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PG&E Corporation™

2001 Annual Report

Corporate Overview

PG&E Corporation is a national energy-based holding company with approximately $23 billion in revenues in 2001, and approximately $36 billion in assets at the end of 2001. It markets energy services and products throughout North America through its subsidiary PG&E National Energy Group, Inc., and is the parent company of Pacific Gas and Electric Company (the Utility), the Northern and Central California utility that delivers natural gas and electricity service to one in every 20 Americans.

Financial Highlights
PG&E Corporation

(unaudited, dollars in millions, except per share amounts)	2001	2000
Operating Revenues	$ 22,959	$ 26,220
Net Income (Loss)		
Net income from operations[1]	1,099	925
Items impacting comparability[2]	—	(4,289)
Reported net income (loss)	$ 1,099	$ (3,364)
Income (Loss) Per Common Share, fully diluted		
Net income from operations[1]	$ 3.02	$ 2.54
Items impacting comparability[2]	—	(11.83)
Reported net income (loss) per common share	$ 3.02	$ (9.29)
Dividends Per Common Share	$ —	$ 1.20
Total Assets	$ 35,862	$ 36,152
Number of common shareholders at December 31	125,739	138,467
Number of common shares outstanding at December 31	387,898,848[3]	387,193,727[3]

(1) Net income from operations excludes items impacting comparability and should not be considered an alternative to net income as prescribed by accounting principles generally accepted in the United States.

(2) Items impacting comparability in 2001 include the collection of previously written-off transition costs of $458 million ($1.26 per share) and the cumulative effect of a change in accounting principle of $9 million ($0.02 per share) partially offset by a loss of $66 million ($0.18 per share) on involuntary terminations of gas transportation hedges resulting from the Utility's bankruptcy; incremental interest costs of $262 million ($0.72 per share) from the increased amount and cost of debt resulting from the California energy crisis and the Utility's bankruptcy; increased costs of $78 million ($0.21 per share) related to the Utility's bankruptcy and generally consisting of external legal consulting and financial advisory fees; the net prior year impacts associated with current year decisions issued by the California Public Utilities Commission on rehearings of the Utility's 1999 General Rate Case of $26 million ($0.07 per share); and the loss on termination of certain contracts with Enron Corp. of $35 million ($0.10 per share) attributed to its bankruptcy filing.

Items impacting comparability in 2000 include the write-off of regulatory assets at the Utility of $4,111 million ($11.36 per share); the impact of an inability to fully utilize the tax benefits of losses in California of $79 million ($0.22 per share); adjustments to the estimated loss on disposal of the retail energy services unit of $40 million ($0.11 per share); a favorable actualization of $20 million ($0.06 per share) on the sale of the Texas natural gas liquids and natural gas pipeline business unit, which closed on December 22, 2000; an $83 million charge ($0.23 per share) related to an adjustment to legal reserves at the Utility; $4 million ($0.01 per share) of other items; and $0.02 per share of dilution.

(3) The common shares outstanding include 23,815,500 shares held by a wholly owned subsidiary of PG&E Corporation. These shares are treated as treasury stock in the Consolidated Financial Statements.

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Dear PG&E Corporation Shareholder:

The year 2001 began with the uncertainty and challenges of the California energy crisis. It ended on much firmer footing. Your company achieved solid financial and operational results, and presented a clear vision for reaffirming the financial health of our business and rebuilding shareholder value.

The results of 2001 included:

- Surpassing our earnings growth target by increasing earnings from operations by 19 percent over 2000 results, from $2.54 per share to $3.02 per share.
- Announcing plans to enable Pacific Gas and Electric Company to exit Chapter 11.
- Delivering on our continued commitment to provide customers with safe, reliable and responsive gas and electric utility service.
- Growing the contributions from our national energy business and continuing to build its asset base with strategically chosen electric and natural gas projects.

In this letter, we discuss each of these areas and other highlights from the year, as well as our outlook for 2002.

2001 Financial Performance

In 2001, for the fourth consecutive year, we achieved or exceeded our financial goal to grow earnings from operations by 8-10 percent annually. The Corporation's earnings from operations rose from $2.54 per share in 2000 to $3.02 per share in 2001, demonstrating that the underlying performance in our businesses remains very solid.

Our California utility business, Pacific Gas and Electric Company, earned $2.51 per share from operations in 2001, compared with $2.11 per share in 2000. PG&E National Energy Group in 2001 earned $0.57 per share from operations, compared with $0.45 per share in 2000.

PG&E Corporation's bottom-line earnings for 2001 were $3.02 per share, compared with a loss for the prior year of $9.29 per share due to the write-off in 2000 of $4.1 billion in wholesale power and transition costs that were not covered by retail rates. We incurred a further write-off of $1.1 billion for wholesale power costs in the first quarter of 2001. During the remainder of the year, however, higher revenues and lower costs allowed us to offset this. These offsets are included in our total net income of $3.02 per share. (Per share values are per diluted share.)

2001 Accomplishments

Our teams across the company stayed focused on ensuring the safe, reliable operation of our facilities and delivering service to our customers, while managing the challenges of the California energy crisis and changes in competitive energy markets. One result of this focus was that safety performance improved over the prior year.

Pacific Gas and Electric Company:

We focused attention and resources on making certain our customers continued to receive safe and reliable electric and gas service.

Here are a few examples.

- In the first half of the year, we worked successfully with power and natural gas suppliers to put in place financial solutions that ensured they would be able to continue providing gas and electricity for our customers.
- The team at our Diablo Canyon Nuclear Power Plant refueled its Unit 2 in a record 29 days, making sure the unit, which provides enough power for 1 million homes, was back in full operation in time for summer demand. The refueling was completed on budget and was also the safest ever in the plant's history. The plant achieved an operating capacity factor of 99.4 percent for the year.
- Diablo Canyon once again received the top rating for safety and operational performance from the Institute of Nuclear Power Operations.
- We streamlined the process and increased the resources assigned for connecting new power plants to the transmission grid. In total, we connected 14 plants to the grid for 2001, totaling 1,200 megawatts.
- We completed 30 critical transmission capacity projects in order to move more power to the regions and communities where demand increased.

- We assisted a record-breaking 18.8 million callers to our call centers, nearly a 30 percent increase over the numbers for the previous year.
- Our focus on safe, reliable, responsive service earned the company high marks from commercial and residential customers, with nearly nine out of 10 customers surveyed rating our services as good, very good or excellent. In a year like 2001, we are doubly proud of these results.

We are also proud of our successes in energy conservation, in which we continued a 25-year track record of excellence.

- We offered more than 30 energy efficiency programs to lower business and residential customers' energy usage and bills, create more efficient new buildings, and reduce impacts on the environment. In 2001, these programs, in which we have invested more than $2 billion since 1976, saved enough power to supply 90,000 homes for one year, and enough natural gas to supply 19,000 homes for a year.
- Our energy efficiency rebate programs paid more than $17 million in customer rebates to residential customers, who purchased a record 150,000 qualifying energy efficient appliances for the year. Business customers received $21 million in rebates for purchases of energy efficient equipment.
- We educated customers about how they could reduce energy usage, making information available through brochures, bill inserts, our website, the media, advertising, and our toll-free Smarter Energy Line, which helped approximately 530,000 callers last year—double the number from the previous year.
- We received the 2001 ENERGY STAR "Excellence in Consumer Education Award" from the U.S. Department of Energy and the U.S. Environmental Protection Agency for our promotion of energy efficient appliances.
- These programs helped California reduce energy usage during the summer of 2001 and helped avoid the rotating blackouts many people thought were inevitable.

PG&E National Energy Group:

We continued solid operational performance at our PG&E NEG facilities and in its energy trading business in 2001, amid the energy crisis and changes in competitive markets.

We continued to access the capital markets, notwithstanding Pacific Gas and Electric Company's bankruptcy. Early last year, we sought and obtained independent investment-grade credit ratings for the PG&E NEG and its energy trading business. Those ratings were reaffirmed following Pacific Gas and Electric Company's Chapter 11 filing.

We completed several financings providing capital to invest in generating and pipeline assets and to support energy trading activities. These included $1 billion of 10-year senior notes, a new $1.25 billion revolving credit facility that expanded and consolidated other credit facilities, and a $1.1 billion loan facility to finance the Athens, Harquahala and Millennium power plant projects.

Power plant development and construction accomplishments included:

- Commencing commercial operations in June at the 526-megawatt Attala power plant in Mississippi, and in Galion, Ohio, beginning operations at the final unit of the 144-megawatt multi-unit, multi-site peaker project.
- Starting construction on the 1,092-megawatt Harquahala plant in Arizona, the 1,080-megawatt Athens plant in New York and the 111-megawatt Plains End facility in Colorado.
- Breaking ground on the 1,170-megawatt Covert generating project in southwest Michigan.
- Announcing an agreement between the PG&E NEG and the city of Denton, Texas, under which the company acquired a 178-megawatt generating facility and agreed to a power sales contract with the city.
- Taking ownership of the 66-megawatt Mountain View wind-generating facility in Southern California, which sells its power to the California Department of Water Resources under a 10-year contract.

At year's end, our portfolio of megawatts owned and controlled totaled 7,100 megawatts in operation and 7,740 megawatts in construction.

Natural gas transmission accomplishments included:

- Beginning operation of 21 miles of new pipeline in time for the 2001-2002 winter heating season. Completed a year ahead of schedule, this section is part of our larger 2002 expansion project that will increase the company's ability to deliver natural gas to western markets. The 2002 expansion project in total will increase capacity on the system by about 8 percent.

- Continuing work on the North Baja pipeline project in Southern California, which is on target for commercial operation by the end of 2002.

Pacific Gas and Electric Company's Chapter 11 and Plan of Reorganization

On September 20, 2001, Pacific Gas and Electric Company and PG&E Corporation jointly filed a Plan of Reorganization with the Bankruptcy Court. This plan is the basis for the resolution of Pacific Gas and Electric Company's Chapter 11 case.

- It will allow us to pay all valid creditor claims in full, without asking the court to raise retail rates, asking the state for a bailout, or selling any of our major assets to third parties.
- It will create financially strong, sustainable businesses that offer long-term growth prospects to our employees and shareholders.
- And it will enable Pacific Gas and Electric Company to move out of Chapter 11 as a financially strong business positioned to continue safe, reliable and responsive delivery of gas and electricity to its customers.

The plan substantially restructures Pacific Gas and Electric Company's current operations. It also clearly aligns the business environment with the regulatory environment for our reorganized businesses. Together, these changes will result in businesses that can secure new financing that will help provide the funds we need to resolve creditors' valid claims.

Here is how the restructuring will work.

The plan reorganizes Pacific Gas and Electric Company and PG&E Corporation into two separate, stand-alone publicly traded companies no longer affiliated with one another.

Pacific Gas and Electric Company will retain its current name and 70 percent of its current assets. It will be a separate California corporation with its own publicly traded common stock, which will be distributed to PG&E Corporation shareholders. And it will continue to own and operate the existing retail electric and natural gas distribution system and provide natural gas and electric service to one in 20 Americans.

The electric generation, electric transmission and natural gas transmission operations currently part of Pacific Gas and Electric Company will become subsidiaries of PG&E Corporation. PG&E Corporation, which will be renamed, will consist of three new businesses—temporarily named Gen, ETrans and GTrans—in addition to its existing National Energy Group business.

Each of these businesses—Pacific Gas and Electric Company and the reorganized PG&E Corporation—will be financially strong and will be a solid, sustainable business going forward. As a result, the businesses will be able to use the value of their assets to obtain substantial new financing that will be used to help pay creditors' claims.

Following this reorganization, roles and responsibilities for the vast majority of our employees will be the same as they are today. We envision essentially the same people continuing to do their jobs with comparable pay and benefits programs. In general, work will follow the assets, and people will follow the work.

The Chapter 11 process requires that the plan of reorganization ultimately be confirmed by the Bankruptcy Court before it can be implemented. The official creditors' committee is fully supportive of the plan. We anticipate confirmation of the plan in mid-2002 and receipt of various federal regulatory approvals thereafter. Our schedule is to complete the reorganization process by the end of 2002.

Management Focus and Expectations for 2002

Management's primary focus in 2002 is on the following objectives:

- Gaining approval for and implementing our Plan of Reorganization.
- Strengthening the balance sheet and credit ratings in the PG&E NEG.
- Deploying capital prudently in the PG&E NEG, which is moving forward with its pipeline expansion program as well as current plants in construction, totaling more than 5,400 megawatts, plus about 2,300 megawatts from tolling agreements.
- Continuing to provide safe, reliable service to customers and to improve our safety performance through effective safety programs and a focus on maintaining safe operations.
- Delivering solid income from operations.

Thank You

In such a tumultuous year, it is important to thank our employees, customers, creditors and investors for the support they have shown the company.

In the wake of September 11, several hundred of our team members donated 5,300 vacation hours to raise $200,000 for the American Red Cross. Others scaled back holiday celebrations for the same purpose. And, as this letter is written, some men and women from our company are called to active duty by the U.S. armed forces reserves and the National Guard to help make the United States safer.

We know your investment in our company is made with the expectation of a growing total return. I can speak for our entire team in assuring you that we all share a commitment to deliver this to you.

Sincerely,

Robert D. Glynn, Jr.
Chairman of the Board, Chief Executive Officer and President
PG&E Corporation

March 5, 2002

PG&E Corporation At A Glance

PG&E National Energy Group

	2001	2000
Operating revenues	$12.7 billion	$16.8 billion
Earnings from operations per common share*	$0.57	$0.45

Products and services	Integrated energy and marketing Interstate pipeline operations
Operating power plants (owned and leased)	6,518 megawatts
Power plants in construction (owned and leased)	5,430 megawatts
Power controlled through contracts	581 megawatts in operation; 2,313 megawatts under construction
Energy trading volume in 2001:	
Natural gas	8.45 billion cubic feet per day
Power	280 million megawatt-hours
Natural gas pipelines in operation	1,350 miles in the Pacific Northwest
Natural gas pipelines in development	77 miles in Southern California and Arizona
Average daily natural gas throughput	2.75 billion cubic feet

Pacific Gas and Electric Company

	2001	2000
Operating revenues	$10.5 billion	$9.6 billion
Earnings from operations per common share*	$2.51	$2.11

Service area	70,000 square miles in Northern and Central California, with a population of 13 million, about one in 20 Americans
Delivery systems	131,000 circuit miles of electric transmission and distribution lines, 43,000 miles of natural gas transmission and distribution pipelines
Recent investments in infrastructure	$1.3 billion in 2001 and $1.2 billion in 2000
A few of the customers served by Pacific Gas and Electric Company	1,022 wineries, 26 gold mines, 2,212 bakeries, 985 shoe stores, 1,409 video rental stores, 1,285 golf courses, 1,115 florists, and 975 car washes
Estimated energy savings through customer energy efficiency programs in 2001	630 million kilowatt-hours of electricity, or the equivalent to supply 90,000 households for one year 11 million therms of natural gas, or the equivalent to supply 19,000 homes for one year

* Earnings from operations per common share exclude items impacting comparability and should not be considered as an alternative to net income as prescribed by accounting principles generally accepted in the United States.

The Plan of Reorganization At A Glance

On September 20, 2001, Pacific Gas and Electric Company and PG&E Corporation jointly filed a Plan of Reorganization for Pacific Gas and Electric Company with the Bankruptcy Court. The plan, which must receive Bankruptcy Court approval, will:

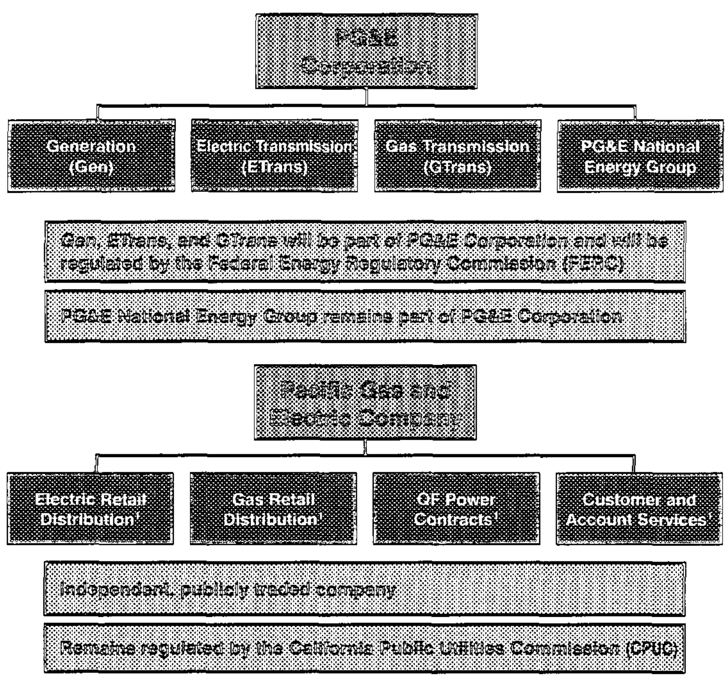
- Allow Pacific Gas and Electric Company to pay all valid creditor claims in full, without asking the court to raise retail rates, asking the state for a bailout, or selling any of our major assets to third parties.
- Create financially strong, sustainable businesses that offer long-term growth prospects to our employees and shareholders.
- Enable Pacific Gas and Electric Company to move out of Chapter 11 as a financially strong business positioned to continue safe, reliable and responsive delivery of gas and electricity to its customers.

The plan substantially restructures Pacific Gas and Electric Company's current operations. It also clearly aligns the business environment with the regulatory environment for our reorganized businesses.

The plan separates Pacific Gas and Electric Company and PG&E Corporation into two stand-alone publicly traded companies no longer affiliated with one another. The common shares of the reorganized Pacific Gas and Electric Company will be distributed to PG&E Corporation shareholders.

The following chart shows the two companies as they will be organized after the plan is implemented:

Proposed Corporate Structure



[1] *Will not operate as separate subsidiaries*

Pacific Gas and Electric Company:

- Pacific Gas and Electric Company will be the largest of the reorganized units, with 70 percent of the current utility assets (in terms of book value). Pacific Gas and Electric Company will retain its current name.
- It will have approximately 16,000 employees and generate approximately $10 billion to $12 billion in annual revenues.
- It will be a separate California corporation with its own publicly traded common stock.
- Retail customers of Pacific Gas and Electric Company will continue to receive all of the same electric and natural gas services they currently receive.

PG&E Corporation:

- PG&E Corporation will have three new businesses—temporarily named Gen, ETrans and GTrans—in addition to its existing National Energy Group business, with its integrated energy and marketing and interstate pipeline operations.
- Gen will own and operate the hydroelectric and nuclear generation facilities and associated lands, and will assume existing power purchase contracts with irrigation districts. These assets represent approximately 7,100 megawatts of power and currently produce about 40 percent of the demand of the utility's retail electric customers. The power will be sold back to Pacific Gas and Electric Company under contract for 12 years.
- ETrans will own and operate the bulk and local transmission system. In addition to maintaining the existing system for efficiency and reliability, ETrans will be responsible for the continued expansion of the electric transmission system in order to meet customer growth and market needs.
- GTrans will operate 6,300 miles of transmission pipelines and three gas storage facilities, including the transmission pipeline that forms the backbone of the natural gas delivery infrastructure for Northern and Central California.

SELECTED FINANCIAL DATA

(in millions, except per share amounts)	2001	2000	1999	1998	1997
PG&E Corporation[1]					
For the Year					
Operating revenues	$22,959	$26,220	$20,819	$19,577	$15,255
Operating income (loss)	2,736	(4,807)	878	2,098	1,762
Income (Loss) from continuing operations	1,090	(3,324)	13	771	745
Earnings (Loss) per common share from continuing operations, basic	3.00	(9.18)	0.04	2.02	1.82
Earnings (Loss) per common share from continuing operations, diluted	2.99	(9.18)	0.04	2.02	1.82
Dividends declared per common share	—	1.20	1.20	1.20	1.20
At Year-End					
Book value per common share	$ 11.91	$ 8.76	$ 19.13	$ 21.08	$ 21.30
Common stock price per share	19.24	20.00	20.50	31.50	30.31
Total assets	35,862	36,152	29,588	33,234	31,115
Long-term debt (excluding current portion)	7,297	5,550	6,785	7,422	7,659
Rate reduction bonds (excluding current portion)	1,450	1,740	2,031	2,321	2,611
Financial debt subject to compromise	5,651	—	—	—	—
Redeemable preferred stock and securities of subsidiaries (excluding current portion)	635	635	635	635	750
Pacific Gas and Electric Company[1]					
For the Year					
Operating revenues	$10,462	$ 9,637	$ 9,228	$ 8,924	$ 9,495
Operating income (loss)	2,478	(5,201)	1,993	1,876	1,820
Income (Loss) available for (allocated to) common stock	990	(3,508)	763	702	735
At Year-End					
Total assets	$25,137	$21,988	$21,470	$22,950	$25,147
Long-term debt (excluding current portion)	3,019	3,342	4,877	5,444	6,218
Rate reduction bonds (excluding current portion)	1,450	1,740	2,031	2,321	2,611
Financial debt subject to compromise	5,651	—	—	—	—
Redeemable preferred stock and securities (excluding current portion)	586	586	586	586	694

(1) Matters relating to certain data, including the provision for loss on generation-related regulatory assets and under-collected purchased power costs, discontinued operations, and the cumulative effect of a change in accounting principles, are discussed in Management's Discussion and Analysis and in the Notes to the Consolidated Financial Statements.

