of the Pacific Gas and Electric Company Executive Committee only.

PG&E CORPORATION OFFICERS

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

LESLIE H. EVERETT
Senior Vice President,
Communications and Public Affairs

KENT M. HARVEY
Senior Vice President and
Chief Risk and Audit Officer

RUSSELL M. JACKSON
Senior Vice President, Human Resources

CHRISTOPHER P. JOHNS
Senior Vice President,
Chief Financial Officer, and Treasurer

THOMAS B. KING
Senior Vice President

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

BRUCE R. WORTHINGTON
Senior Vice President and
General Counsel

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

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

G. ROBERT POWELL
Vice President and Controller

GABRIEL B. TOGNERI
Vice President, Investor Relations

JAMES A. TRAMUTO
Vice President,
Federal Governmental Relations

PACIFIC GAS AND ELECTRIC COMPANY OFFICERS

PETER A. DARBEE
Chairman of the Board

THOMAS B. KING
President and Chief Executive Officer

THOMAS E. BOTTORFF
Senior Vice President,
Regulatory Relations

JEFFREY D. BUTLER
Senior Vice President, Energy Delivery

HELEN A. BURT
Senior Vice President and
Chief Customer Officer

RUSSELL M. JACKSON
Senior Vice President, Human Resources

CHRISTOPHER P. JOHNS
Senior Vice President,
Chief Financial Officer, and Treasurer

JOHN (JACK) S. KEENAN
Senior Vice President,
Generation and Chief Nuclear Officer

ROGER J. PETERS
Senior Vice President and
Chief Utility Counsel

BEVERLY Z. ALEXANDER
Vice President, Customer Service

OPHELIA B. BASGAL
Vice President, Civic Partnership and
Community Initiatives

JAMES R. BECKER
Vice President, Diablo Canyon Power
Plant Operations and Station Director

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

DEANN HAPNER
Vice President, FERC and ISO Relations

ROBERT L. HARRIS
Vice President, Environmental Services

ROBERT T. HOWARD
Vice President,
Gas Transmission and Distribution

DONNA JACOBS
Vice President, Nuclear Services

ROY M. KUGA
Vice President, Gas and Electric Supply

PATRICIA M. LAWICKI
Vice President and
Chief Information Officer

NANCY E. MCFADDEN
Vice President, Governmental Relations

DINYAR B. MISTRY
Vice President, State Regulation

DAVID H. OATLEY
Vice President and General Manager,
Diablo Canyon Power Plant

G. ROBERT POWELL
Vice President and Controller

STEWART M. RAMSAY
Vice President, Asset Management and
Electric Transmission

WALTER R. RHODES
Vice President, Strategic Sourcing and
Operations Support

KIMBERLY R. WALSH
Vice President, Communications

FONG WAN
Vice President, Energy Procurement

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.

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

Mellon Investor Services

P.O. Box 3310 (Securities Transfer)
P.O. Box 3316 (General Correspondence)
P.O. Box 3317 (Lost Certificate Replacement)
P.O. Box 3339 (Investor Services Program)
South Hackensack, NJ 07606

Toll-free Telephone Services: 1.800.719.9056
Website: www.melloninvestor.com

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

Vice President, Corporate Governance and Corporate Secretary

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

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

Vice President, Investor Relations

Gabriel B. Togneri
PG&E Corporation
One Market, Spear Tower
Suite 2400
San Francisco, CA 94105-1126
415.267.7080
Fax 415.267.7265

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, Pacific, 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 8 issues of preferred stock, all of which are listed on the American and Pacific stock exchanges.

Issue	Newspaper Symbol[1]
First Preferred, Cumulative, Par Value $25 Per Share	
Non-Redeemable:	
6.00%	PacGE pfA
5.50%	PacGE pfB
5.00%	PacGE pfC
Redeemable:	
5.00%	PacGE pfD
5.00% Series A	PacGE pfE
4.80%	PacGE pfG
4.50%	PacGE pfH
4.36%	PacGE pfI

2006 Dividend Payment Dates

PG&E Corporation Common Stock

January 16
April 15
July 15
October 15

Pacific Gas and Electric Company Preferred Stock

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 Mellon Investor Services in the broker's name, or "street name." Mellon Investor Services 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 which 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 Investor Services Program

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 Investor Services Program (ISP). You may obtain an ISP brochure and enroll by contacting Mellon Investor Services. If your shares are held by a broker (in "street name"), you are not eligible to participate in the ISP.

Direct Deposit of Dividends

If you hold stock in your own name, rather than through a broker, you may have your common and/or preferred dividends transmitted to your bank electronically. You may obtain a direct deposit authorization form by contacting Mellon Investor Services.

Replacement of Dividend Checks

If you hold stock in your own name and do not receive your dividend check within 10 days after the payment date, or if a check is lost or destroyed, you should notify Mellon Investor Services so that payment can be stopped on the check and a replacement 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 Mellon Investor Services immediately.

(1) Local newspaper symbols may vary.

PG&E CORPORATION
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL MEETINGS OF SHAREHOLDERS

Date: April 19, 2006
Time: 10:00 a.m.
Location: San Ramon Valley Conference Center
3301 Crow Canyon Road
San Ramon, California

A joint notice of the annual meetings, joint proxy statement, and proxy card are being mailed with this annual report on or about March 14, 2006, to all shareholders of record as of February 21, 2006.

FORM 10-K

If you would like a copy of the 2005 Annual Report on Form 10-K filed with the Securities and Exchange Commission, free of charge, please contact the Corporate Secretary's office, or visit our websites, www.pgecorp.com and www.pge.com.

PG&E Corporation's and Pacific Gas and Electric Company's officer certifications required by Section 302 of the Sarbanes-Oxley Act have been filed as exhibits to the 2005 Annual Report on Form 10-K.

This report was printed at facilities that have a zero-landfill, 100% recycling policy for all hazardous and non-hazardous waste. The full-color contents were printed at a facility that also generates all of its own electrical and thermal power, and is the only Air Quality Management District-certified totally enclosed commercial print facility in the nation, which means its production operations release virtually zero volatile organic compound emissions to the atmosphere.

DESIGN: PENTAGRAM PHOTOGRAPHY: JOHN ELAUSTEIN, BOARD OF DIRECTORS PHOTOGRAPHY: JIM VARADEORGE

PG&E Corporation.