MANAGEMENT'S DISCUSSION AND ANALYSIS

PG&E Corporation is an energy-based holding company headquartered in San Francisco, California. PG&E Corporation's energy utility subsidiary, Pacific Gas and Electric Company (the Utility), delivers electric service to approximately 4.8 million customers and natural gas service to approximately 3.9 million customers in Northern and Central California. PG&E Corporation's other significant subsidiary is PG&E National Energy Group, Inc. (PG&E NEG), headquartered in Bethesda, Maryland. On April 6, 2001, the Utility filed a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code (Bankruptcy Code) in the United States Bankruptcy Court for the Northern District of California (Bankruptcy Court). Under Chapter 11, the Utility retains control of its assets and is authorized to operate its business as a debtor-in-possession while being subject to the jurisdiction of the Bankruptcy Court. The factors causing the Utility to take this action are discussed in this Management's Discussion and Analysis (MD&A) and in Notes 2 and 3 of the Notes to the Consolidated Financial Statements.

PG&E Corporation has identified three reportable operating segments, which were determined based on similarities in economic characteristics, products and services, types of customers, methods of distribution, the regulatory environment, and how information is reported to PG&E Corporation's key decision makers. These segments represent a change in the reportable segments from those reported in the year 2000. In accordance with accounting principles generally accepted in the United States, prior year segment information has been restated to conform to the current segment presentation. The Utility is one reportable operating segment. The other two reportable operating segments are the Integrated Energy and Marketing (PG&E Energy) and the Interstate Pipeline Operations (PG&E Pipeline) segments of PG&E Corporation's subsidiary, PG&E NEG. These three reportable operating segments provide different products and services and are subject to different forms of regulation or jurisdictions. Financial information about each reportable operating segment is provided in this MD&A and in Note 17 of the Notes to the Consolidated Financial Statements.

PG&E NEG is an integrated energy company with a strategic focus on power generation, natural gas transmission, and wholesale energy marketing and trading in North America. PG&E NEG and its subsidiaries have integrated their generation, development, and energy marketing and trading activities in an effort to create energy products in response to customer needs, increase the returns from its operations, and identify and capitalize on opportunities to optimize generating and pipeline capacity. PG&E NEG was incorporated on December 18, 1998, as a wholly owned subsidiary of PG&E Corporation. Shortly thereafter, PG&E Corporation contributed various subsidiaries to PG&E NEG. The principal subsidiaries of PG&E NEG include: PG&E Generating Company, LLC and its subsidiaries (collectively, PG&E Gen LLC); PG&E Energy Trading Holdings Corporation and its subsidiaries (collectively, PG&E Energy Trading or PG&E ET); PG&E Gas Transmission Corporation and its subsidiaries (collectively, PG&E GTC), which includes PG&E Gas Transmission, Northwest Corporation and its subsidiaries (collectively, PG&E GTN), PG&E North Baja Pipeline, LLC (PG&E NBP), and PG&E Gas Transmission, Texas Corporation and its subsidiaries, and PG&E Gas Transmission Teco, Inc. and its subsidiaries (collectively, PG&E GTT) (see Note 6 of the Notes to the Consolidated Financial Statements for a discussion of the sale of PG&E GTT). PG&E Energy Services Corporation (PG&E ES), which was discontinued in 1999, provided retail energy services. PG&E NEG also has other less significant subsidiaries.

This is a combined annual report of PG&E Corporation and the Utility. It includes separate consolidated financial statements for each entity. The consolidated financial statements of PG&E Corporation reflect the accounts of PG&E Corporation, the Utility, PG&E NEG, and other wholly owned and controlled subsidiaries. The consolidated financial statements of the Utility reflect the accounts of the Utility and its wholly owned and controlled subsidiaries. This combined MD&A should be read in conjunction with the consolidated financial statements included herein.

This combined annual report, including our Letter to Shareholders and this MD&A, contains forward-looking statements about the future that are necessarily subject to various risks and uncertainties. These statements are based on current expectations and on assumptions which management believes are reasonable and on information currently available to management. These forward-looking statements are identified by words such as "estimates," "expects," "anticipates," "plans," "believes," and other similar expressions. Actual results could differ materially from those contemplated by the forward-looking statements.

Although PG&E Corporation and the Utility are not able to predict all of the factors that may affect future results, some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include:

- the outcome of the Utility's bankruptcy case, including:
  - whether the Bankruptcy Court approves the amended disclosure statement relating to the Utility's proposed plan of reorganization (Plan) to be submitted to comply with the Bankruptcy Court's February 7, 2002 decision;
  - whether the Bankruptcy Court confirms the Utility's Plan as amended to comply with the Bankruptcy Court's February 7, 2002 decision;
  - whether the Bankruptcy Court confirms the alternative plan of reorganization to be submitted by the California Public Utilities Commission (CPUC) and the terms of such a plan;
  - whether other parties submit alternative proposed plans of reorganization after the expiration of the period during which only the Utility may file a proposed plan;
  - whether the CPUC takes action that would negatively affect the feasibility of the proposed Plan;
  - whether the Plan is materially modified or amended;
  - whether the Utility is required to re-assume the obligation to purchase power for its customers from the California Department of Water Resources (DWR) under circumstances that threaten to undermine the Utility's creditworthiness, financial condition, or results of operation;
  - whether the Utility is required to accept assignment of the DWR's power purchase contracts;
- assuming the Bankruptcy Court confirms the proposed Plan, whether such confirmation can be challenged or appealed and the impact of any delay caused by such challenges or appeals on continued creditor support of the Plan and on continued feasibility of the Plan;
- whether, even if confirmed, the Plan becomes effective, which may be affected by, among other factors:
  - risks relating to the issuance of new debt securities by each of the disaggregated entities, including higher interest rates than are assumed in the financial projections which could affect the amount of cash that could be raised to satisfy allowed claims, and the inability to successfully market the debt securities due to, among other reasons, an adverse change in market conditions or in the condition of the disaggregated entities before completion of the offerings;
  - whether a favorable tax ruling or opinion is obtained regarding the tax-free nature of the transactions contemplated in the Plan;
  - whether approval is obtained from the various federal regulatory agencies to implement the transactions contemplated in the Plan, the timing of that approval, and the timing and success of any appeals of such regulatory orders;
- assuming the Plan becomes effective, whether the Utility will be able to successfully disaggregate its businesses;
- the effect of the Utility's bankruptcy proceedings on PG&E Corporation and PG&E NEG, and in particular, the impact a protracted delay in the Utility's bankruptcy proceedings could have on PG&E Corporation's liquidity and access to capital markets;
- the outcome of the CPUC's pending investigation into whether the California investor-owned utilities, including the Utility, have complied with past CPUC decisions, rules, or orders authorizing their holding company formations, the outcomes of the lawsuits brought by the California Attorney General, the City and County of San Francisco, and the People of the State of California, against PG&E Corporation alleging unfair or fraudulent business acts or practices based on alleged violations of conditions established in the CPUC's holding company decisions, and the outcome of the California Attorney General's petition requesting revocation of PG&E Corporation's exemption from the Public Utility Holding Company Act of 1935, and the effect of such outcomes, if any, on PG&E Corporation, the Utility, and PG&E NEG;

- the extent to which the ability of PG&E Corporation to obtain financing or capital on reasonable terms is affected by the interpretation of the CPUC's holding company conditions, conditions in the general economy, the energy markets or capital markets;
- the outcome of the Utility's various regulatory proceedings pending at the CPUC, including the proceeding to determine future ratemaking for the Utility's retained generation (primarily hydroelectric assets and the Diablo Canyon Nuclear Power Plant), the 2002 attrition rate adjustment and the 2003 General Rate Case;
- whether the CPUC's March 27, 2001 accounting decision regarding the Utility's under-collected wholesale power purchase costs is upheld and whether the Utility's lawsuit against the CPUC for recovery of those costs is successful;
- any changes in the amount of transition costs the Utility is allowed to collect from its customers, and the timing of the completion of the Utility's transition cost recovery;
- the amount and timing of regulatory valuation of the Utility's hydroelectric and other non-nuclear generation assets;
- the impact on earnings of the future operating performance at the Utility's Diablo Canyon Nuclear Power Plant (Diablo Canyon);
- legislative or regulatory changes affecting the electric and natural gas industries in the United States, including the pace and extent of efforts to restructure the electric and natural gas industries;
- the volatility of commodity fuel and electricity prices (which may result from a variety of factors, including: weather; the supply and demand for energy commodities; the availability of competitively priced alternative energy sources; the level of production and availability of natural gas, crude oil, and coal; transmission or transportation constraints; federal and state energy and environmental regulation and legislation; the degree of market liquidity; and natural disasters, wars, embargoes, and other catastrophic events); any resulting increases in the cost of producing power and decreases in prices of power sold, and whether the Utility's and PG&E NEG's strategies to manage and respond to such volatility are successful;
- PG&E NEG's ability to obtain financing from third parties, or from PG&E Corporation for its planned development projects and related equipment purchases and to refinance PG&E NEG's and its subsidiaries' existing indebtedness as it matures, in each case, on reasonable terms, while preserving PG&E NEG's credit quality; which could be negatively affected by conditions in the general economy, the energy markets, or the capital markets; and the extent to which the CPUC's holding company conditions may be interpreted to restrict PG&E Corporation's ability to provide financial support to PG&E NEG;
- the extent to which PG&E NEG's current or planned development of generation, pipeline, and storage facilities are completed and the pace and cost of that completion, including the extent to which commercial operations of these development projects are delayed or prevented because of various development and construction risks such as PG&E NEG's failure to obtain necessary permits or equipment, the failure of third-party contractors to perform their contractual obligations, or the failure of necessary equipment to perform as anticipated;
- the extent and timing of generating, pipeline, and storage capacity expansion and retirements by others;
- the performance of PG&E NEG's projects and the success of PG&E NEG's efforts to invest in and develop new opportunities;
- restrictions imposed upon PG&E Corporation and PG&E NEG under certain term loans of PG&E Corporation including maintenance of minimum segregated cash balances by PG&E Corporation and prohibitions on payment of dividends by both PG&E Corporation and PG&E NEG;
- future sales levels, which in the case of the Utility, will be affected by when the CPUC ultimately determines that direct access has been suspended and the level of exit fees that may be imposed on direct access customers; general economic and financial market conditions; and changes in interest rates;
- volatility resulting from mark-to-market accounting and the extent to which the assumptions underlying PG&E NEG's and the Utility's mark-to-market accounting and risk management programs are not realized;
- the effect of compliance with existing and future environmental laws, regulations, and policies, the cost of which could be significant;

- heightened rating agency criteria and the impact of changes in credit ratings on PG&E NEG's future financial condition, particularly a downgrade below investment grade which would impair PG&E NEG's ability to meet liquidity calls in connection with its trading activities and obtain financing for its planned development projects;
- new accounting pronouncements; and
- the outcome of pending litigation.

As the ultimate impact of these and other factors is uncertain, these and other factors may cause future earnings to differ materially from results or outcomes currently sought or expected.

In this MD&A, we first discuss our earnings guidance, we then discuss the impact of the California energy crisis and the Utility's bankruptcy on our liquidity, and then PG&E NEG's liquidity. We then discuss statements of cash flows and financial resources, and our results of operations for 2001, 2000, and 1999. Finally, we discuss our competitive and regulatory environment, our risk management activities, and various uncertainties that could affect future earnings. Our MD&A applies to both PG&E Corporation and the Utility.

2002 Guidance

We expect 2002 corporate earnings from operations including headroom, the difference between generation-related revenues collected from customers at CPUC-authorized rates and our generation related costs, to be in the $3.00 per share range. (On a regulatory accounting basis, headroom recovers previously uncollected generation related costs that we wrote off at December 31, 2000.)

We are including headroom in earnings guidance for 2002 as a placeholder for increases in operating revenues that could result when the Utility's pending regulatory issues, such as the 2002 attrition rate adjustment, the retained generation ratemaking proceeding, and others are resolved. On a quarterly basis, we expect the amount of headroom to fluctuate materially due to many factors, including the outcome of regulatory proceedings and other regulatory actions, sales volatility, changes in estimates of previously incurred energy procurement costs, and the impact of the end of the rate freeze period. As a result, it is difficult to predict the amount of quarterly headroom.

Additionally, in light of the economy and energy markets, we expect that contribution to 2002 earnings from PG&E NEG will be down somewhat from 2001 results.

Earnings from operations exclude items impacting comparability and should not be considered an alternative to net income as prescribed by accounting principles generally accepted in the United States.

LIQUIDITY AND CAPITAL RESOURCES

As discussed below, the California energy crisis has impacted the credit ratings of various debt and equity instruments. The credit ratings as of December 31, 2001, of the various debt and equity instruments of PG&E Corporation, the Utility, and PG&E NEG are summarized in the table below:

	Credit Rating	
	Standard and Poors	Moody's Investors Service
PG&E Corporation		
GE/Lehman Loans	Not Rated	Private Rating
Utility		
Mortgage Bonds	CCC	B3
Pollution Control Bonds—Bond Insurance	AAA	Aaa
Pollution Control Bonds—Letters of Credit	AA to A+	Not Rated
Medium-Term Notes	D	Caa2
San Joaquin Valley Power Authority Bond	Not Rated	Rating W/D
DWR Loan	Not Rated	Not Rated
Senior 5-Year Note	D	Caa2
Revolving Credit Line	Not Rated	Not Rated
Floating Rate Notes	D	Not Rated
Matured Commercial Paper	D	Not Prime
Redeemed Pollution Control Bonds—Bank Loans	Not Rated	Not Rated
Quarterly Income Preferred Securities (QUIPS)	D	Caa3
Preferred Stock	D	Ca
PG&E NEG		
Senior Unsecured Notes due 2011 (PG&E NEG)	BBB	Baa2
Senior Unsecured Notes due 2005 (PG&E GTN)	A-	Baa1
Senior Unsecured Debentures due 2025 (PG&E GTN)	A-	Baa1
Medium-Term Notes (nonrecourse) (PG&E GTN)	A-	Baa1
Outstanding Credit Facilities	Various	Various
Term Loans-Gen Holdings	BBB-	Baa3
Mortgage Loans and Others	Not Rated	Not Rated

Utility

The California energy crisis described in Note 3 of the Notes to the Consolidated Financial Statements has had a significant negative impact on the liquidity and capital resources of the Utility. Beginning in June 2000, the wholesale price of electric power in California steadily increased to an average cost of $0.182 per kilowatt-hour (kWh) for the seven-month period June 2000 through December 2000, as compared to an average cost of $0.042 per kWh for the same period in 1999. During this period retail electric rates were frozen. The Utility was only permitted to collect approximately $0.054 per kWh in frozen retail rates from its customers to pay for the Utility's generation-related costs. While seeking rate relief from the CPUC, the Utility financed the difference between its wholesale electricity costs and the amount collected through frozen retail rates. By December 31, 2000, the Utility had borrowed more than $3 billion. As of December 31, 2000, the Utility had accumulated a total of approximately $6.9 billion in under-collected wholesale electricity costs and generation-related transition costs. This amount was charged to earnings at December 31, 2000, because the Utility could no longer conclude that such costs were probable of collection through regulated rates.

In January 2001, the CPUC granted an interim rate increase of $0.010 per kWh. This increase, which could not be used to recover past procurement costs, was not sufficient to cover the on-going high wholesale electricity costs then being experienced. As a result of the higher energy prices and the insufficient rate increase, PG&E Corporation's and the Utility's credit ratings deteriorated to below investment grade. These credit downgrades, which occurred on January 16 and 17, 2001, were events of default under one of the Utility's revolving credit facilities and precluded PG&E Corporation's and the Utility's access to the capital markets. Accordingly, the banks stopped funding under the Utility's revolving credit facility. On January 17, 2001, the Utility began to default on maturing commercial paper obligations. In addition, the Utility was no longer able to meet its obligations to generators, qualifying facilities (QFs), the Independent System Operator (ISO), and the Power Exchange (PX), and began making partial payments of amounts owed.

As of January 19, 2001, the Utility had no credit under which it could purchase power for its customers, and generators were only selling to the Utility under emergency actions taken by the U.S. Secretary of Energy. As a result, the State of California authorized the DWR to purchase electricity for the Utility's customers. California Assembly Bill AB 1X was passed on February 1, 2001, authorizing the DWR to enter into contracts for the supply of electricity and to issue revenue bonds to finance electricity purchases, although the DWR indicated that it intended to buy power only at reasonable prices to meet the Utility's net open position, leaving the ISO to purchase the remainder in order to avoid blackouts. (The net open position is the amount of power needed by retail electric customers that cannot be met by utility-owned generation or power under contract to the Utility).

Throughout the energy crisis, the Utility sought relief through various regulatory proceedings and through efforts to reach a negotiated solution with the State of California ("State"). In late March and early April 2001, the CPUC issued a series of decisions that increased the Utility's inability to recover past debts and increased its exposure to significant additional costs. On March 27, 2001, the CPUC ruled on the Utility's November 20, 2000, request for rate relief. This decision made permanent the $0.010 per kWh interim increase authorized in January 2001 and granted an additional $0.030 per kWh (on average) energy surcharge effective immediately, but that would not be included in customer bills until June 2001. The revenue generated by the rate increase was to be used only for electric power procurement costs incurred after March 27, 2001. This decision ordered the Utility to pay the DWR the full generation-related portion of retail rates for every kWh of electricity sold by the DWR without regard to whether overall retail rates were adequate to recover the remainder of the Utility's cost of service. In the same decision, the CPUC adopted an accounting proposal by The Utility Reform Network (TURN), which retroactively restates the way in which transition costs (those costs believed to be uneconomic are discussed further in Note 3 of the Notes to the Consolidated Financial Statements) are recovered. This retroactive change had the effect of extending the rate freeze and reducing the amount of past wholesale power costs that could be eligible for recovery from customers.

Also on March 27, 2001, the CPUC issued a ruling that required the Utility to begin paying the QFs in full and within 15 days of the end of the QF's billing cycle. On April 3, 2001, the CPUC issued a ruling which adopted a methodology for the Utility to reimburse the DWR for power purchases made to meet the Utility's net open position. The Utility believes this ruling, along with other rulings, illegally compels the Utility to make payments to the DWR and QFs without providing adequate revenues for such payments.

The Utility believes that these actions taken by the CPUC are illegal and the Utility has filed for rehearings and appeals with the CPUC, in federal court, and with the Bankruptcy Court. The status of these proceedings is discussed later in this MD&A.

As discussed further in Note 2 of the Notes to the Consolidated Financial Statements, as a result of (1) the failure of the DWR to assume the full procurement responsibility for the Utility's net open position, (2) the negative impact of a CPUC decision that created new payment obligations for the Utility and undermined its ability to return to financial viability, (3) a lack of progress in negotiations with the State of California to provide a solution for the energy crisis, and (4) the adoption by the CPUC of an illegal and retroactive accounting change that would appear to eliminate the Utility's true under-collected wholesale electricity costs, the Utility filed a voluntary petition for relief under the provisions of the Bankruptcy Code on April 6, 2001.

Under Chapter 11, the Utility retains control of its assets and is authorized to operate its business as a debtor-in-possession while being subject to the jurisdiction of the Bankruptcy Court. Subsidiaries of the Utility, including PG&E Funding, LLC (which holds the Rate Reduction Bonds) and PG&E Holdings, LLC (which holds stock of the Utility), are not included in the Utility's petition. Neither PG&E Corporation nor PG&E NEG has declared bankruptcy.

The Utility's Consolidated Financial Statements have been prepared in accordance with the American Institute of Certified Public Accountants' Statement of Position (SOP) 90-7, "Financial Reporting by Entities in Reorganization Under the Bankruptcy Code," and on a going concern basis, which contemplates continuity of operation, realization of assets, and liquidation of liabilities in the ordinary course of business. However, as a result of the filing, such realization of assets and liquidation of liabilities are subject to uncertainty.

Certain claims against the Utility in existence before the filing of its bankruptcy petition are stayed while the Utility continues business operations as a debtor-in-possession. The Utility has reflected its total estimate of all such valid claims on the December 31, 2001, Consolidated Balance Sheets as $11.4 billion of Liabilities Subject to Compromise, and as $3.4 billion of Long-Term Debt. Additional claims or changes to Liabilities Subject to Compromise may arise after the filing date resulting from, among other things, resolution of disputed claims and Bankruptcy Court actions. Payment terms for these amounts will be established through the bankruptcy proceedings. Secured claims also are stayed, although the holders of such claims have the right to ask the Bankruptcy Court for relief from the stay. Secured claims are secured primarily by liens on substantially all of the Utility's assets and by pledged accounts receivable from gas customers. The Bankruptcy Court has approved certain payments and actions necessary for the Utility to carry on its normal business operations (including payment of employee wages and benefits, refunds of certain customer deposits, use of certain bank accounts and cash collateral, payments to QFs, assumption of various hydroelectric contracts with water agencies and irrigation districts, interest on secured debt, and continuation of environmental remediation and capital expenditure programs) and to fulfill certain post-petition obligations to suppliers and creditors.

Through September 5, 2001, the last day for non-governmental creditors to file proofs of claim, approximately $42.1 billion of claims had been submitted. This amount includes claims filed by generators (which the Utility believes have been significantly overstated) and claims filed by financial institutions (which the Utility believes contain significant duplication). The Bankruptcy Court so far has disallowed approximately $9 billion of claims filed by non-governmental entities. In addition, through October 3, 2001, the last day for governmental entities to file proofs of claim, approximately $1.9 billion of claims had been submitted. These include, but are not limited to, contingent environmental claims, claims for federal, state and local taxes, and claims submitted by the DWR for approximately $430 million of energy purchases made on behalf of the Utility's retail customers.

The claims resolution process in bankruptcy involves establishment of the validity of the claim and determination of specifically how the claim is to be discharged. In addition, it is very common to negotiate with creditors to achieve settlement. The Utility intends to explore settlement of claims wherever possible.

On September 20, 2001, the Utility and PG&E Corporation jointly filed with the Bankruptcy Court a proposed plan of reorganization of the Utility under the Bankruptcy Code and a proposed disclosure statement describing the proposed plan. Both the plan of reorganization and the disclosure statement were amended on December 19, 2001, and again on February 4, 2002, in an effort to resolve objections that had been filed by various parties. If the amended Plan is confirmed and becomes effective, the Plan would allow the Utility to restructure its businesses, refinance the restructured businesses, and use the proceeds from the refinancing to pay all valid claims with interest (see Note 2 of the Notes to the Consolidated Financial Statements for a complete description of the Plan).

The Plan, which has been endorsed by the Official Committee of Unsecured Creditors and another group of creditors, is designed to align the businesses under the regulators that best match the business functions. Retail assets would remain under the retail regulator (CPUC) and wholesale assets would be placed under wholesale regulators, the Federal Energy Regulatory Commission (FERC) and the Nuclear Regulatory Commission (NRC). After this alignment, the retail-focused, state-regulated business would be a gas and electric distribution company (Reorganized Utility) representing approximately 70 percent of the book value of the Utility's current assets and having approximately 16,000 employees. The wholesale businesses, which would be federally regulated (as to price, terms, and conditions), would consist of electric transmission (ETrans), interstate gas transmission (GTrans), and generation (Gen).

The Plan proposes that certain other assets of the Utility deemed not essential to operations would be sold to third parties or transferred to Newco Energy Corporation (Newco), a consolidated subsidiary created by the Utility to hold the investments in ETrans, GTrans, and Gen. Additionally, the Utility would declare and, after the assets are transferred to the newly formed entities, pay a dividend of all of the outstanding common stock of Newco to PG&E Corporation. Each of ETrans, GTrans, and Gen would continue to be an indirect wholly owned subsidiary of PG&E Corporation.

The Utility's 18,500 circuit miles of electric transmission lines and cable would be transferred to ETrans, a California company. ETrans would operate as an independent transmission company selling transmission services to wholesale customers (utilities) and to electric generators.

The Utility's 6,300 miles of transmission pipelines and three gas storage facilities would be transferred to GTrans, a California company. GTrans would hold the majority of the land, rights of way, and access rights currently associated with Utility gas transmission pipelines. GTrans would also assume certain continuing contractual obligations currently held by the Utility's gas transmission operation. In addition, the Reorganized Utility would hold a 10- to 15-year transportation and gas storage contract with GTrans.

The Utility's hydroelectric and nuclear generation assets and associated lands, and the power contracts with irrigation districts would be transferred to Gen, a California company. In total, the unit would have approximately 7,100 megawatts (MW) of generation. The facilities would be operated in accordance with all current FERC and Nuclear Regulatory Commission (NRC) licenses. The generating business would sell its power back to the Reorganized Utility under a 12-year contract at a stable, market-based rate.

The Plan, as amended, relies on the FERC and the Bankruptcy Court to authorize certain actions which are outside of management's control. These actions include allowing a shift in jurisdiction of certain of the Utility's assets, approving contracts between and among the newly formed entities, and preempting certain state and local laws. Specifically, the Plan asks the Bankruptcy Court to issue the following orders or make the following findings:

- Approve the Plan, authorizing the Utility to execute, implement, and take all actions necessary or appropriate to give effect to the transactions contemplated by the Plan and the Plan documents;
- Determine that the Utility, PG&E Corporation, and their affiliates are not liable or responsible for any DWR power contracts or purchases of power by the DWR, or any liabilities associated therewith;
- Prohibit the Reorganized Utility from accepting an assignment of the DWR contracts;
- Prohibit the Reorganized Utility from reassuming the net open position unless the Reorganized Utility is found to be creditworthy (as defined in the Plan documents) and a regulatory mechanism exists for the Reorganized Utility to recover its wholesale power purchases;
- Approve the execution of the proposed service and sales contracts between the Reorganized Utility and one or more of the disaggregated entities;
- Find that the CPUC affiliate transaction rules are not applicable to the restructuring transactions;
- Find that the approval of state and local agencies of California, including but not limited to the CPUC, shall not be required in connection with the restructuring transactions because the Bankruptcy Code preempts such state and local laws;
- Find that neither PG&E Corporation nor the Utility is required to comply with certain provisions of the California Corporations Code relating to corporate distributions and the sale of substantially all of a corporation's assets because the Bankruptcy Code preempts such state law;

On February 7, 2002, the Bankruptcy Court issued an order concluding that bankruptcy law does not expressly preempt state law in connection with the implementation of a plan of reorganization. Instead, the Bankruptcy Court interpreted the applicable bankruptcy law to impliedly preempt state law where it has been shown that enforcing the state law at issue would be an obstacle to the accomplishment and execution of the full purposes of the bankruptcy laws. The Bankruptcy Court stated that whether a restructuring; i.e., the disaggregation of the Utility's businesses as proposed in the Plan, is necessary and required for a feasible reorganization, is an issue to be determined at the confirmation hearing.

The Bankruptcy Court provided guidance as to how the Plan could be amended to obtain court approval so that the stage would be set for the "implied preemption confirmation contest." The Plan and disclosure statement will be amended to (1) eliminate express preemption provisions so they can proceed to a confirmation hearing where PG&E Corporation and the Utility intend to show that implied preemption of specified statutes is available to confirm the Plan, and (2) state with specificity the facts demonstrating that the state and the CPUC have waived their sovereign immunity, and, in the event the Bankruptcy Court finds that such immunity has been waived, to provide for declaratory and injunctive relief against the state and the CPUC. If the Bankruptcy Court determines that such sovereign immunity has not been waived, the Bankruptcy Court indicated in its February 7, 2002, decision that it would still be able to enforce its confirmation order under certain circumstances. PG&E Corporation and the Utility must file an amended Plan and disclosure statement by March 7, 2002. Objections to the amended Plan and disclosure statement must be filed with the Bankruptcy Court by March 19, 2002. The Bankruptcy Court has scheduled a hearing for March 26, 2002, to consider the adequacy of the amended disclosure statement and to resolve objections.

The CPUC has filed with the Bankruptcy Court a term sheet depicting its alternative plan of reorganization on February 13, 2002. The CPUC's term sheet does not call for realignment of the Utility's business and provides for the continued regulation of all of the Utility's current operations by the CPUC. Other significant components of the CPUC's plan include:

- Prohibits the Utility from declaring or making cash distributions to PG&E Corporation (including by way of dividends and stock repurchases) through 2003;
- Provides for shareholders to contribute a projected $1.2 billion from the return on rate base for the period December 1, 2001, through January 3, 2003;
- Assumes the Utility will satisfy FERC's creditworthiness requirements and will resume purchasing the net open position no later than January 2003;
- Keeps current Utility rates in effect until no later than January 31, 2003, the assumed effective date of the CPUC plan. After all debts are paid in full, or reinstated, the CPUC would establish a cost of service rate structure;
- Establishes a Litigation Trust for the benefit of the Utility's customers which would be funded with (1) cash from the Utility in an amount to be determined, and (2) proceeds from settlement of various claims and causes of action including: (a) claims against PG&E Corporation (See Order Instituting Investigation (OII) into Holding Company Activities and Attorney General Complaint in Regulatory Matters), (b) refund claims from electric generators pending before FERC, if any, (c) other claims against electric generators, and (d) up to the first $1.75 billion of proceeds from the federal lawsuit filed by the Utility against the CPUC (See Federal Lawsuit in Regulatory Matters);
- Assumes all valid claims (together with post petition interest at the lowest non-default contract rate, or if no contract or non-default rate exists, then the federal judgment rate) will be satisfied in full through a combination of cash (estimated to be $6.9 billion by January 31, 2003), and reinstatement of certain of the Utility's long-term indebtedness and other obligations (approximately $5.8 billion); and
- Assumes the Utility will obtain a credit facility to fund capital expenditures, working capital, and if necessary, distributions to unsecured creditors.

The CPUC's proposed timeline for its alternate plan provides for confirmation hearings to begin on or before September 16, 2002 and for the plan to become effective on or before January 31, 2003.

PG&E Corporation and the Utility do not believe the CPUC's plan is credible because it overstates the available cash, understates the debt and other obligations, and undermines the Utility's ability to invest in electrical system reliability. PG&E Corporation and the Utility also do not believe the CPUC's plan will restore the Utility to investment grade status when the plan becomes effective. On February 27, 2002 the Bankruptcy Court decided to permit the CPUC to formally file its proposed plan. The CPUC must submit its alternative plan by April 15, 2002.

PG&E Corporation and the Utility are unable to predict whether the Bankruptcy Court will confirm the Plan, whether the Bankruptcy Court will confirm the CPUC's alternative plan, or whether other parties may file an alternative plan of reorganization after June 30, 2002 when the period during which only the Utility (except the CPUC) may file a proposed plan will expire. Consideration of alternative plans could cause delays in the Plan's current schedule. PG&E Corporation and the Utility cannot predict what will be in these other parties' plans or whether they will be confirmed by the Bankruptcy Court. Further, assuming the Bankruptcy Court confirms the Plan, implementation may be impacted by appeals, which could also cause delays. Accordingly, the filing for bankruptcy protection and the related uncertainty around the plan of reorganization that is ultimately adopted will have a significant impact on the Utility's future liquidity and results of operations. The Utility is not able at this time to predict the outcome of its bankruptcy case, or the effect of the Chapter 11 reorganization process on the claims of the creditors of the Utility or the interests of the Utility's preferred security holders. However, the Utility believes, based on information presently available to it, that cash and cash equivalents on hand at December 31, 2001, of $4.3 billion and cash available from operations will provide sufficient liquidity to allow it to continue as a going concern through 2002.

PG&E Corporation

The liquidity and financial condition crisis faced by the Utility also negatively impacted PG&E Corporation. Through December 31, 2000, PG&E Corporation funded its working capital needs primarily by drawing down on available lines of credit and other short-term credit facilities. At December 31, 2000, PG&E Corporation had borrowed $185 million against its five-year revolving credit agreement and had issued $746 million of commercial paper. On January 16 and 17, 2001, PG&E Corporation's credit ratings were downgraded along with the Utility's ratings to below investment grade, and the banks refused any additional borrowing requests and terminated their remaining commitments under existing credit facilities. Commencing January 17, 2001, PG&E Corporation began to default on its maturing commercial paper obligations.

On March 1, 2001, PG&E Corporation refinanced its debt obligations with $1 billion in aggregate proceeds from two term loans under a common credit agreement with General Electric Capital Corporation (GECC) and Lehman Commercial Paper Inc. (LCPI). The obligations under the credit agreement are secured by a pledge of PG&E Corporation's interest in PG&E NEG. The credit agreement also provided GECC and LCPI an option to purchase for $1.00 up to a 3 percent ownership interest in PG&E NEG, depending upon how long the loans are outstanding. In accordance with the credit agreement, the proceeds, together with other PG&E Corporation cash, were used to pay $501 million in commercial paper (including $457 million of commercial paper on which PG&E Corporation had defaulted), $434 million in borrowings under PG&E Corporation's long-term revolving credit facility, and $109 million to PG&E Corporation shareholders of record as of December 15, 2000, in satisfaction of a defaulted fourth quarter 2000 dividend. Further, approximately $99 million was used to prepay the first year's interest under the credit agreement and to pay transaction expenses associated with the debt restructuring.

In November 2001, and March 2002, PG&E Corporation signed agreements to amend its current $1 billion aggregate term loan credit facility with GECC and LCPI and their assignees. The original debt obligation, entered into on March 1, 2001, permitted PG&E Corporation to extend the term of the credit facility, which would otherwise expire on March 1, 2003, for an additional year. The amendments, provide for two additional one-year extensions to the term of the credit facility contingent upon PG&E Corporation making a principal payment of $308 million by June 3, 2002, so that the termination date could be extended to March 2, 2006. As a condition for the exercise of each of the one-year extensions, PG&E Corporation must pay a fee of 3 percent of the then-outstanding balance and also issue to the lenders additional options equal to approximately 1 percent of the common stock of PG&E NEG. If PG&E Corporation extends the term from March 1, 2003, using the initial extension, the fee will be 2 percent of the then-outstanding balances for each six-month period.

The credit agreement with GECC and LCPI provides that a failure to comply with financial covenants will constitute an event of default, after applicable grace periods. These covenants include, among other things, the requirement that PG&E NEG maintain an investment grade credit rating and a ratio of fair market value to the aggregate amount of principal outstanding under the loan of at least 2:1, and that PG&E Corporation maintain a cash reserve of at least 15 percent of the loan balance until March 2, 2004, and 10 percent thereafter, unless interest is prepaid. In addition, failure of PG&E NEG to maintain at least a 1.25:1 ratio of fair market value to loan balance would constitute an immediate event of default and result in acceleration of the loan.

PG&E Corporation itself had cash and short-term investments of $348 million at December 31, 2001, and believes that the funds will be adequate to maintain PG&E Corporation's continuing operations through 2002. In addition, PG&E Corporation believes that it and its non-CPUC regulated subsidiaries are protected from the bankruptcy of the Utility.

PG&E NEG

The national markets in which PG&E NEG participates are experiencing the first sustained downturn in the electric power commodity business cycle since electric deregulation began in the mid-1990s. Price spikes beginning in 1997 and 1998 culminated in peak prices in 2000 and early 2001. New supply additions begun under the high-price period, combined with a softening economy, have resulted in projected excess energy supply. The price of electricity minus the cost of fuel, or spark spread, available in most regional wholesale energy markets has declined recently, and prices and spark spreads in the forward markets in which PG&E NEG transacts much of its business for its generating portfolio have declined as well.

On December 2, 2001, a major participant in the energy business, Enron Corp. (Enron), filed for protection under Chapter 11 of the U.S. Bankruptcy Code (Enron Bankruptcy). The Enron Bankruptcy had little impact on the energy commodity markets which have remained liquid and efficient. Although Enron was a significant participant in the energy trading business, a large portion of Enron's transactions was purely financial, thereby minimizing impacts on the physical energy markets. In addition, significant reporting in the public press during the months preceding the Enron Bankruptcy enabled many counterparties, including PG&E NEG, to reduce their exposure to Enron.

In contrast to the minimal impact on the energy trading markets, the Enron Bankruptcy exacerbated uncertainty in the capital markets for energy companies, which was initially triggered by the California energy crisis and the Utility's bankruptcy. Analysts are now expecting improved accounting and reporting standards, and the rating agencies are reviewing the credit quality and credit ratings of many energy companies. Moody's Investors Service (Moody's) has particularly focused on rating triggers and has indicated that it is revising its view of debt to total capitalization levels and other key credit criteria when assigning credit ratings. Continued capital market uncertainty or any lowering of PG&E NEG's credit rating would adversely impact PG&E NEG's access to capital or its cost to access capital and could impede PG&E NEG's growth plans and cash liquidity positions.

A lower level of economic activity may result in a decline in energy consumption and new electric supply additions begun during more robust economic conditions are beginning to commence operation. The combination of decreased consumption and increased supply may result in excess supply and declining operating margins for electric generators. Furthermore, these same factors may result in lower price volatility for energy products, potentially reducing profits from energy trading activities.

In response to these market changes, PG&E NEG may defer, cancel, sell joint ventures in, or otherwise dispose of some or all of its projects in development and the equipment associated with those projects. In connection with PG&E NEG's current revised development plans, it has restructured some of the equipment purchase and option commitments to provide additional flexibility in payment terms and delivery schedules to better accommodate the potential delay, swap, or sale of generation projects in development. If PG&E NEG determines to further defer or cancel a project, it may create a mismatch between equipment delivery schedules and development plans. If equipment delivery schedules cannot be adjusted, PG&E NEG may be compelled to choose between paying for equipment in which it would have to store for future use or terminating its commitment to purchase such equipment. If PG&E NEG decides to terminate equipment, then it would incur termination costs to the equipment vendors consisting of amounts shown on the balance sheet plus additional cash payments, if any, due upon termination (Termination Costs). PG&E NEG's exposure for these Termination Costs gradually increases over time. PG&E NEG's cash exposure for Termination Costs would be offset by amounts expended for the equipment through the date of termination.

In December 2000, and in January and February 2001, PG&E Corporation and PG&E NEG completed a corporate restructuring of PG&E NEG, known as a "ringfencing" transaction. The ringfencing involved the creation or use of limited liability companies as intermediate owners between a parent and its subsidiaries. The intermediate owners, which are consolidated in the accompanying financial statements are: PG&E National Energy Group, LLC which owns 100 percent of the stock of PG&E NEG, PG&E GTN Holdings LLC which owns 100 percent of the stock of PG&E GTN, and PG&E Energy Trading Holdings LLC which owns 100 percent of the stock of PG&E Energy Trading Holdings Corporation. In addition, in March 2001, PG&E NEG's organizational documents were modified to include the same structural elements as those of these new companies. The organizing documents of these new companies require unanimous approval of their respective boards of directors, including at least one independent director, before they can (1) consolidate or merge with any entity, (2) transfer substantially all of their assets to any entity, or (3) institute or consent to bankruptcy, insolvency, or similar proceedings or actions. The new companies may not declare or pay dividends unless the respective boards of directors have unanimously approved such action, and the company meets specified financial requirements. After the ringfencing structure was implemented, two independent rating agencies, Standard & Poor's (S&P) and Moody's, reaffirmed investment grade ratings for PG&E GTN and PG&E Gen LLC and issued investment grade ratings for PG&E NEG. S&P also issued an investment grade rating for PG&E ET.

STATEMENTS OF CASH FLOWS FOR 2001, 2000, AND 1999

PG&E Corporation normally funds investing activities from cash provided by operations after capital requirements, and, to the extent necessary, external financing. PG&E Corporation's policy is to finance its investments with a capital structure that minimizes financing costs, maintains financial flexibility, and, with regard to the Utility, complies with regulatory guidelines. However, the Utility is currently operating as a debtor-in-possession under Chapter 11 of the Bankruptcy Code. While certain pre-petition debts are stayed, the Utility does not have access to external funding from the capital markets. Additionally, the Utility is in default under its credit facilities, commercial paper, floating rate notes, senior notes, pollution control reimbursement agreements, and medium-term notes resulting from its failure to pay certain of its obligations. The event of default under each security has been stayed in accordance with the bankruptcy proceedings. The Utility has been making the capital investment in its infrastructure out of cash on hand under supervision of the Bankruptcy Court. It is uncertain whether the Utility will be able to continue to make such necessary capital investment in the future. See Note 2 of the Notes to the Consolidated Financial Statements for a discussion of the Chapter 11 bankruptcy filing.

PG&E Corporation – Consolidated

Cash Flows from Operating Activities

Net cash provided by PG&E Corporation's operating activities totaled $5,300 million, $705 million, and $2,302 million in 2001, 2000, and 1999, respectively. The increase between 2001 and 2000 is primarily attributed to the Utility's pre-petition obligations being stayed under Chapter 11 of the Bankruptcy Code, and deliveries on previously held trading positions at PG&E NEG. The decrease in cash flows from operating activities between 2000 and 1999 is primarily attributed to the Utility's additional electric procurement costs associated with the California energy crisis, with no regulated rate recovery.

Cash Flows from Investing Activities

Cash used in investing activities was $2,900 million, $1,690 million, and $234 million in 2001, 2000, and 1999, respectively.

During 2001, 2000, and 1999, PG&E Corporation used $2.7 billion, $2.3 billion, and $1.7 billion, respectively, for upgrades and expansions of its facilities in operation or under construction. These capital expenditures were partially offset by the 1999 divestitures of generation facilities at the Utility and by the completed sales of the PG&E ES and PG&E GTT business units in 2000. In 2000, PG&E Corporation sold its energy services retail business for $85 million and its value-added services business and various other assets for $18 million. PG&E NEG received $306 million, which included a working capital adjustment, for the sale of PG&E GTT. The sale also included the purchaser's assumption of liabilities associated with PG&E GTT and debt having a book value of $564 million. In 1999, the Utility received proceeds of $1,014 million from the sale of generation facilities.

Cash Flows from Financing Activities

PG&E Corporation net cash provided (used) by financing activities totaled $591 million, and $3,075 million and $(1,940) million in 2001, 2000, and 1999, respectively. The Utility and PG&E NEG financing activities are discussed below. In 2001, PG&E Corporation netted $906 million in proceeds from a loan agreement, which, together with cash on hand and from cash operating activities, was used to repay defaulted commercial paper, other loans, and the $109 million in defaulted fourth quarter 2000 dividends. On a consolidated basis, net cash provided by financing activities in 2000 was achieved principally through borrowings under credit facilities and the issuance of short-term and long-term debt needed to fund energy purchases. Overall, net cash used by financing activities in 1999 was used principally to retire debt, repurchase outstanding common stock, and pay dividends.

During 2001, 2000, and 1999, PG&E Corporation issued $15 million, $65 million, and $54 million of common stock, respectively, primarily through the Dividend Reinvestment Plan and the Stock Option Plan component of the Long-Term Incentive Program. During 2001, 2000, and 1999, PG&E Corporation paid dividends on its common stock of $109 million, $436 million, and $465 million, respectively.

During 2001, 2000, and 1999, PG&E Corporation repurchased $0.5 million, $2 million, and $693 million of its common stock, respectively. The 1999 repurchases were executed through separate accelerated share repurchase programs. As of December 31, 1997, the Board of Directors had authorized the repurchase of up to $1.7 billion of PG&E Corporation's common stock on the open market or in negotiated transactions. In February 1999, PG&E Corporation used the remaining funds available under this authorization to purchase 16.6 million shares at a total cost of $531 million. A subsidiary of PG&E Corporation made this repurchase, along with subsequent stock repurchases. The stock held by the subsidiary is treated as treasury stock and is reflected as Stock Held by Subsidiary on the Consolidated Balance Sheets of PG&E Corporation.

In October 1999, the Board of Directors of PG&E Corporation authorized the repurchase of an additional $500 million of PG&E Corporation's common stock on the open market. This authorization supplemented the approximately $40 million remaining from the amount previously authorized. The authorization for share repurchase extended through September 30, 2001. As of December 31, 1999, PG&E Corporation had, through its wholly owned subsidiary, repurchased an additional 7.2 million shares, at a cost of $159 million, under this authorization. PG&E Corporation is precluded by its March 2, 2001, credit agreement with GECC and LCPI from repurchasing any more of its common stock until the loans are repaid.

Utility

The following section discusses the Utility's significant cash flows from operating, investing, and financing activities for the three-year period ended December 31, 2001.

Cash Flows from Operating Activities

Net cash provided by the Utility's operating activities increased to $4,765 million in 2001 from $555 million in 2000. The increase is due to the Utility's pre-petition obligations being stayed under the provisions of Chapter 11 of the Bankruptcy Code (see Note 2 of the Notes to the Consolidated Financial Statements), generation-related revenues exceeding generation-related costs, and the receipt of the 2000 income tax refund of $1.1 billion.

The decrease of $1,625 million between 1999 and 2000 is attributable to the California energy crisis and the significant deterioration of the Utility's financial condition, primarily caused by the electric procurement costs of $6,465 million. These costs have not been recovered from ratepayers.

Cash Flows from Investing Activities

The primary uses of cash from investing activities were additions to property, plant and equipment. While the Utility is in Chapter 11, these expenditures will be funded from cash provided by operating activities. The Utility's estimated capital spending for 2002 is $1,556 million. The Utility's capital expenditures were $1,343 million, $1,245 million, and $1,181 million for the years ended December 31, 2001, 2000, and 1999, respectively.

During 1999, the Utility sold three fossil-fueled generation facilities and its geothermal generation facilities. These sales closed in April and May 1999, respectively, and generated proceeds of $1,014 million.

Cash Flows from Financing Activities

Net cash used by financing activities in 2001 was $430 million, reflecting repayment of long-term debt of $401 million, and net repayments under credit facilities and short-term borrowings of $28 million.

While the Utility's bankruptcy case is pending, the Utility is prohibited from paying pre-petition obligations without permission from the Bankruptcy Court. Before the Utility filed its petition, it had paid $18 million related to the maturity of the Utility's various medium-term notes, made net repayments under credit facilities and short-term borrowings of $28 million, and paid $93 million of maturing mortgage bonds. The Utility is current with all interest and sinking fund payments on its mortgage bonds. The Utility also paid $290 million related to the maturity of the Rate Reduction Bonds held by the Utility's wholly owned subsidiary. On February 27, 2002, the Bankruptcy Court approved the Utility's payment of $333 million of mortgage bonds maturing in March 2002.

The Utility maintained a $1 billion credit facility, which is due to expire in November 2002. The unused portion of this facility was cancelled by the bank lending group on January 23, 2001. This facility was previously used to support the Utility's commercial paper program and other liquidity requirements. As of December 31, 2001, the Utility had drawn, and had outstanding, $938 million under this facility to repay maturing commercial paper. In addition, the total defaulted commercial paper outstanding as of December 31, 2001, formerly backed by both this and another now-cancelled facility, was $873 million.

Due to the bankruptcy filing, the Utility is unable at this time to repay its unsecured pre-petition creditors. The Utility has not made interest payments on the following unsecured debt: medium-term notes, $680 million of senior notes, $1,240 million floating rate notes, commercial paper, bank loans, and other unsecured debt. The Utility has not made principal payments on $1,363 million of unsecured debt that matured from April 2001 through December 2001. The Utility is accruing interest on all unpaid debt obligations and compounding interest at interest rates described in the Plan.

The Utility's pollution control loan agreements are primarily secured by irrevocable letters of credit (LOC). As a result of the voluntary petition for Chapter 11, the Utility is in default under the credit providers' reimbursement agreements. Consequently, $454 million of the pollution control loan agreements were declared due and payable, and were funded by drawdowns on the LOCs. Interest payments are current on the remaining $814 million of pollution control loan agreements.

Net cash provided by financing activities in 2000 was $1,937 million, primarily due to net borrowings under the credit facilities and short-term borrowings of $2,630 million and five-year fixed-rate note issues of $680 million, partially offset by the repayment of long-term debt of $597 million, common stock repurchased of $275 million, and dividends paid of $475 million.

The Utility drew on its credit facility in the amount of $614 million and issued commercial paper of $776 million in 2000. Also, in November 2000, the Utility issued $1,240 million of 364-day floating rate notes.

The Utility's long-term debt that either matured, was redeemed, or was repurchased during 2000 totaled $597 million. Of this amount, (1) $110 million related to the maturity of its 6.63 percent and 6.75 percent mortgage bonds, due June 1, and December 1, 2000, respectively, (2) $81 million related to the Utility's repurchase of various pollution control loan agreements, (3) $113 million related to the maturity of the Utility's various medium-term notes, (4) $3 million related to the other scheduled maturities of long-term debt, and (5) $290 million related to maturity of Rate Reduction Bonds.

In April 2000, a subsidiary of the Utility repurchased from PG&E Corporation 11.9 million shares of its common stock at a cost of $275 million in order to maintain its authorized capital structure. During 2000 and 1999, the Utility did not redeem or repurchase any of its preferred stock.

Net cash used by financing activities in 1999 was $2,256 million and resulted from net repayments under the credit facilities and short-term borrowings of $219 million, repayment of long-term debt of $672 million, common stock repurchased of $926 million, and dividends paid of $440 million.

The Utility's long-term debt that either matured, was redeemed, or was repurchased during 1999 totaled $672 million. Of this amount, (1) $290 million related to the Rate Reduction Bonds maturing, (2) $135 million related to the Utility's repurchase of mortgage and various other bonds, (3) $147 million related to the maturity of various Utility mortgage bonds, and (4) $100 million related to the maturities and redemption of various of the Utility's medium-term notes and other debt.

In December 1999, 7.6 million shares of the Utility's common stock, with an aggregate purchase price of $200 million, were purchased by a subsidiary of the Utility. These repurchases are reflected as Common Stock Held by Subsidiary on the Consolidated Balance Sheets of the Utility. Earlier in 1999, the Utility repurchased from PG&E Corporation and cancelled 20 million shares of its common stock for an aggregate purchase price of $726 million, in order to maintain its authorized capital structure.

PG&E NEG

PG&E Energy and PG&E Pipeline business sectors require substantial amounts of liquidity and capital resources to support construction, working capital, and counterparty credit requirements. PG&E NEG's strategy is to finance operations using a combination of funds from operations, equity, long-term debt (secured directly by those assets without recourse to other entities), long-term corporate borrowings in the capital markets, operating leases and short and medium term bank facilities that provide working capital, letters of credit and other liquidity needs. During 2001, PG&E NEG took steps to enhance its liquidity and therefore at December 31, 2001, PG&E NEG had $725 million in cash and approximately $800 million available in unused credit lines.

Neither PG&E NEG nor PG&E Corporation require approval of lenders to sell to third parties all or a portion of the equity of a number of lower level subsidiaries, including those holding advanced development projects, so long as PG&E NEG retains the proceeds as cash, uses the proceeds to pay down debt or reinvests the proceeds in the business. Options that PG&E NEG is currently evaluating for raising equity include: a private placement of common or preferred equity, the sale of all or a portion of certain projects in operation or development, and the issuance of equity in an entity that holds a selected group of generating projects, primarily including projects currently in advanced development. At present, PG&E NEG is unable to sell equity securities in the SEC registered public markets due to market conditions or circumstances of the Utility and PG&E Corporation.

Funds from operations come from distributions from PG&E NEG's subsidiary companies. Cash flow distributions from subsidiaries are subject to various debt covenants, organizational by-laws, and partner approvals that can restrict these entities from distributing cash to PG&E NEG unless, among other things, debt service, lease obligations, and any applicable preferred payments are current, the applicable subsidiary or project affiliate meets certain debt service coverage ratios, a majority of the participants approve the distribution, and there are no events of defaults. In addition, the subsidiaries that own PG&E NEG's natural gas transmission facilities and its energy trading businesses have been "ringfenced" and cannot pay dividends unless the subsidiary's board of directors, or board of control, including its independent director, unanimously approves the dividend payment, and the subsidiary has either a specified investment grade credit rating or meets a consolidated interest coverage ratio of greater than or equal to 2.25 to 1.00 and a consolidated leverage ratio less than or equal to 0.70 to 1.00.

Cash Flows from Operating Activities

During 2001, PG&E NEG generated net cash from operating activities of $405 million. Net cash from operating activities before changes in working capital accounts and price risk management assets and liabilities was $125 million. This increase was principally due to the improved results of operations in 2001 offset by the timing of deferred tax benefits and lower distributions from unconsolidated affiliates. Net cash inflow related to the change in inventories, prepaid expenses, deposits, restricted cash, and other was $83 million, while the change in accounts receivables, accounts payables, and accrued liabilities increased cash flow by $42 million. Change in price risk management assets and liabilities increased cash flow by $155 million. Operating cash flows include payments of $81 million under power purchase agreements, a portion of which is offset by cash receipts from long-term receivables reflected in investing activities.

During 2000, PG&E NEG generated net cash from operating activities of $172 million. Net cash from operating activities before changes in working capital accounts and price risk management assets and liabilities was $267 million. This increase was principally due to the timing of deferred tax benefits and higher distributions from unconsolidated affiliates. Net cash related to the change in inventories, prepaid expenses, deposits, restricted cash, and other was reduced by $139 million, while the change in accounts receivables, accounts payables, and accrued liabilities increased cash flow by $65 million. The change in price risk management assets and liabilities decreased cash flow by $21 million. Operating cash flows include payments of $75 million under power purchase agreements, a portion of which is offset by cash receipts from long-term receivables reflected in investing activities.

During 1999, PG&E NEG generated net cash from operations of $88 million. Net cash from operating activities before changes in working capital accounts and price risk management assets and liabilities was $198 million. This increase was principally due to improved operations offset by the timing of deferred tax benefits. Net cash related to the change in inventories, prepaid expenses, deposits, restricted cash, and other was an increase of $109 million, while the change in accounts receivables, accounts payables, and accrued liabilities decreased cash flow by $98 million. The change in price risk management assets and liabilities decreased cash flow by $121 million. Operating cash flows include payments of $66 million under power purchase agreements, a portion of which is offset by cash receipts from long-term receivables reflected in investing activities.

Cash Flows from Investing Activities

During 2001, PG&E NEG used net cash of $1.6 billion for investing activities which were primarily attributable to capital expenditures associated with generating projects in construction and advanced development and turbine and other equipment commitments.

During 2000, PG&E NEG used net cash of $864 million for investing activities. Primary cash outflows from investing activities were for capital expenditures of $900 million and the acquisition of Attala Generating Company LLC (Attala) for $311 million in cash. These outflows were partially offset by the receipt of $442 million in proceeds from sales of assets and equity investments.

During 1999, PG&E NEG used net cash of $180 million for investing activities. Investing activities in 1999 consisted principally of $267 million in capital expenditures, partially offset by proceeds from the sale of assets or equity investments of $90 million.

Cash Flows from Financing Activities

During 2001, PG&E NEG entered into a series of financial transactions to support the construction and acquisition of new assets, finance equipment deposits, refinance existing indebtedness, and provide liquidity and working capital for energy trading and other business activities. These credit facilities have been reviewed by S&P and Moody's, in establishing and maintaining the credit ratings of PG&E NEG and its subsidiaries.

PG&E NEG and its subsidiaries maintain the following credit facilities, and have undertaken the following major financings.

On May 22, 2001, PG&E NEG completed an offering of $1 billion in senior unsecured notes (Senior Notes) and received net proceeds of approximately $972 million after bond debt discount and note issuance costs. PG&E NEG has used a portion of the net proceeds and intends to use the balance of the net proceeds to pay down existing revolving debt, to fund investment in generating facilities and pipeline assets, and for working capital requirements and other general corporate requirements. These Senior Notes bear interest at 10.375 percent per annum and mature on May 16, 2011.

In May 2001, PG&E NEG established a revolving credit facility of up to $280 million to fund turbine payments and equipment purchases associated with its generation facilities. The facility is due to be fully repaid on December 31, 2003. As of December 31, 2001, PG&E NEG had borrowed $221 million against this total borrowing capacity.

PG&E NEG maintains various revolving credit facilities at subsidiary levels which currently are available to fund its capital and liquidity needs. PG&E NEG's generation operation maintains a $100 million revolving credit facility which expires in September 2003. PG&E GTN maintains a $100 million revolving credit facility that expires in May 2002. Outstanding loans on these two facilities are charged London Interbank Offering Rate (LIBOR)-based interest rates, with an interest rate spread over LIBOR tied to the credit rating of the applicable subsidiary and the amount drawn on the facility. As of December 31, 2001, PG&E NEG had borrowed $160 million against its $200 million borrowing capacity under these facilities.

In August 2001, PG&E NEG arranged a $1.25 billion working capital and letter of credit facility consisting of $500 million with a two-year term and $750 million with a 364-day term maturing in August 2003 and August 2002, respectively. PG&E NEG uses this facility to provide working capital and liquidity to its businesses, for letters of credit to fund development and early phase construction expenditures, and for other general corporate purposes. Outstanding loans under this facility are charged LIBOR-based interest rates and an interest rate spread over LIBOR tied to PG&E NEG's credit ratings. On December 31, 2001, $115 million of letters of credit were outstanding under this facility (with a maximum capacity to issue $650 million) and borrowings of $330 million were outstanding under this facility.

In September 2001, PG&E NEG closed a $69.4 million non-recourse secured five-year project financing for the construction of the Plains End generating project in Colorado. As of December 31, 2001, there was $23.3 million outstanding under this financing. As of December 31, 2001, PG&E NEG had invested $16.2 million in the Plains End project and had a payment guarantee to the construction contractor of $5 million.

In December 2001, PG&E NEG closed a new $1.075 billion five-year non-recourse project financing for the GenHoldings I, LLC portfolio of projects secured by the Millennium, Harquahala, and Athens projects. PG&E NEG has provided a guarantee of the equity commitment for these projects of $701 million, of which $251 million remains to be contributed. The equity is scheduled to be funded pro-rata with the debt at a 60/40 debt/equity ratio, although equity infusions could be triggered earlier by a downgrade of PG&E NEG's unsecured debt to below investment grade by both S&P and Moody's, or the failure to meet certain debt covenants of the unsecured debt. This financing was used to reimburse PG&E NEG and repay debt to pay for a portion of the construction costs already incurred on these projects, and will be used to fund a portion of the balance of the construction costs through completion. As of December 31, 2001, there was $449.5 million outstanding under this financing. PG&E NEG has contributed $450 million of equity-in-kind in the form of the Millennium project and partial construction of the Athens and Harquahala projects to GenHoldings I, LLC, and is committed to contribute additional equity during the construction period, which is projected to be completed by the third quarter of 2003.

Cash flow from financing activities by PG&E NEG were $1,140 million, $1,202 million, and $152 million in 2001, 2000, and 1999, respectively. Net cash provided by financing activities in 2001 related to the net proceeds received from the issuance of the Senior Notes partially offset by repayments of amounts borrowed under credit facilities.

During 2000, net cash provided by financing activities was $1,202 million. Net cash provided by financing activities resulted primarily from capital contributions by PG&E Corporation of $608 million, partially offset by distributions of $106 million and other items.

During 1999, net cash provided by financing activities was $152 million. This amount includes borrowings and debt issuances totaling $463 million. PG&E NEG declared and paid to PG&E Corporation a dividend of $111 million in 1999. During 1999, PG&E NEG also repaid a total of $269 million of long-term debt, including PG&E GTT mortgage bonds and senior notes.

COMMITMENTS AND CAPITAL EXPENDITURES

PG&E Corporation has numerous outstanding contractual obligations and commitments which include those for capital spending, debt principal payment provisions, electricity, gas purchasing transportation and pipeline capacity, nuclear fuel components, operating leases, tolling agreements, turbine purchases, project financing, and guarantees with counterparties. At December 31, 2001, the following table provides information about PG&E Corporation's contractual obligations and commitments.

	2002	2003	2004	2005	2006	Thereafter
			(dollars in millions)			
Utility:						
Power purchase agreements[1]	$1,513	$1,473	$1,453	$1,436	$1,336	$8,404
Natural gas supply and transportation	358	110	88	77	21	5
Operating leases	11	11	12	12	11	18
Nuclear fuel	81	35	34	12	14	11
Long-term debt:						
Liabilities not subject to compromise:						
Fixed rate principal obligations	333	281	310	290	—	2,138
Average interest rate	7.88%	6.25%	6.25%	5.89%	—%	7.25%
Liabilities subject to compromise:						
Fixed rate principal obligations	134	41	54	696	1	261
Average interest rate	7.71%	6.38%	7.51%	9.56%	9.45%	5.96%
Variable rate principal obligations	349	265	—	—	—	—
Rate reduction bonds	290	290	290	290	290	290
Average interest rate	6.30%	6.36%	6.42%	6.42%	6.44%	6.48%
PG&E NEG:						
Construction commitments	1,109	202	6	—	—	—
Tolling agreements	50	135	191	204	201	3,461
Turbine and equipment purchases	255	211	208	324	309	1,522
Fuel supply and natural gas transportation agreements	126	113	107	98	92	483
Power purchase agreements	252	255	261	262	265	1,973
Operating leases	72	70	79	79	80	895
Other	31	24	17	18	20	134
Long-term debt:						
Variable rate obligations	14	842	31	41	47	999
Fixed rate obligations	34	6	—	250	1	1,157
Average interest rate	5.89%	7.49%	8.28%	8.64%	8.86%	8.94%
PG&E Corporation:						
Long-term debt	—	1,000	—	—	—	—

(1) The amounts in the table include estimates of amounts that will be paid to QFs under various agreements where terms are being renegotiated as a result of the Utility's bankruptcy.

Utility

The Utility has contractual commitments for the supply of electricity and gas. Under current CPUC regulations, electric energy and capacity are provided by independent power producers that are QFs, irrigation districts, and water agencies. Natural gas is provided by gas suppliers in the western U.S. under contracts of varying lengths, and transportation to California is provided under long-term supply and transportation service contracts with various Canadian and U.S. interstate pipeline companies. In addition, the Utility has purchase agreements for nuclear fuel components and services for use in its Diablo Canyon Nuclear Power Plant.

As a result of the California energy crisis and the Utility's bankruptcy filing, a number of QFs requested the Bankruptcy Court to either terminate their contracts requiring them to sell power to the Utility, or have the contracts suspended for the summer of 2001 so the QFs could sell power at market-based rates. In July 2001, the Utility signed five-year agreements with 197 of its QFs, ensuring the Utility and its customers would receive a reliable supply of electricity at an average energy price of $0.054 per kWh. Under the terms of these assumption agreements, the Utility will assume the pre-petition debt on these 197 QF contracts, totaling $845 million, on the effective date of the plan of reorganization. The total amount the Utility owed to QFs when it filed for bankruptcy protection was approximately $1 billion. The agreements represent 85 percent of debt owed to QFs. For certain of these QFs, if the effective date has not occurred by July 15, 2003, the Utility will pay 2 percent of the principal amount of the pre-petition debt per month until the effective date of the Utility's plan of reorganization or until July 15, 2005, when it will pay the remaining pre-petition debt.

In December 2001 and January 2002, the Bankruptcy Court approved supplemental agreements entered into between the Utility and several QFs to resolve the issue of the applicable interest rate to be applied to the pre-petition debt. The supplemental agreements modify the assumption agreements by (1) setting the interest rate for pre-petition debt at 5 percent per annum; (2) providing for a "catch-up payment" of all accrued and unpaid interest (calculated from the date of default through December 3, 2001) that was paid on December 31, 2001, and (3) providing for an accelerated payment of the principal amount of the pre-petition debt (and interest thereon) in 12 equal monthly payments of principal (and interest thereon) commencing on December 31, 2001, and continuing through November 30, 2002, or, in the event the effective date of the plan of reorganization occurs before the last monthly payment is made, the remaining unpaid principal and accrued but unpaid interest thereon, shall be paid in full on the effective date. The Utility believes that, similar to the experience with the assumption agreements, a large number of the QFs will also wish to enter into similar supplemental agreements.

In addition to the contractual obligations and commitments disclosed above, capital expenditures are expected to be $1,556 million in 2002. In addition, the Utility is required to pass-through certain generation-related revenues to the DWR. These revenues are based on rates established by the CPUC and volumes delivered by the DWR for the Utility's net open position.

The Utility believes that its contractual cash obligations will be met primarily through cash from operations and future financings obtained as a result of the plan of reorganization. For additional discussion of the Utility's commitments, see Note 15 of the Notes to the Consolidated Financial Statements.

PG&E NEG

The projects that PG&E NEG develops typically require substantial capital, and PG&E NEG has made a number of firm commitments associated with its planned growth of owned and controlled generating facilities, as well as its pipelines. These include commitments for projects under construction, commitments for the acquisition and maintenance of equipment needed for projects under development, payment commitments for tolling arrangements, and forward sale and purchase commitments associated with energy marketing and trading activities.

Construction Commitments

PG&E NEG currently has six projects under construction. The construction commitments generally relate to facility engineering, construction and procurement, and other related contracts.

Turbine Purchase Commitments and Long-Term Service Agreements

To support its development program, PG&E NEG has contractual commitments and options for turbines and related equipment. Most significantly, PG&E NEG has secured contractual commitments and options for combustion turbines and related equipment representing approximately 14,000 MW of net generating capacity, including 3,868 MW in greenfield development.

In 2000, PG&E NEG entered into agreements with two master turbine trusts, created to own and facilitate the development, construction financing and leasing of generating facilities that will use 41 turbines to be manufactured by General Electric and Mitsubishi. PG&E Corporation and PG&E NEG committed to provide up to $314 million in equity to meet PG&E NEG's obligations to the trusts. As of May 29, 2001, the trusts had incurred $216 million of expenditures. On May 29, 2001, PG&E NEG used $216 million of its new $280 million revolving credit facility to purchase the turbines from the master turbine trusts. As of December 31, 2001, PG&E NEG has borrowed $221 million against the total borrowing capacity of this facility. The facility is due to be fully repaid on December 31, 2003.

PG&E NEG has entered into, long-term service agreements for the maintenance and repair of its combustion turbine or combine cycle generating plants. These agreements are for periods up to 18 years.

Greenfield Development

PG&E NEG's advanced developed projects are natural gas-fired combined-cycle generation facilities and consist of the following:

Name	Turbine Technology[1]	Number of Turbines	Size (MW)
Mantua Creek	GE 7FB	3	897
Liberty	MHI 501G	3	1,203
Badger	MHI 501G	3	1,170
Umatilla	GE 7FB	2	598
Total		11	3,868

(1) GE 7FB refers to F Technology General Electric 7FB Turbine, and MHI 501G refers to G Technology Mitsubishi 501G Turbine.

These projects were all planned for operation in 2004, with construction starting prior to mid 2002. Recent changes in the power markets have caused PG&E NEG to defer these projects. As a result of a review of the market conditions for new generation, PG&E NEG expects to delay all of its development projects, and swap or sell some of its generation projects under development. In the case of projects that it does retain, PG&E NEG intends to manage its permit and equipment commitments to enable it to delay the start of construction until market conditions warrant, generally between 12 and 36 months from the original plan. Delaying development projects, including Mantua Creek, will result in capital expenditure savings of approximately $1 billion in each of the years 2002 and 2003.

Development has largely been completed for the Mantua Creek project and it is ready to begin construction. PG&E NEG has entered into a construction contract for the facility and released the contractor to perform a limited amount of early construction activities. In light of the current market outlook, PG&E NEG is planning to delay construction of this facility for at least 12 months. As of December 31, 2001, PG&E NEG has recorded assets of $168 million for Mantua Creek, representing equipment payments, construction activities and development costs. PG&E NEG has commenced negotiations with construction contractors and other parties to the project in order to address this delay. If PG&E NEG is not able to reach agreement with these parties and decides to abandon the project, it will be required to write-off approximately $110 million of capitalized and termination costs. This amount does not include major equipment costs. If PG&E NEG is able to reach agreement with these parties, PG&E NEG could defer its near-term capital expenditures, including equipment. In either the deferral or cancellation scenario, PG&E NEG would not incur capital expenditures of approximately $293 million in 2002 and $140 million in 2003.

Equipment Procurement

The following table describes the turbines for which contractual commitments or options exist:

Manufacturer and Type	Quantity of Turbines	Estimated Generating Capacity[1] (MW)
G Technology		
Mitsubishi 501G Turbine	18	7,152
F Technology		
General Electric 7FB Turbine	23	6,877
Total	41	14,029

[1] Approximate base load and peaking/intermediate capacity based on anticipated configuration of the turbine.

The agreement with Mitsubishi includes steam turbines and heat recovery steam generators. For the General Electric turbines, PG&E NEG has entered into separate agreements with Hitachi to supply such equipment. PG&E NEG also has agreements with Hitachi for long lead-time main step-up transformers for both the Mitsubishi and General Electric equipment.

As a result of continuing review of its development program, PG&E NEG may defer, cancel, sell, joint venture, or otherwise dispose of some or all projects in development and the equipment associated with those projects. In connection with its current revised development plans, PG&E NEG has restructured some of the equipment purchase and option commitments to provide additional flexibility in payment terms and delivery schedules to better accommodate the potential delay, swap, or sale of generation projects in development. If further projects are deferred or canceled a mismatch between equipment delivery schedules and development plans may be created. If equipment delivery schedules cannot be adjusted, PG&E NEG may be compelled to choose between paying for equipment which would have to be stored for future use or terminating the commitments to purchase the equipment. If commitments to purchase the equipment are terminated, PG&E NEG would incur termination costs to the equipment vendors consisting of amounts shown as assets on the Consolidated Balance Sheets plus all additional cash payments, if any, due upon termination. Exposure for these equipment termination costs gradually increases over time. Cash exposure for termination costs is offset by amounts expended for the equipment through the date of termination.

Generally, each equipment supply contract allows cancellation of any or all of the commitments to purchase the equipment for a predefined cost. To date, equipment commitments or options have not been cancelled. PG&E NEG continues to work with its vendors to defer payments, delay increases of termination fees, and revise equipment delivery dates. PG&E NEG has good relationships with its vendors and has to date, been largely successful in these efforts. However, there is no assurance that PG&E NEG will be able to continue to modify these agreements to minimize the termination costs and match equipment deliveries with its evolving development plans. The estimates of PG&E NEG's exposure for termination costs are, in part, based upon current contractual arrangements and amendments thereto, which PG&E NEG is confident will be implemented.

Without any further delays or agreements with the equipment vendors, PG&E NEG's committed costs for equipment related to its entire development program, except Mantua Creek (discussed below) are approximately $18 million in 2002, and $160 million in 2003. Aggregate equipment termination costs for the entire development program other than Mantua Creek were $247 million as of December 31, 2001, and are estimated to increase to $254 million at December 31, 2002, and $368 million at December 31, 2003. PG&E NEG has recorded $221 million (excluding Mantua Creek) of prepayments for equipment as of December 31, 2001.

PG&E NEG is currently marketing its development projects for potential sale. If a buyer is found which is willing to purchase equipment which may be used with a purchased project, and PG&E NEG is able to comply with the conditions in its equipment contracts, termination costs can be avoided. However, there can be no assurance that PG&E NEG will be successful in selling any or all of these projects or that the buyers will be able or willing to undertake the equipment purchase obligations.

The amounts set forth in the Commitments and Capital Expenditures Table above are based upon the current contractual provisions assuming all development projects under construction on the schedule set forth in such contracts. These schedules remain subject to change and the commitments may be deferred or cancelled by contract terms.

Turbine Technology

Many of the turbine purchases and commitments use the latest generation of combustion technology, which is commonly known as G technology. These G technology turbines are designed to result in higher capacity utilization, lower cost output and a 2 percent to 4 percent higher combustion efficiency than the F technology turbines generally being deployed in most new generating facilities in North America. PG&E NEG has also secured rights to 23 7FB turbines from General Electric. These turbines are expected to be slightly less efficient than G technology turbines, but are designed to have 1 percent or 2 percent higher combustion efficiency than the more standard F technology turbines. In light of its deployment of advanced technology, PG&E NEG has also arranged with each of its turbine vendors for long-term service agreements. These agreements have predetermined pricing, and cover the schedule for major overhauls, parts and associated labor, for at least ten years.

Two of the suppliers of G technology turbines have encountered problems in their initial commercial installations of these turbines. The Lake Road and La Paloma facilities are being constructed by Alstom Power, Inc. (Alstom). Alstom has advised that it may take up to three years to develop and implement modifications to its G technology turbines that are necessary to achieve the guaranteed level of efficiency and output. It is expected that the Lake Road and La Paloma facilities will begin commercial operations at reduced performance and output levels because of the technology issues with Alstom's G technology turbines. Start-up problems were also encountered with the Siemens Westinghouse G technology installed in the Millennium facility. These problems delayed the original date of commercial operations for this facility, which began commercial operations in April 2001. Commercial operations commenced, pursuant to a settlement among Millennium, Bechtel and Siemens which, among other things, deferred fuel oil commissioning and testing. The facility has not yet demonstrated satisfactory performance using fuel oil and availability has been hampered by continuing new technology issues. It is not expected that the start-up and initial operations problems with the Siemens Westinghouse G technology turbine installed at the Millennium facility will result in a long-term, reduction of performance below guaranteed levels of efficiency or output. The construction contracts for each of the Millennium, Lake Road and La Paloma projects provide for liquidated damages that significantly, but not fully, offset the financial impact associated with the delays of these turbines in achieving their expected level of performance.

Construction Issues

Alstom has fallen significantly behind its construction schedule on the Lake Road and La Paloma facilities and is paying liquidated damages for such delay. Alstom is implementing a recovery plan with a target commercial operations date in the first half of 2002 for Lake Road and the end of 2002 for La Paloma. In addition, it is expected that the Lake Road facility will not be able to operate on fuel oil until after commercial operations commence. The ability to operate on fuel oil is contemplated in Lake Road's permit from the State of Connecticut. La Paloma is designed to use only natural gas.

PG&E NEG Equity Commitment and Rating Triggers

PG&E NEG has provisions in some of its financial arrangements that require it or a specified affiliate to maintain certain ratings from S&P and/or Moody's. These provisions are referred to as "rating triggers." The specifics of the ratings that are required to be maintained, the remedy and cure periods should an event of downgrade occur, and the results if PG&E NEG does not take certain actions as a result, differ with each agreement. These provisions generally require PG&E NEG to provide cash to meet outstanding obligations or post cash or a letter of credit as collateral in the event that PG&E NEG could not provide other acceptable replacement security.

PG&E NEG's most significant rating triggers related to its loans include the following:

- PG&E NEG's guarantee backing the $280 million equipment facility requires that PG&E NEG maintain a BBB- or Baa3 rating from either S&P or Moody's, respectively. In the event of a downgrade, PG&E NEG has 30 days to post an acceptable replacement security, or, following receipt of a payment demand from the lenders, PG&E NEG has 5 days to repay all outstanding borrowings under the facility.
- The $609 million equity commitments for Lake Road and La Paloma require that PG&E NEG maintain BBB- or Baa3 ratings from either S&P or Moody's. These rating triggers provide for a 30 day period to post replacement security after which lenders could request equity funding within five days.

- The PG&E NEG guarantee backing the $701 million equity commitment related to the $1.075 billion portfolio financing requires PG&E NEG to maintain a BBB- or Baa3 rating from S&P or Moody's, respectively. In the event of a downgrade, PG&E NEG has 30 days to fund the balance of the outstanding equity commitment.

There are also rating triggers in certain energy trading related guarantees and guarantees to third parties. These are discussed below under Guarantees Supporting Trading Related Agreements.

Plains End – Financing and Equity Commitment

In September 2001, PG&E NEG closed on a $69.4 million non-recourse secured five-year project financing for the construction of the Plains End generating project in Colorado. At December 31, 2001, there was $23.3 million outstanding under the facility. At December 31, 2001, PG&E NEG had invested $16.2 million in the Plains End property, and had a payment guarantee to the construction contract of $5 million.

The emissions guarantee for particulate matter provided by the construction contractor on the Plains End facility does not use the same test method as required by the facility's air permit. PG&E NEG is currently seeking to modify its air permit emissions rates to address this issue. Pending the receipt of such modification, and demonstration or guarantee from the construction contractor that the facility can comply with the particulate matter emissions rates as modified. PG&E NEG's lenders have withheld funding for construction of the facility. The construction contractor has agreed to continue work and defer pay until March 15, 2002, which is the date that PG&E NEG expects the requested air permit modification will be issued.

Tolling Agreements

PG&E NEG has entered into a number of long-term tolling agreements. Under tolling agreements, PG&E NEG, at its discretion, supplies fuel to a power plant owned by a third party, then sells the output in the competitive market. The power plant owner receives a fee for converting the fuel into electricity. As of December 31, 2001, its annual estimated committed payments under these contracts ranged from $33 million to $211 million, resulting in total committed payments over the next 27 years of approximately $4 billion. PG&E NEG provides payment guarantees under each of these agreements and receives performance availability guarantees from its counterparties. As of December 31, 2001, PG&E NEG has extended about $600 million of such guarantees with an initial face value varying from $20 million to $250 million declining over time as the future obligation declines. Each of these guarantees contains a trigger event provision that requires PG&E NEG to replace the guarantee or provide alternative collateral in the event that its credit rating drops to below investment grade as measured by S&P or Moody's. Although the face value of these guarantees is significant, the exposure in the event of a default is generally limited to payment of the difference between the value of the current tolling agreement and the value of a substitute tolling agreement that the counterparty could enter into at market terms. As of December 31, 2001, the net exposure under the guarantee supporting tolling agreements was 3.2 percent or $20 million. PG&E NEG intends to work with tolling counterparties to amend existing agreements to replace the ratings triggers with various covenant packages. Any success in these efforts will depend on the unanimous cooperation of multiple parties.

Facility – Leases

The construction costs of both the Lake Road and the La Paloma facilities are being financed under separate lease facilities with substantially similar terms. Under these arrangements, a third-party owner/lessor is financing construction of each facility while PG&E NEG is serving as construction agent. Once each facility is completed, the leases for the projects will begin and will continue up to five years from financial closing. The obligations under these leases will commence at the completion of construction and are estimated to begin in 2002. At the end of each lease, PG&E NEG has the option to extend the lease at fair market value, purchase the project, or act as remarketing agent for the lessor for a sale of the project to a third party. If PG&E NEG acts as remarketing agent for the lessor, then PG&E NEG is obligated to the lessor for up to 85 percent of the project's costs, if the proceeds from the sale are less than the lessor's book value. PG&E NEG has committed to the project lenders to contribute equity of up to $230 million for Lake Road and up to $379 million for La Paloma through the purchase of the portion of project loans secured by guarantees on March 31, 2003. The equity infusions could be triggered earlier by a downgrade of PG&E NEG to below investment grade from both S&P and Moody's or the failure to meet certain debt covenants of either projects.

As of December 31, 2001, project costs subject to these agreements totaled $1,012 million, and total costs for both projects are expected to be approximately $1,149 million. The projects are included in the Consolidated

Financial Statements. Assuming project completion, expected future annual lease payments for these two projects are estimated to range from $18 million to $59 million.

Off-Balance Sheet – Non-Recourse Debt

Non-recourse debt at subsidiaries in which PG&E NEG has ownership interests but does not have management control is not consolidated and is not recorded on the balance sheet of PG&E NEG since these entities are accounted for under the equity method of accounting and PG&E NEG has no liability for the repayment of that debt. The total amount of non-recourse debt borrowed by unconsolidated investment entities was approximately $1.1 billion. PG&E NEG has no contingent liabilities or funding obligations to cover these loans, which are secured by the assets of the project entities that incurred the debts and are serviced from the cash flows of these entities.

Fuel Supply and Transportation Agreements

PG&E NEG, through its subsidiaries PG&E GenLLC and PG&E ET, has entered into various gas supply and firm transportation agreements with various pipelines and transporters to provide fuel transportation services to PG&E NEG's own power plants and other customers. Under these agreements, PG&E NEG must make specified minimum payments each month.

Power Purchase Agreements

PG&E NEG, through its subsidiaries, assumed rights and duties under several power purchase contracts with third-party independent power producers as part of the acquisition of the New England Electric System (NEES) assets. At December 31, 2001, these agreements provided for an aggregate of 800 MW of capacity. Under the transfer agreement, PG&E NEG is required to pay to NEES amounts due to the third-party power producers under the power purchase contracts.

Operating Leases

PG&E NEG and its subsidiaries have entered into several operating lease agreements for generating facilities and office space. Lease terms vary between 3 and 48 years. In November 1999, a subsidiary of PG&E NEG entered into a $479 million sale-leaseback transaction whereby the subsidiary sold and leased back a pumped storage station under an operating lease. Operating lease expense amounted to $54 million, $70 million, and $70 million in 2001, 2000, and 1999, respectively.

Other Commitments

PG&E NEG has entered into long-term service agreements for the maintenance and repair of certain of its combustion turbine or combined-cycle generating plants. These agreements are for periods up to 18 years. In addition, PG&E NEG has entered into agreements with certain local governments that provide for payments in lieu of property taxes for certain of its generating facilities.

Guarantees Supporting Trading Related Agreements

PG&E NEG's energy marketing, trading, hedging, and risk management operations are conducted with counterparties under various master agreements. These agreements typically provide for reciprocal extension of credit lines based on credit worthiness standards. Net open positions under these agreements are marked-to-market on a routine basis and if the net exposed position including receivables and payables falls outside of the established credit limits, then additional collateral must be provided. Therefore, key components of a successful energy business consist of credit worthiness, liquidity resources, risk management systems that provide current mark-to-market of all open positions, and a strong credit department to evaluate and manage counterparty credit risk.

In addition to guarantee supporting tolling agreements, as of December 31, 2001, PG&E NEG and its subsidiaries provided $2.3 billion of guarantees to counterparties in support of its energy trading operations. This includes provision of fuel and pipeline capacity to, and sale of energy products from its power plants. These guarantees were provided in favor of approximately 200 counterparties to permit and facilitate physical and financial transactions in gas, pipeline capacity, power, coal, and related commodities and services with these entities. Typically, the overall exposure under these guarantees is only a fraction of the face value of the guarantees, since not all counterparty credit limits are fully utilized at any time and there may be no outstanding transactions or financial exposure underlying an outstanding guarantee. PG&E NEG receives similar deposits, letters of credit, and guarantees as collateral for credit extended by PG&E NEG to these, in many cases, same counterparties. These offsetting exposures can often be netted in lieu of posting alternative collateral. As of December 31, 2001, PG&E NEG's net exposure under its guarantees was approximately 8 percent or about $190 million. This exposure is a contingent obligation that could be called only if PG&E NEG or one of its subsidiaries fails to meet and cure a payment obligation.

The continued acceptability of many of these guarantees is dependent on PG&E NEG's maintaining various standards of creditworthiness. As a result, maintenance of investment grade ratings by one or more rating agencies is an important criterion for PG&E NEG and its subsidiaries. If PG&E NEG or its subsidiaries are downgraded by one or more of the rating agencies, PG&E NEG may be required to provide alternative collateral to replace guarantees that no longer meet the creditworthiness standards of the agreements. Therefore, PG&E NEG and its trading subsidiaries maintain substantial cash balances and credit capacity to provide liquidity to its businesses in the event that open credit limits are exceeded through volatility, or in the event of a credit downgrade.

The amount of exposure under master agreements subject to securitization requirements in the event of a credit downgrade of PG&E NEG or its subsidiaries to below investment grade by one or more rating agencies was approximately 5 percent of the outstanding guarantees or $105 million at December 31, 2001. PG&E NEG manages this risk through maintenance of investment grade credit ratings at several principal operating subsidiaries so that guarantees of one entity could be substituted for another in the event of a credit downgrade of one entity.

Guarantees Supporting Other Agreements with Third Parties

PG&E NEG and its subsidiaries have issued in excess of $800 million of guarantees in support of various performance and payment obligations under agreements with third parties. Of these guarantees supporting other agreements with third parties, $485 million have investment grade ratings maintenance requirements. In addition, a number of other agreements have specific security provisions requiring maintenance of investment grade ratings. In the event of a downgrade below the trigger level and exhaustion of any cure period, some of these agreements would allow the counterparty to demand payment for any outstanding obligations or contract termination penalties, if any. Others simply provide the counterparty with a right to terminate the contract.

PG&E GTN Pipeline Expansion

PG&E GTN is in the process of completing its 2002 Expansion Project, which when completed will expand its system by approximately 217 million cubic feet (Mcf) per day. Approximately 40 Mcf per day of that expansion capacity was placed in service in November 2001; the remaining capacity is scheduled to be placed in service by the end of 2002. The total cost of the expansion is estimated to be $122 million. PG&E GTN has filed an application with the FERC for approval to complete a second expansion of approximately 150 Mcf per day of additional capacity, at a cost of approximately $111 million. PG&E GTN expects to fund these expansions from cash provided by operations and, to the extent necessary, external financing and capital contributions from PG&E NEG. PG&E GTN has also initiated a preliminary assessment of a Washington lateral pipeline that would originate at the PG&E GTN mainline system near Spokane, Washington, and extend west approximately 260 miles into the Seattle/Tacoma metropolitan area.

North Baja Pipeline

PG&E NEG has entered into a joint development agreement for the development of a new 500 million cubic feet per day gas pipeline, North Baja, to deliver natural gas to Northern Mexico and Southern California. The North Baja project is expected to be completed by the end of 2002. PG&E NEG owns all of the United States section of this cross-border project. PG&E NEG's share of the costs to develop this project will be approximately $146 million. PG&E NEG expects to fund this project from the issuance of non-recourse debt, and available cash or draws on available lines of credit.

PG&E Corporation Guarantees

As of December 31, 2001, PG&E NEG had replaced or eliminated all of the previously issued PG&E Corporation guarantees, except for an office lease guarantee of $16 million relating to the PG&E NEG's San Francisco office, with a combination of guarantees provided by PG&E NEG or its subsidiaries and letters of credit obtained independently by PG&E NEG. In addition, PG&E NEG has negotiated substitute equity commitments with certain third parties for construction financing agreements, replacing all PG&E Corporation equity commitments included in those agreements. In addition, PG&E NEG has also negotiated substitute equity commitments with certain third parties for construction financing agreements, replacing all PG&E Corporation equity commitments included in those agreements.

PG&E Corporation also has a $2 million guarantee supporting the Utility's investment in low-income housing projects.

RESULTS OF OPERATIONS

The table below shows for 2001, 2000, and 1999 certain items from our Consolidated Statements of Operations and Consolidated Statements of Cash Flows detailed by Utility and PG&E NEG operations of PG&E Corporation. (In the "Total" column, the table shows the combined results of operations for these groups.) The information for PG&E Corporation (the "Total" column) includes the appropriate intercompany eliminations. Following this table, we discuss our results of operations.

		PG&E National Energy Group					
(in millions)	Utility	Total PG&E NEG	Integrated Energy & Marketing	Interstate Pipeline Operations	PG&E NEG Eliminations	PG&E Corporation & Other Eliminations[1]	Total
2001							
Operating revenues	$10,462	$12,669	$12,429	$ 246	$ (6)	$(172)	$22,959
Operating expenses	7,984	12,391	12,283	109	(1)	(152)	20,223
Operating income							2,736
Interest income							213
Interest expense							(1,213)
Other income (expense), net							(38)
Income taxes							608
Income from continuing operations							1,090
Net income							1,099
Net cash provided by operating activities							5,274
Net cash used by investing activities							(2,900)
Net cash provided by financing activities							591
EBITDA[2]	3,333	459	261	182	16	(17)	3,775
2000[3]							
Operating revenues	9,637	16,779	15,661	1,112	6	(196)	26,220
Operating expenses	14,838	16,388	15,467	906	15	(199)	31,027
Operating loss							(4,807)
Interest income							266
Interest expense							(788)
Other income (expense), net							(23)
Income tax benefit							(2,028)
Loss from continuing operations							(3,324)
Net loss							(3,364)
Net cash provided by operating activities							671
Net cash used by investing activities							(970)
Net cash provided by financing activities							2,364
EBITDA[2]	(1,244)	500	289	249	(38)	47	(697)
1999[3]							
Operating revenues	9,228	11,812	10,423	1,372	17	(221)	20,819
Operating expenses	7,235	12,963	10,410	2,550	3	(257)	19,941
Operating income							878
Interest income							118
Interest expense							(772)
Other income (expense), net							37
Income taxes							248
Income from continuing operations							13
Net loss							(73)
Net cash provided by operating activities							2,287
Net cash used by investing activities							(117)
Net cash used by financing activities							(2,043)
EBITDA[2]	$ 3,523	$ (945)	$ 121	$ (997)	$(69)	$ 117	$ 2,695

(1) All inter-segment transactions are eliminated.

(2) EBITDA is defined as income before provision for income taxes, interest expense, interest income, deferred electric procurement costs, depreciation and amortization and provision for loss on generation-related assets and under-collected purchased power costs. EBITDA is not intended to represent cash flows from operations and should not be considered as an alternative to net income as an indicator of PG&E Corporation's operating performance or to cash flows as a measure of liquidity. Refer to the Statement of Cash Flows for the U.S. GAAP basis cash flows. PG&E Corporation believes that EBITDA is a standard measure commonly reported and widely used by analysts, investors, and other interested parties. However, EBITDA as presented herein may not be comparable to similarly titled measures reported by other companies.

(3) Segment information for the prior periods has been restated to conform with new segment presentation. (See Note 17 of the Notes to the Consolidated Financial Statements.)

PG&E Corporation – Consolidated

Overall Results

PG&E Corporation's results of operations continue to be impacted by the California energy crisis and the Utility's bankruptcy filing. Please see the "Liquidity and Capital Resources" section above, and Notes 2 and 3 of the Notes to the Consolidated Financial Statements for more information.

PG&E Corporation's net income for the year ended December 31, 2001, was $1,099 million, compared to a net loss of $3,364 million for the same period in 2000, representing an increase of $4,463 million. Substantially all of this change was attributable to the Utility.

PG&E Corporation and the Utility expect future earnings to continue to reflect increased volatility as a result of no longer being able to reflect the impact of generation-related regulatory balancing accounts in their financial statements. Financial reporting standards require that these amounts be accounted for as expenses unless they can be deemed probable of recovery. Due to the uncertainty created by the California energy crisis, the Utility cannot meet the accounting probability standard required to defer generation costs for future recovery. As such, costs and revenues historically deferred in regulatory balancing accounts now directly impact net income. The Utility's net income will be impacted by changes in electricity and gas costs, customer demand, weather, costs of operations, conservation, regulatory orders, and other items.

The changes in performance for the years ended December 31, 2001, and 2000, are generally attributable to the following factors:

- The Utility's generation-related component of its electric revenues was greater than its generation-related costs by $458 million for the year ended December 31, 2001, and was caused primarily by the following three factors. First, the Utility recognized an offset against previously expensed purchased power costs of $327 million related to the market value of terminated bilateral contracts. Second, beginning in June 2001, the Utility began collecting revenues associated with the CPUC's March 27, 2001, interim energy procurement surcharges. Third, in the second quarter and continuing throughout the balance of the year, the wholesale energy market stabilized and the DWR began providing for the entire net open position.
- As a result of the liquidity crisis attributable to the California energy crisis, PG&E Corporation has had a significant increase in unpaid debts and has increased its borrowings significantly, all accruing interest. Additionally, the effective interest rate due on these new borrowings has increased because of the higher risk associated with PG&E Corporation's financial position. The incremental cost of these borrowings was $262 million, after tax, for the year ended December 31, 2001, of which $218 million relates to the Utility and $44 million was incurred by PG&E Corporation.
- The Utility has incurred incremental financial and legal expenses associated with the bankruptcy proceedings and the development of a plan of reorganization. For the year ended December 31, 2001, total incremental expenses were approximately $78 million, after tax, consisting of $42 million of costs relating to the Utility and $36 million of costs pertaining to PG&E Corporation.
- During 2001, the Utility recognized losses of approximately $66 million, after tax, associated with the involuntary termination of gas transportation hedges caused by a decline in the Utility's credit rating.
- During the third quarter of 2001, the CPUC issued two decisions modifying its previous decision in the Utility's 1999 General Rate Case (GRC). The first, to correct a tax computational error in the CPUC's decision, had the impact of adding approximately $34 million to net income (approximately $25 million related to 1999 and 2000), and the second modification had the impact of decreasing net income by approximately $70 million of which $51 million related to 1999 and 2000.
- PG&E NEG increased earnings by $31 million for the year ended December 31, 2001, as compared to 2000. This increase was the result of higher gross margins at the wholesale energy business, the gain on a sale of a development project, and a lower effective federal tax rate resulting from synthetic fuel credits. In addition, the 2000 results include a $40 million loss on discontinued operations.
- PG&E NEG took a charge against income in the fourth quarter of 2001 for the net exposure of $35 million relating to trading contracts with Enron. For a detailed discussion of this write-off, please see Note 4 of the Notes to the Consolidated Financial Statements.

- For various transactions that were recorded in 2000, such as the Utility's write-off of its remaining generation-related regulatory assets and under-collected purchased power costs, and the Utility's provision for potential losses associated with litigation, there were no similar transactions in 2001. As such, performance in 2001, when compared to the prior year, is impacted by those transactions that occurred in 2000. The 2000 transactions are discussed further below.
- The effective tax rate for PG&E Corporation decreased to 35.8 percent in 2001, as compared to 37.9 percent in 2000, principally as a result of synthetic-fuel credits earned during the year.

Net loss for the year ended December 31, 2000, increased to $3,364 million from a net loss of $73 million for the same period in 1999. Of the $3,291 million increase, the Utility's net loss allocated to common stock for the year ended December 31, 2000, accounted for $4,271 million of the increase, partially offset by an increase in PG&E NEG net income of $1,048 million.

The decrease in performance of 2000 compared to 1999 results of operations is attributable to the following factors:

- The Utility's earnings were impacted as a result of the write-off of its remaining generation-related regulatory assets and under-collected purchased power costs ($4.1 billion, after tax). Because of the substantial uncertainty created by the California energy crisis, the Utility could no longer conclude that energy and transition costs, which had been deferred on its Consolidated Balance Sheets, were probable of recovery. Under Statement of Financial Accounting Standard (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," if a rate mechanism provided by legislation or other regulatory authority were subsequently established that made recovery from regulated rates probable as to all or a portion of the under-collection that was previously charged against earnings, a regulatory asset would be reinstated with a corresponding increase in earnings.
- As a result of the high cost of power, with no offsetting revenues, the Utility and PG&E Corporation had a net loss for California tax purposes. California law does not permit carrybacks of such losses and only permits carryforwards of 55 percent of such losses. As a result, PG&E Corporation was unable to recognize $79 million of state tax benefits because of California law. Income tax expense was also higher due to tax depreciation adjustments and a reduction in investment tax credits.
- In 2000, the Utility recorded a provision ($83 million, after tax) for potential losses associated with litigation discussed in Note 16 of the Notes to the Consolidated Financial Statements.
- At the end of 1999, PG&E Corporation announced its plans to dispose of PG&E GTT and these assets were written down to estimated fair value, resulting in a charge of $890 million ($2.24 per share). PG&E GTT operated at a breakeven basis in 2000, while it reported a net loss from operations of $7 million ($0.02 per share) in 1999. These operations were sold on December 22, 2000.
- Also at the end of 1999, PG&E Corporation announced its plans to dispose of PG&E ES and these assets were written down to net realizable value. PG&E ES operated at a loss during 2000. However, those losses were charged against reserves established in 1999 and did not impact the current results from operations, while PG&E ES reported losses of $98 million ($0.27 per share) for 1999. Additionally, during the latter half of 2000, PG&E Corporation recorded after-tax charges of $40 million ($0.11 per share) to reflect the closing of transactions to dispose of the retail energy services business and related commodity portfolio.
- PG&E ET's net income in 2000, net of restructuring charges of $13 million, after tax ($0.04 per share), related to the move of natural gas trading operations from Houston, Texas, to Bethesda, Maryland, increased $57 million compared to 1999 results due to across-the-board improvements in natural gas and power trading, asset management, and structured transactions. While trading in electric commodities has generally been profitable, the results of the gas trading operations have improved significantly as a result of structured transactions. Additionally, the gas trading operations benefited from the highest gas prices in a number of years. The power trading operations have benefited from volatile prices throughout the United States.
- PG&E Gen and PG&E GTN earnings decreased slightly from 1999 levels, primarily attributable to a decline in operating results in the generating business and a decrease in operating income at PG&E GTN primarily as a result of settlements received in the amount of $19 million for negotiations regarding transportation contracts and other related issues, resulting in the restructuring and/or termination of these transportation contracts in 1999 with no similar transactions in 2000.

- The effective tax rate for PG&E Corporation decreased to 37.9 percent in 2000 compared to 95 percent in the prior year as a result of a higher effective tax rate in 1999, largely due to the disposition of PG&E GTT which resulted in a capital loss for tax purposes, which could not be fully recognized.

Dividends

PG&E Corporation's historical quarterly common stock dividend was $0.30 per common share, which corresponded to an annualized dividend of $1.20 per common share.

On January 10, 2001, the Board of Directors of PG&E Corporation suspended the payment of its fourth quarter 2000 common stock dividend of $0.30 per share declared by the Board of Directors on October 18, 2000, and payable on January 15, 2001, to shareholders of record as of December 15, 2000. These defaulted dividends were later paid on March 2, 2001, in conjunction with the refinancing of PG&E Corporation obligations, discussed above under the Liquidity and Capital Resources section. No dividends were declared in 2001. PG&E Corporation's refinancing agreement prohibits dividends from being declared or paid until the term loans have been repaid.

Utility

Overall Results

The Utility's income available for common stock was $990 million for 2001, compared to a loss of $3,508 million in 2000. The Utility had higher earnings primarily due to three factors: (1) increased electric revenues, (2) decreased electricity purchase costs, and (3) decreased depreciation, amortization, and decommissioning expenses resulting from the write-off of remaining generation-related regulatory assets and under-collected purchased power costs in 2000.

The Utility's loss allocated to common stock was $3,508 million in 2000 compared to 1999 income of $763 million. The decrease was primarily the result of the write-off of its remaining generation-related regulatory assets and under-collected purchased power costs, a provision for potential litigation losses, and higher income tax expense.

Electric Operations

Electric Revenues

The following table shows the components of the Utility's electric revenue by customer class:

	Year ended December 31,		
(in millions)	2001	2000	1999
Residential	$ 3,396	$ 3,062	$2,975
Commercial	4,105	3,110	2,980
Industrial	1,554	1,053	1,044
Agricultural	525	420	404
Total electric revenue	9,580	7,645	7,403
Direct access credits	(461)	(1,055)	(348)
DWR pass-through revenues	(2,173)	—	—
Miscellaneous	380	264	177
Total electric operating revenues	$ 7,326	$ 6,854	$7,232

Electric revenues in 2001 increased by $472 million, or 6.89 percent, from 2000 and were significantly affected by three factors:

First, there were $594 million fewer direct access credits. In accordance with CPUC regulations, the Utility provides an energy credit to those customers (known as direct access customers) who have chosen to buy their electric generation energy from an energy service provider (ESP) other than the Utility. The Utility bills direct access customers based upon fully bundled rates (generation, distribution, transmission, public purpose programs, and a competition transition charge). However, the direct access customer receives an energy credit equal to the average generation price multiplied by customer energy usage for the period.

At December 31, 2001, the estimated total of accumulated unpaid credits for direct access customers was approximately $506 million, of which $469 million has been classified as subject to compromise on the Utility's Consolidated Balance Sheets. The actual amount that will be refunded to ESPs or directly to the customer will be dependent upon the outcome of the Utility's bankruptcy proceeding, when the rate freeze ends, and whether there are any adjustments made to wholesale energy prices by the FERC.

Second, generation-related surcharges increased revenues but were offset by pass-through revenues collected on behalf of the DWR. Energy procurement surcharges authorized by the CPUC increased revenues by $2,225 million. The increase provided by the surcharges was offset by the pass-through revenues of $2,173 million for electricity that the DWR provided to the Utility's customers. Revenues collected on behalf of the DWR and the related costs are not reflected in the Utility's Consolidated Statements of Operations as the Utility is a collection agent for the DWR. See "California Department of Water Resources" under Note 3 of the Notes to the Consolidated Financial Statements.

Third, conservation efforts by the Utility's customers in response to the California energy crisis, mild weather, and higher prices from the energy surcharge implemented in June 2001 reduced electric sales volumes by 3 percent in 2001 compared to 2000.

Electric revenue in 2000 decreased by $378 million, or 5.23 percent, from 1999 mainly due to industrial and commercial customers receiving direct access credits in 2000. The Utility's electric sales volumes were 3 percent higher in 2000 than 1999, which helped to reduce the effect of the direct access credits on revenues.

Cost of Electric Energy

The following table shows the components of the Utility's cost of electric energy:

(in millions)	Year ended December 31, 2001	2000	1999
Cost of electric energy[1]	$ 2,774	$ 6,741	$ 2,411
Deferred electric procurement cost	—	(6,465)	—
Provision for loss on generation - related regulatory assets and under-collected purchased power costs	—	6,939	—
Total cost of electricity expenses	$ 2,774	$ 7,215	$ 2,411
Average cost of electricity per kWh	$ 0.059	$ 0.093	$ 0.034
Total energy purchased and generated (MWh)	46,922	72,261	70,228

(1) Represents the combined cost of the Utility's owned-generation and energy purchase costs.

The decrease in the total cost of electricity expenses in 2001 of $4,441 million is primarily the result of two factors. First, the Utility was no longer purchasing electricity through the PX market. Instead, the DWR purchased 28,640 megawatt-hours (MWh) of electricity on behalf of the Utility's customers to cover the Utility's net open position in 2001. The cost of the DWR's purchases is not reflected in the Utility's financial statements because the Utility is a collection agent on behalf of the DWR. Second, a statewide energy conservation campaign and mild weather caused the Utility's customers to use approximately 3 percent less energy compared to 2000.

The increase in the total cost of electricity expenses of $4,804 million from 2000 compared to 1999 is primarily attributable to the write-off of the Utility's transition cost regulatory assets and under-collected purchased power costs. In addition, electricity purchase costs increased significantly during the latter half of 2000. The average cost per kWh of electricity was $0.093 per kWh for 2000, whereas revenues for the generation component of frozen rates were approximately $0.054 per kWh. The amount of purchased power costs in excess of the revenue for the generation component of frozen rates was reflected as deferred electric procurement costs prior to the year-end write-off.

Gas Operations

Gas Revenues

In 2001, gas revenues increased $353 million due to a higher average price of gas, which was passed on to customers and collected in gas revenues. The increase was offset by an approximate 4 percent decrease in usage in 2001 primarily as a result of conservation efforts. The average bundled price of gas sold in 2001 was $10.55 per Mcf compared to $8.40 per Mcf in 2000.

The increase in gas revenues for 2000, compared to 1999 related primarily to higher gas prices. The average bundled price of gas sold per Mcf was $8.40 in 2000 and $5.69 per Mcf in 1999. Gas sales volumes for bundled sales and transportation decreased by 9 percent from 1999 sales volumes due to warmer winter weather, while gas sales volumes for transportation-only service increased by 25 percent due to increased demands by electric generators to meet air-conditioning loads due to warmer summer weather and new transportation contracts.

Cost of Gas

In 2001, the Utility's cost of gas increased by $407 million principally due the increase in the unit cost of gas to $6.77 per Mcf in 2001 from $5.07 per Mcf in 2000. In addition, the cost of gas increased due to the recognition of losses of $111 million on terminated contracts.

In 2000, the Utility's cost of gas increased compared to 1999 due to increases in the unit cost of gas during the latter half of 2000. The average unit cost of gas that the Utility paid was $5.07 per Mcf in 2000 and $2.39 per Mcf in 1999.

Other Operating Expenses

Operating and Maintenance

In 2001, the Utility's operating and maintenance expenses decreased by $302 million primarily due to reduced expenses related to the liability for legal matters of $140 million, and lower regulatory and other generation-related costs. In 2000, the Utility's operating and maintenance expenses increased by $165 million primarily due to an increase in the liability for legal matters reserve of $140 million.

Depreciation, Amortization, and Decommissioning

Depreciation, amortization, and decommissioning decreased $2,615 million in 2001 from 2000 due to the accelerated depreciation of generation-related assets in 2000, and as a result of less depreciation being recorded in 2001 as the majority of the generation-related assets were fully depreciated after the acceleration.

Depreciation, amortization, and decommissioning increased $1,947 million in 2000 from 1999. The increase resulted primarily from an increase in recovery of transition costs resulting from higher revenues from sales to the PX of Utility-owned generation, including Diablo Canyon generation, and generation from QFs and other providers. As mandated by the CPUC, these revenues, in excess of the related costs, must be used to recover transition costs.

Interest Expense

In 2001, the Utility's interest expense increased by $355 million compared to 2000 due to increased debt levels and higher interest rates as a result of the Utility's credit rating downgrade.

In 2000, the Utility's interest expense increased to $619 million from $593 million in response to the additional borrowings of the Utility to pay for the escalated electricity purchase costs in the latter half of 2000.

Reorganization Fees and Expenses

In accordance with SOP 90-7, the Utility has reported reorganization fees and expenses separately on the Consolidated Statements of Operations. Such costs primarily include professional fees for services in connection with the Chapter 11 proceedings totaling $97 million. In addition, the Utility has incurred other costs related to the California energy crisis of $23 million which have been included in operating and maintenance expenses.

Dividends

On January 10, 2001, the Utility suspended the payment of its fourth quarter 2000 common stock dividend of $110 million, declared in October 2000, to PG&E Corporation and its wholly owned subsidiary PG&E Holdings, LLC. Until its financial condition is restored, the Utility is precluded from paying dividends to PG&E Corporation and PG&E Holdings, LLC. Dividends on preferred stock are cumulative. Until cumulative dividends on preferred stock are paid, the Utility may not pay any dividends on its common stock.

Dividends paid to PG&E Corporation increased from $440 million in 1999 to $475 million in 2000, in order to maintain the CPUC-mandated capital structure. Dividends paid to preferred shareholders remained at the same level of $25 million in 2000 and 1999.

PG&E NEG

Operating Income

PG&E NEG's operating income declined $113 million in 2001, primarily due to the sale of PG&E GTT in December 2000 which provided operating income of $77 million in 2000. In addition, PG&E NEG incurred a one-time charge in the fourth quarter of 2001 of $60 million related to the termination of certain contracts resulting from the Enron Bankruptcy (principally related to PG&E NEG's energy trading business). These declines were partially offset by the sale of a development project in the third quarter of 2001, which provided operating income of $23 million and general improvement in operating margins in the Integrated Energy and Marketing segment primarily at the New England region generating facilities.

PG&E NEG's operating income increased $1.5 billion in 2000, as compared to 1999, partially due to a $1.3 billion loss recognized in 1999 as the pre-tax impairment charge to reflect PG&E GTT's assets at their fair value.

Operating Revenues

PG&E NEG's operating revenues were $12.7 billion in 2001, a decrease of $4.1 billion or 24 percent from 2000. This decline in operating revenues occurred principally within PG&E NEG's Integrated Energy and Marketing segment, and is mainly due to lower trade volumes and lower realized prices achieved primarily in the third and fourth quarters of 2001. These declines generally were due to higher commodity prices in the wake of the California energy crisis in the second half of 2000 and the decline in economic activity in the U.S. in the second half of 2001. In PG&E NEG's Pipeline segment, the decline in operating revenues of $866 million is primarily due to the sale of PG&E GTT in December 2000.

PG&E NEG's operating revenues were $16.8 billion in 2000, an increase of $5 billion, or 42 percent from 1999. This increase occurred principally within PG&E NEG's Integrated Energy and Marketing segment and was primarily the result of the increased volume of electricity and related products and significantly higher prices for both electricity and natural gas. In addition, two New England region generating facilities were not in service for a portion of the summer of 1999. There were no comparable unplanned outages in 2000. Operating revenues for PG&E NEG's Pipeline segment were $1.1 billion in 2000, a decrease of $260 million or 19 percent from 1999. PG&E GTT's revenues decreased $275 million from 1999, as a result of the decrease in natural gas sales resulting from the transfer of certain gas marketing activities conducted by PG&E GTT to the Integrated Energy and Marketing segment in the middle of 1999, and also resulting from 11 months of revenues in 2000 versus a full year of revenues in 1999. This decrease was partially offset by the significant increase in the price of natural gas liquids in 2000.

Operating Expenses

PG&E NEG's operating expenses were $12.4 billion in 2001, a decrease of $4 billion or 24 percent from 2000. This decline in operating expenses occurred principally in PG&E NEG's energy trading business within the Integrated Energy and Marketing segment, and was mainly due to lower trade volumes and lower realized prices achieved primarily in the third and fourth quarters of 2001. These declines generally were due to higher commodity prices in the wake of the California energy crisis in the second half of 2000 and the decline in economic activity in the U.S. in the second half of 2001. In PG&E NEG's Pipeline segment, the decline in operating expenses of $797 million is primarily due to the sale of PG&E GTT in December 2000.

PG&E NEG's operating expenses were $16.4 billion in 2000, an increase of $3.4 billion or 26 percent from 1999. The increase in operating expenses, which occurred principally in the Integrated Energy and Marketing segment, was mainly due to the increased volume of electricity and other related products and the significantly higher prices of electricity in 2000. This increase was partially offset by lower fuel costs at generating facilities resulting from reduced fuel consumption. In PG&E NEG's Pipeline segment, an impairment charge of $1.3 billion was recognized in 1999 to reflect PG&E GTT's assets at their fair value. This impairment was based on a definitive agreement to sell the stock of PG&E GTT in January 2000. PG&E NEG recorded no comparable impairment or write-offs in 2000.

Dividends

PG&E Corporation's refinancing agreement prohibits dividends from being declared or paid until the term loans have been repaid. These loan agreements also preclude PG&E NEG from declaring dividends until the term loans have been repaid. The ringfencing transaction referred to above allows PG&E NEG to declare and pay dividends only if PG&E NEG meets certain financial coverage ratios and the dividend is unanimously approved by PG&E NEG's board of directors, which includes an independent director.

REGULATORY MATTERS

A significant portion of PG&E Corporation's operations is regulated by federal and state regulatory commissions. These commissions oversee service levels and in certain cases, PG&E Corporation's revenues and pricing for its regulated services. Following are the percentages of 2001 revenues that fell under the jurisdiction of these various regulatory agencies:

	Utility	Consolidated
Cost of service-based	96.6%	45.1%
Market	3.4%	54.9%

The Utility is the only subsidiary with significant regulatory proceedings at this time. The Utility's significant regulatory proceedings are discussed below. Regulatory proceedings associated with electric industry restructuring are discussed further in Note 3 of the Notes to the Consolidated Financial Statements.

1999 General Rate Case

The CPUC authorizes an amount known as "base revenues" to be collected from ratepayers to recover the Utility's basic business and operational costs for its gas and electric distribution operations. Base revenues, which include non-fuel-related operating and maintenance costs, depreciation, taxes, and a return on invested capital, currently are authorized by the CPUC in GRC proceedings.

In October 2001, the CPUC issued a decision granting applications for rehearing that had been filed by TURN and another party with respect to the CPUC's February 17, 2000, decision in the Utility's 1999 GRC for the period 1999 to 2001. The applications for rehearing, which had been pending since March 2000, alleged that the CPUC committed legal error by approving funding in certain areas that were not adequately supported by record evidence. In the rehearing decision, the CPUC found that in proposing a general rate increase, the Utility has the obligation to produce clear and convincing evidence for each component of its proposed revenue requirements. The CPUC reversed in part its prior determination regarding the adequacy of the evidence supporting the original 1999 GRC decision, reducing the adopted electric and gas distribution annual revenue requirement by approximately $24.4 million and $14.4 million, respectively.

In addition, the rehearing decision orders the record to be reopened to receive evidence of the actual level of 1998 electric distribution capital spending in relation to the forecast used to determine 1999 rates. This could possibly result in an adjustment of the adopted 1998 forecast level to conform to the 1998 recorded level.

Following the 1998 capital spending rehearing and resolution of all other outstanding matters, a final results of operations analysis will be performed, and a final revenue requirement will be determined. The rehearing decision apparently intends that the revised revenue requirement would be made retroactive to January 1, 1999. Further, in February 2002, the CPUC's consultants began an engineering audit of the Utility's 1999 distribution capital expenditures, as ordered in the CPUC's original February 17, 2000 decision regarding the 1999 GRC. The Utility does not expect a material impact on its financial position or results of operations from the remaining proceedings.

Some of the negative impact of the 1999 GRC rehearing decision was partially offset by a September 20, 2001, CPUC decision. In that decision the CPUC acknowledged that the models used to calculate certain tax items in the Utility's revenue requirements resulted in an incorrect calculation and granted an annual revenue requirements increase of approximately $21 million, representing an increase of $23 million in the gas distribution revenue requirement and a $2 million decrease in electric revenue requirement.

The revised gas revenue requirement resulting from both CPUC actions was retroactive to January 1, 1999, and resulted in a pre-tax income increase of $25.8 million in 2001. The electric revenue requirement charges were retroactive to January 1, 1999, and did not affect net income because the Utility has frozen electric rates.

On November 15, 2001, the Utility filed a petition for a review of the rehearing decision with the California Court of Appeal, as well as an application for rehearing of the rehearing decision with the CPUC. On January 9, 2002, the CPUC denied the Utility's application for rehearing of the rehearing decision.

2001 Attrition Rate Adjustment Request

On February 21, 2002, the CPUC issued a decision authorizing an increase in electric distribution revenue requirements of approximately $151 million, effective January 1, 2001. The increase reflects inflation and the growth in capital investments necessary to serve customers. The 2001 capital-related portion of the increase will be subject to a true-up based on the Utility's actual 2001 capital costs. The Utility did not request an increase in gas distribution revenue requirements. Because the Utility had frozen electric rates in 2001 the increase in electric distribution revenue requirements reduced the amount of revenues available to offset electric generation costs. Therefore, the decision has no material current earnings impact.

2003 GRC and 2002 ARA Request

The procedural schedule in the Utility's 2002 GRC, which would have determined revenue requirements for the period 2002 through 2004, has been delayed. On October 25, 2001, the CPUC issued a decision requiring the Utility to file a Notice of Intent (NOI) to file a 2003 test year GRC (rather than a 2002 test year) by November 14, 2001. The CPUC stated that its goal is to have new rates "in place" by January 1, 2003. A 2003 GRC will determine revenue requirements for the period 2003 through 2005.

In the October 25 order, the CPUC also requested that the Utility and others file comments by November 9, 2001, on the Utility's needs for a 2002 ARA. On November 9, 2001, the Utility filed comments stating its need for a 2002 ARA to allow for recovery of costs of providing electric and gas distribution services. The CPUC has not yet responded to these comments, and has not acknowledged either the Utility's proposal for a process to request an ARA, or the need for interim relief. To the extent the Utility's proposed 2002 ARA is similar to the ARA for 2001, the requested increase will reflect similar annual cost growth as shown in the Utility's 2001 ARA. However, the revenue increase authorized for 2002 will depend on both the amount authorized by the CPUC, and whether and when the CPUC authorizes interim relief. If the CPUC authorizes interim relief for the 2002 ARA, the authorized amount would be prorated for the period extending from the date of the interim authorization to the end of 2002. On January 17, 2002, the Utility filed a motion requesting that the CPUC issue an interim decision authorizing an interim relief mechanism. The Utility also requested that the CPUC specify a process to identify the amount of the ARA requested.

On November 14, 2001, the Utility informed the CPUC that is was impossible to file a fully compliant NOI based on a 2003 test year, considering that it normally takes at least six months to prepare the cost estimates and analyses necessary to develop test-year estimates. On December 11, 2001, the CPUC issued an order to show cause why the Utility should not be penalized for failing to submit the required NOI. The order stated that penalties could be imposed of up to $20,000 per each day the Utility fails to comply with the October 25, 2001, order. On December 20, 2001, the Utility filed a motion with the CPUC to submit its NOI for a 2003 GRC by April 15, 2002. The proposal includes, among other terms, an agreement to pay a voluntary fine of $500 per day beginning January 9, 2002, and concluding on the day the Utility submits its NOI. This proposal is the result of negotiations with the CPUC's staff members. The CPUC has not yet acted upon this proposal.

Retained Generation Ratemaking Proceeding

In June 2001, the Utility filed its proposed ratemaking for retained utility generation facilities and procurement costs still incurred by the Utility. The Utility's proposal requested that the ratemaking for its retained generating facilities be set in accordance with previous and still effective CPUC decisions under AB 1890. Absent the ability to make marketplace sales, the Utility believes AB 1890 allows the Utility to offset its transition costs by the market value in excess of the book value of the Utility's retained non-nuclear generating facilities, and to recover that market valuation in retail rates as a component of its retained generation rate based on a going forward basis. Accordingly, the Utility has submitted proposed market valuations of non-nuclear retained generation facilities, so that the facilities can be valued by the CPUC.

Further, the Utility believes that the ratemaking for the Utility's Diablo Canyon facility should be based on the specific "benefits sharing" formula established in a 1997 CPUC decision. Under the formula, the Utility would share with ratepayers 50 percent of the net operating benefits or costs of operating Diablo Canyon after the rate freeze.

The Incremental Cost Incentive Price (ICIP) ratemaking for Diablo Canyon used to recover the Diablo Canyon facility's operating costs and the cost of capital additions incurred after December 31, 1996 was originally scheduled to end December 31, 2001.

On January 18, 2002, the CPUC issued a proposed decision establishing the Utility's retained generation revenue requirement for 2002. The proposed decision adopts a cost-based 2002 generation revenue requirement for the Utility of $2,875 million subject to adjustment to reflect actual recorded costs (true-up). In addition, the proposed decision rejects the "benefits sharing" ratemaking for Diablo Canyon in favor of cost-based rates that will be subject to a "reasonableness" review in the next GRC. The proposed decision does not reset rates and substantially ignores the Utility's proposed ratemaking, including market-value based recovery for non-nuclear generating facilities and monthly true-ups of operating and maintenance costs.

On February 7, 2002, a CPUC Commissioner issued an alternate proposed decision (AD) regarding the Utility's retained generation revenue requirement proceeding which proposes not to reject benefits sharing for Diablo Canyon but would defer that decision to another proceeding. The AD also notes that the ICIP for Diablo Canyon would continue until the Utility has recovered its transition costs, and implies that ICIP is tied to recovery of transition costs. The AD also proposes a cost-based 2002 retained generation revenue requirement for the Utility of $2,875 million although it is not clear which costs would be subject to future adjustments.

In January 2001, the California Legislature passed AB 6X, which amended Public Utilities Code (PUC) Section 377 to prohibit utilities from divesting their retained generating plants before January 1, 2006. AB 6X did not amend PUC Section 367, which requires the CPUC to market value the generating assets of each utility by no later than December 31, 2001, based on appraisal, sale, or other divestiture. However, on December 21, 2001, a CPUC Commissioner issued a ruling indicating that in her opinion AB 6X supersedes PUC Section 367 to delete any requirement of market valuation for utility generation assets. On January 15, 2002, the Utility filed comments reiterating the reasons contained in previous pleadings as to why the enactment of AB 6X did not supersede or repeal the CPUC's statutory obligation to market value the Utility's generation assets by December 31, 2001.

On January 17, 2002, the Utility filed an administrative claim with the State of California Victim Compensation and Government Claims Board (Board) alleging that the January 2001 enactment of AB 6X violates the Utility's contractual rights under AB 1890. The Utility's claim seeks compensation for the denial of the Utility's right to at least $4.1 billion market value of its retained generating facilities in FERC-regulated interstate power markets. On February 22, 2002, the Board denied the Utility's claim. The Utility has six months from the date of the denial to file suit on this claim in California Superior Court.

The Utility cannot predict what the outcome of any of these proceedings will be or whether they will have a material adverse effect on its results of operations or financial condition.

Revenue Adjustment Proceeding

The CPUC established the Revenue Adjustment Proceeding (RAP) to verify amounts recorded in the Utility's Transition Revenue Account (TRA) and to verify authorized revenue requirements, including adjustments approved in other proceedings. The RAP also establishes revenue allocation and rate design, and identifies all electric balancing and memorandum accounts for continued retention or elimination.

In June 2001, the Utility filed its RAP application addressing revenues and costs recorded in the TRA from July 1, 1999, through April 30, 2001. A CPUC decision and related appeals are still pending.

Annual Transition Cost Proceeding

The Annual Transition Cost Proceeding (ATCP) was established to verify the accounting and recording of costs and revenues in the Transition Cost Balancing Account (TCBA), and ensure that only eligible transition costs have been entered. The TCBA tracks the revenues available to offset transition costs, including the accelerated recovery of plant balances, and other generation-related assets and obligations. Transition costs will receive a limited "reasonableness" review.

In September 2000, the Utility filed its 2000 ATCP application seeking approval of amounts recorded in the TCBA and generation memorandum accounts for the period July 1, 1999, through June 30, 2000. The CPUC has not yet issued a decision covering that period. In September 2001, the Utility filed its 2001 ATCP application seeking approval of the recorded amounts for the period July 1, 2000, through June 30, 2001.

ISO Tariff Creditworthiness Requirements

On January 19, 2001, the Utility was no longer able to continue purchasing power for its customers because of lack of creditworthiness, and as a result, the State of California authorized the DWR to purchase electricity for the Utility's customers. The ISO continued to bill the Utility for its power purchase costs that were incurred to cover the Utility's net open position not covered by the DWR. On February 14, 2001, the FERC ordered that the ISO could buy power only on behalf of creditworthy entities. On April 6, 2001, the FERC issued a further order directing the ISO to implement its prior order, which, the FERC clarified, applies to all third-party transactions whether scheduled or not. On June 13, 2001, the FERC denied the ISO's request for rehearing of its April 6, 2001, order.

The Utility has not recorded any estimated ISO charges after April 6, 2001, except for the ISO's grid management charge, although the Utility has accrued the full amount of the ISO charges of approximately $1 billion up to April 6, 2001.

On November 7, 2001, the FERC issued an order granting a motion by a group of generators to enforce the creditworthiness requirements of the ISO tariff and rejecting an amendment proposed by the ISO. The FERC noted that its prior February 14 and April 6, 2001, orders required a creditworthy counterparty for power purchases. The FERC stated that the ISO is obligated to invoice, collect payments from, and distribute payments to the DWR for all scheduled and unscheduled transactions on behalf of the DWR, including transactions where the DWR serves as the creditworthy counterparty for the applicable portion of the Utility's load. The November 7, 2001, order directs the ISO to (1) enforce its billing and settlement provisions under the ISO tariff, (2) invoice the DWR for all ISO transactions it entered into on behalf of the Utility and Southern California Edison within 15 days from the date of the order, with a schedule for payment of overdue amounts within three months, and (3) reinstate the billing and settlement provisions under the tariff.

Subsequently, the ISO has issued invoices to the DWR for the amounts in dispute. The DWR is in the process of paying substantially all such invoices for the period from January 17, 2001, forward. On December 7, 2001, the DWR filed an application for rehearing of the FERC order, alleging, among other things, that the FERC order was illegal and unconstitutional because it restricted the DWR's unilateral discretion to determine the prices it would pay for third party power under the ISO invoices. If the FERC upholds its previous ruling that the DWR, not the Utility, is responsible for amounts billed by the ISO to the DWR for the period from January 17, 2001, through April 6, 2001, the Utility will reverse the $1 billion accrued during 2001. However, if the Utility reverses the ISO accrual, it would need to record an accrual for its obligations to the DWR for such purchases. The Utility expects that this DWR accrual would not exceed the ISO reversal.

FERC Prospective Price Mitigation Relief

The FERC issued a series of significant orders in the spring and summer of 2001 that prescribed prospective price mitigation relief. On April 26, 2001, the FERC issued an order that prescribed price mitigation for those hours in which the ISO declared an emergency. The order also imposed a requirement that all generators in California offer available generation for sale to the ISO's real-time energy market during all hours. While the Utility recognized the importance of the FERC's action, it sought rehearing of the April 26, 2001, order on the premise that the price mitigation methodology could be made more comprehensive, both in terms of the hours in which it was to be applied and the types of transactions that it covered.

In June 2001, the FERC further ordered prospective price mitigation for the wholesale spot markets throughout both California and the Western Systems Coordinating Council (WSCC) that established the current mitigation methodology going forward. Features of this current methodology include:

1. Its extension to all hours of the day,
2. The reaffirmation of its requirement that all generators in California offer available generation for sale to the ISO's real-time energy market,
3. The establishment of a single market clearing price in the ISO's spot markets during emergency hours, and
4. The establishment of a maximum market clearing price for spot market sales in all hours.

In June and July 2001, the FERC's chief ALJ conducted settlement negotiations among power generators, the State of California, and the California investor-owned utilities, in an attempt to resolve disputes regarding past power sales. The State represented that it and the California investor-owned utilities are owed $8.9 billion for electricity overcharges by the generators. The negotiations did not result in a settlement, but the judge recommended that the FERC conduct further hearings to determine what the power sellers and buyers are each owed. The Utility does not believe these matters will be resolved until mid- to late 2002, nor can it predict whether a refund will be ordered or the amount the Utility might receive. In connection with this proceeding, on August 17, 2001, the ISO submitted data indicating that a PG&E NEG affiliate, PG&E Energy Trading- Power, L.P. (ET Power) may be required to refund approximately $26 million. However, the FERC has indicated that unpaid amounts owed by the ISO and the PX may be used as offsets to any refund obligations. Potential offsets would significantly reduce any potential refund required to be made by ET Power. Finalization of any refunds and offsets are subject to the on-going FERC proceeding.

Direct Access Service

Until September 20, 2001, California's restructured electricity market gave customers the option of subscribing either to "bundled service" from the Utility or "direct access" service from an ESP. Direct access customers receive distribution and transmission service from the Utility, but purchase electricity (generation) from their ESP. Customers receiving bundled services receive distribution, transmission, and generation services from the Utility. On September 20, 2001, the CPUC, pursuant to AB 1X, suspended the right of retail end-use customers to acquire direct access service thereby preventing additional customers from entering into contracts to purchase electricity from outside service providers. The decision did not address agreements entered into before September 29, 2001, including renewals of such contracts or agreements, and stated that such issues would be addressed in a subsequent decision. On January 25, 2002, the CPUC issued a proposed decision that, if made final, will suspend direct access retroactive to July 1, 2001. In addition to making void all direct access contracts entered into on or after July 1, 2002, the proposed decision prevents customers with valid direct access contracts entered into prior to this date from switching service providers, adding locations, or renewing the terms of such contracts. An alternate proposed decision maintains the original direct access suspension date of September 20, 2001. The comment period for the proposed decision expired February 14, 2002.

The Utility's ability to recover incurred generation costs is affected by the amount of generation-related revenues the Utility is able to collect. To the extent that the Utility's customers elect direct access service, they do not pay generation-related revenue to the Utility. Direct access credits totaled $461 million in 2001. See the "Results of Operations—Electric Revenue" section for a discussion of direct access credits.

Cost of Capital Proceedings

Each year, the Utility files an application with the CPUC to determine the authorized rate of return that the Utility may earn on its electric and gas distribution assets and recover from ratepayers. Since February 17, 2000, the Utility's adopted return on common equity (ROE) has been 11.22 percent on electric and gas distribution operations, resulting in an authorized 9.12 percent overall rate of return (ROR). The Utility's earlier adopted ROE was 10.6 percent. In May 2000, the Utility filed an application with the CPUC to establish its authorized ROR for electric and gas distribution operations for 2001. The application requests a ROE of 12.4 percent and an overall ROR of 9.75 percent. If granted, the requested ROR would increase 2001 electric and gas distribution revenues by approximately $72 million and $23 million, respectively. The application also requests authority to implement an Annual Cost of Capital Adjustment Mechanism for 2002 through 2006 that would replace the annual cost of capital proceedings. The proposed adjustment mechanism would modify the Utility's cost of capital based on changes in an interest rate index. The Utility also proposes to maintain its currently authorized capital structure of 46.2 percent long-term debt, 5.8 percent preferred stock, and 48 percent common equity. In March 2001, the CPUC issued a proposed decision recommending no change to the current 11.22 percent ROE for test year 2001. A final CPUC decision is pending.

FERC Transmission Rate Cases

Electric transmission revenues and both wholesale and retail transmission rates are subject to authorization by the FERC. The FERC has not yet acted upon a settlement filed by the Utility that, if approved, would allow the Utility to recover $391 million in electric transmission rates for the 14-month period of April 1, 1998, through May 31, 1999. During this period, somewhat higher rates have been collected, subject to refund. A FERC order approving this settlement is expected by the end of 2002. The Utility has accrued $29 million for potential refunds related to the 14-month period ended May 31, 1999.

In July 2001, the FERC approved a settlement that permits the Utility to collect $262 million annually, (net of the 2002 Transmission Revenue Balancing Account) in electric transmission rates beginning on May 6, 2001. This decrease in transmission rates relative to previous time periods is due to unusually large balances paid to the Utility by the ISO for congestion management charges and other transmission-related services billed by the ISO that are booked in the Transmission Revenue Balancing Account. These balances paid by the ISO are offset against the Utility's transmission revenue requirement. The Utility does not expect the outcome of these settlements to have a material adverse effect on its results of operations or financial condition.

In March 2001, the Utility filed at the FERC to increase its power and transmission-related rates to the Western Area Power Administration (WAPA). The majority of the requested increase is related to passing through market power prices billed to the Utility by the ISO and others for services, which apply to WAPA under a pre-existing contract between the Utility and WAPA. On September 21, 2001, the FERC ALJ issued an Initial Decision denying the Utility the ability to increase the rates as requested. On October 24, 2001, the FERC confirmed the ALJ's Initial Decision in its entirety. The FERC denied the Utility's November 21, 2001, request for rehearing, and that decision has been appealed to the U.S. Court of Appeals for the D.C. Circuit. Pending a decision from the Court, until December 31, 2004, the date the WAPA contract expires, WAPA's rates will continue to be calculated on a yearly basis pursuant to the formula specified in WAPA's contract under AB 1890. Any revenue shortfall or benefit resulting from this contract is included in rates through the end of the contract period as a purchased power cost.

Scheduling Coordinator Costs

In connection with electric industry restructuring, the ISO was established to provide operational control over most of the state's electric transmission facilities and to provide comparable open access for electric transmission service. The Utility serves as the scheduling coordinator to schedule transmission with the ISO to facilitate continuing service under existing wholesale transmission contracts that the Utility entered into before the ISO was established. The ISO bills the Utility for providing certain services associated with these contracts. These ISO charges are referred to as the "scheduling coordinator (SC) costs."

As part of the Utility's Transmission Owner rate case filed at the FERC, the Utility established the Transmission Revenue Balancing Account (TRBA) to record these SC costs in order to recover these costs through transmission rates. Certain transmission-related revenues collected by the ISO and paid to the Utility are also recorded in the TRBA. Through December 31, 2001, the Utility had recorded approximately $110 million of these SC costs in the TRBA. (The Utility has also disputed approximately $27 million of these costs as incorrectly billed by the ISO. Any refunds that ultimately may be made by the ISO would be credited to the TRBA.)

In September 1999, an ALJ of the FERC issued a proposed decision denying recovery of these SC costs from retail and new wholesale customers in the TRBA. The ALJ indicated that the Utility should try to recover these costs from existing wholesale customers. The proposed decision is subject to change by the FERC in its final decision. The FERC is expected to issue a final decision in 2002. In January 2000, the FERC accepted a proposal by the Utility to establish the Scheduling Coordinator Services (SCS) Tariff. The SCS Tariff would serve as a back-up mechanism for recovery of the SC costs from existing wholesale customers if the FERC ultimately decides that these costs may not be recovered in the TRBA. The FERC also conditionally granted the Utility's request that the SCS Tariff be effective retroactive to March 31, 1998. However, the FERC suspended the procedural schedule until the final decision is issued regarding the inclusion of SC costs in the TRBA.

The Utility does not expect the outcome of this proceeding to have a material adverse effect on its results of operations or financial condition.

Gas Accord II Application

Under a ratemaking pact called the Gas Accord, implemented in March 1998, the Utility's gas transmission services were separated or unbundled from its distribution services, and the terms of service and rate structure for gas transportation were changed. The Gas Accord also allows core customers to purchase gas from competing suppliers, establishes an incentive mechanism to measure the reasonableness of core procurement costs, and establishes gas transmission and storage rates through 2002. On October 9, 2001, the Utility filed a Gas Accord II application with the CPUC, requesting a two-year extension, without modification to the terms and conditions of the existing Gas Accord. In return, the Utility will forego its ability under the original Gas Accord to increase rates 2.5 percent annually during the extended time period.

Under the Utility's proposal, those provisions of the Gas Accord currently scheduled to expire on January 1, 2003, will be extended through December 31, 2004, while certain storage-related provisions scheduled to expire on April 1, 2003, will be extended through March 31, 2005. No change is proposed to the previously approved rates in effect as of December 2002 or, in the case of certain storage provisions, as of March 31, 2003. The Utility believes the two-year extension that has been proposed will allow for resolution of many uncertainties affecting gas markets today, including the Utility's proposed plan of reorganization. The CPUC has not issued a decision in this proceeding. The Utility cannot predict what the outcome of the decision will be, or whether the outcome will have a material adverse effect on its results of operations or financial condition.

Federal Lawsuit

On November 8, 2000, the Utility filed a lawsuit in federal District Court in San Francisco against the CPUC Commissioners. The Utility asked the District Court to declare that the federally approved wholesale electricity costs that the Utility has incurred to serve its customers are recoverable in retail rates both before and after the end of the transition period. The lawsuit stated that the wholesale power costs that the Utility has incurred are paid pursuant to filed tariffs, which the FERC has authorized and approved, and that under the United States Constitution and numerous federal court decisions, state regulators cannot disallow such costs. The Utility's lawsuit also alleged that to the extent the Utility is denied recovery of these mandated wholesale electricity costs by order of the CPUC, such action constitutes an unlawful taking and confiscation of the Utility's property.

On May 2, 2001, the District Court dismissed the Utility's complaint, without prejudice to refile the lawsuit at a later time, on the ground that the suit was premature since two of the challenged CPUC decisions were not yet final. On August 6, 2001, the Utility refiled its complaint in the U.S. District Court for the Northern District of California, based on the fact that the CPUC's decisions referenced in the District Court's order had become final under California law. The CPUC and TURN have filed motions to dismiss the complaint. On November 26, 2001, the case was transferred to a District Court in the Northern District of California and consolidated as a related case with the Utility's appeal of the Bankruptcy Court's denial of the Utility's request for injunctive and declaratory relief against the retroactive accounting order adopted by the CPUC in March 2001. A case management conference in both actions is scheduled for March 7, 2002.

Order Instituting Investigation (OII) into Holding Company Activities and Related Litigation

On April 3, 2001, the CPUC issued an OII into whether the California investor-owned utilities, including the Utility, have complied with past CPUC decisions, rules, or orders authorizing their holding company formations and/or governing affiliate transactions, as well as applicable statutes. The order states that the CPUC will investigate (1) the utilities' transfer of money to their holding companies since deregulation of the electric industry commenced, including during times when their utility subsidiaries were experiencing financial difficulties, (2) the failure of the holding companies to financially assist the utilities when needed, (3) the transfer by the holding companies of assets to unregulated subsidiaries, and (4) the holding companies' action to "ringfence" their unregulated subsidiaries. The CPUC will also determine whether additional rules, conditions, or changes are needed to adequately protect ratepayers and the public from dangers of abuse stemming from the holding company structure. The CPUC will investigate whether it should modify, change, or add conditions to the holding company decisions, make further changes to the holding company structure, alter the standards under which the CPUC determines whether to authorize the formation of holding companies, otherwise modify the decisions, or recommend statutory changes to the California Legislature. As a result of the investigation, the CPUC may impose remedies, prospective rules, or conditions, as appropriate.

On January 9, 2002, the CPUC issued an interim decision interpreting the "first priority condition" adopted in the CPUC's holding company decisions (the condition that the capital requirements of the utility, as determined to be necessary and prudent to meet the utility's obligation to serve or operate the utility in a prudent and efficient manner, be given first priority by the board of directors of the holding company). In the interim decision, the CPUC concluded that the condition, at least under certain circumstances, includes the requirement that each of the holding companies "infuse the utility with all types of capital necessary for the utility to fulfill its obligation to serve." The CPUC also interpreted the first priority condition as prohibiting a holding company from (1) acquiring assets of its utility subsidiary for inadequate consideration, and (2) acquiring assets of its utility subsidiary at any price, if such acquisition would impair the utility's ability to fulfill its obligation to serve or to operate in a prudent and efficient manner.

In a related decision, the CPUC denied the motions filed by the California utility holding companies to dismiss the holding companies from the pending investigation on the basis that the CPUC lacks jurisdiction over the holding companies. However, in the decision interpreting the first priority condition discussed above, the CPUC separately dismissed PG&E Corporation (but no other utility holding company) as a respondent to the proceeding. In its written decision mailed on January 11, 2002, the CPUC stated that PG&E Corporation was being dismissed so that an appropriate legal forum could decide expeditiously whether adoption of the Utility's proposed plan of reorganization would violate the first priority condition.

On January 10, 2002, the California Attorney General filed a complaint in the San Francisco Superior Court against PG&E Corporation and its directors, as well as against the directors of the Utility, alleging PG&E Corporation violated various conditions established by the CPUC and engaged in other unfair or fraudulent business practices or acts. The Attorney General also alleges that the December 2000 and January and February 2001 ringfencing transactions by which PG&E Corporation subsidiaries complied with credit rating agency criteria to establish independent credit ratings violated the holding company conditions.

In a press release issued on January 10, 2002, the CPUC expressed support for the Attorney General's complaint, noting that the CPUC's January 9, 2002, decision provided a basis for the Attorney General's allegations and that the CPUC intends to join in a lawsuit against PG&E Corporation based on these issues.

Among other allegations, the Attorney General alleges that, through the Utility's bankruptcy proceedings, PG&E Corporation and the Utility engaged in unlawful, unfair and fraudulent business practices by seeking to implement the transactions proposed in the proposed plan of reorganization filed in the Utility's bankruptcy proceeding. The complaint also seeks restitution of assets allegedly wrongfully transferred to PG&E Corporation from the Utility. The Bankruptcy Court has original and exclusive jurisdiction of these claims. Therefore, on February 8, 2002, PG&E Corporation filed a notice of removal in the Bankruptcy Court to transfer the Attorney General's complaint to the Bankruptcy Court. On February 15, 2002, a motion to dismiss the lawsuit or in the alternative to stay the suit, was filed.

On February 11, 2002, a complaint entitled, City and County of San Francisco; People of the State of California v. PG&E Corporation, and Does 1-150, was filed in San Francisco Superior Court. The complaint contains some of the same allegations contained in the Attorney General's complaint including allegations of unfair competition. In addition, the complaint alleges causes of action for (1) conversion, claiming that PG&E Corporation "took at least $5.2 billion from the Utility," and (2) "unjust enrichment."

The complaint seeks injunctive relief, the appointment of a receiver, restitution, disgorgement, the imposition of a constructive trust, civil penalties, and costs of suit.

PG&E Corporation and the Utility believe that they have complied with applicable statutes, CPUC decisions, rules, and orders. Neither the Utility nor PG&E Corporation, however, can predict what the outcome of the CPUC's investigation will be or whether the outcome will have a material adverse effect on their results of operations or financial condition. PG&E Corporation will vigorously respond to and defend the litigation.

State of California Senate Bill X2

The statutory end of the transition period is March 31, 2002. In September 2001, California Senate Bill (SB) X2 was passed which prohibits the CPUC from raising rates for residential and small commercial customers solely as a result of the statutory end of the rate freeze. In conjunction with the end of the transition period, the Utility will discontinue deferring generation-related costs associated with its 10 percent rate reduction provided to certain customers. During the transition period, the Utility provided the 10 percent rate reduction by financing a portion of its generation-related costs with Rate Reduction Bonds (see Note 10 for a description of Rate Reduction Bonds). In accordance with AB 1890, these financed generation-related transition costs were deferred to the Rate Reduction Bond regulatory asset. The Rate Reduction Bond regulatory asset will be recovered after the end of the transition period through fixed transition revenues. Also, in the first quarter of 2002, the Utility will begin amortizing its Rate Reduction Bond regulatory asset. This amortization will be approximately $290 million per year and will be offset against fixed transition revenues. In 2001, fixed transition revenues were included in the generation component of electric rates and contributed to the excess of generation-related revenues over generation-related costs.

Annual Earnings Assessment Proceeding (AEAP)

The Utility administers general and low income energy efficiency programs funded through a public goods component in customers' rates. The Utility receives incentives for this activity, including incentives based on a portion of the net present value of the savings achieved by the programs, incentives based on accomplishing certain tasks, and incentives based on expenditures. Annually, the Utility files an earnings claim in the AEAP, a forum for stakeholders to comment on and for the CPUC to evaluate the Utility's claim verification.

In May 2000, PG&E filed its 2000 AEAP application, which establishes incentives to be collected during 2001. The CPUC has delayed action on the Utility's 2000 AEAP and joined the 2000 AEAP with the Utility's 2001 AEAP. The third pre-hearing conference for the joint proceeding is scheduled for February 2002. The Utility claim for shareholder incentives in this combined proceeding is approximately $80 million. The Utility has not reflected incentives in the Utility's Consolidated Statements of Operations for the year ended December 31, 2001.

In the 1999 AEAP, which established incentives to be collected in 2000, the CPUC authorized incentives of approximately $26 million. These incentives are reflected in the Utility's Consolidated Statements of Operations for the year ended December 31, 2000.

The Utility expects to file with the CPUC its 2002 AEAP application in May 2002.

ENVIRONMENTAL MATTERS

PG&E Corporation and the Utility are subject to laws and regulations established to both 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 require PG&E Corporation and the Utility to remove those substances or remedy effects on the environment. See Note 16 of the Notes to the Consolidated Financial Statements for further discussion of environmental matters.

Utility

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, 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 or disposal of potentially hazardous materials. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances, even if it did not deposit those substances on the site.

The Utility records an environmental remediation liability when site assessments indicate remediation is probable and a range of reasonably likely clean-up costs can be estimated. The Utility reviews its remediation liability quarterly for each identified site. The liability is an estimate of costs for site investigations, remediation, operations and maintenance, monitoring, and site closure using (1) current technology, (2) enacted laws and regulations, (3) experience gained at similar sites, and (4) 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 lower end of this range.

Hazardous Waste Remediation

The Utility had an environmental remediation liability of $295 million and $320 million at December 31, 2001, and 2000, respectively. The $295 million accrued at December 31, 2001, includes (1) $139 million related to the pre-closing remediation liability, associated with divested generation facilities, and (2) $156 million related to remediation costs for those generation facilities that the Utility still owns, manufactured gas plant sites, and gas gathering compressor stations. Of the $295 million environmental remediation liability, the Utility has recovered $193 million through rates, and expects to recover the balance in future rates. The Utility also is recovering its costs from insurance carriers and from other third parties as appropriate.

On June 28, 2001, the Bankruptcy Court authorized the Utility to continue its hazardous waste remediation program and to expend:

- Up to $22 million in each calendar year in which the Chapter 11 case is pending to continue its hazardous substance remediation programs and procedures, and
- Any additional amounts necessary in emergency situations involving post-petition releases or threatened releases of hazardous substances, subject to the Bankruptcy Court's specific approval.

At December 31, 2001, the Utility estimates total future costs for hazardous waste remediation at identified sites, including divested fossil-fueled power plants to be $295 million (undiscounted). The cost of the hazardous substance remediation ultimately undertaken by the Utility is difficult to estimate. A change in the estimate 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. If other potentially responsible parties are not financially able to contribute to these costs or further investigation indicates that the extent of contamination or necessary remediation is greater than anticipated, the Utility's future cost could increase by as much as $446 million. The Utility estimates the upper limit of the range using assumptions least favorable to the Utility, based upon a range of reasonably possible outcomes. Costs may be higher if the Utility is found to be responsible for clean-up costs at additional sites or expected outcomes change.

Environmental Claims

The California Attorney General, on behalf of various state environmental agencies, filed claims in the Utility's bankruptcy proceeding for environmental remediation at numerous sites aggregating to approximately $770 million. For most if not all of these sites, the Utility is in the process of remediation in cooperation with the relevant agencies or would be doing so in the future in the normal course of business. In addition, for the majority of the remediation claims, the state would not be entitled to recover these costs unless they accept responsibility to clean up the sites, which is unlikely. Since the proposed plan of reorganization provides that the Utility intends to respond to these types of claims in the regular course of business, and since the Utility has not argued that the bankruptcy proceeding relieves the Utility of its obligations to respond to valid environmental remediation orders, the Utility believes the claims seeking specific cash recoveries are invalid.

Moss Landing

In December 1999, the Utility was notified by the purchaser of its former Moss Landing power plant that it had violated the plant's National Pollutant Discharge Elimination System (NPDES) permit issued by the Central Coast Regional Water Quality Control Board (Central Coast Board). A claim has been filed by the California Attorney General in the Utility's bankruptcy proceeding on behalf of the Central Coast Board seeking unspecified penalties.

Diablo Canyon

The Utility's Diablo Canyon generating facility employs a "once through" cooling water system, which is regulated under a NPDES permit issued by the Central Coast Board. This permit allows Diablo Canyon to discharge the cooling water at a temperature no more than 22 degrees above ambient receiving water and requires that the beneficial uses of the water be protected. The beneficial uses of water in this region include industrial water supply, marine and wildlife habitat, shellfish harvesting, and preservation of rare and endangered species. In January 2000, the Central Coast Board issued a proposed draft Cease and Desist Order alleging that, although the temperature limit has never been exceeded, Diablo Canyon's discharge was not protective of beneficial uses. In October 2000, the Central Coast Board and the Utility reached a tentative settlement of this matter pursuant to which the Central Coast Board has agreed to find that the Utility's discharge of cooling water from the Diablo Canyon plant protects beneficial uses and that the intake technology reflects the "best technology available" under Section 316(b) of the Federal Clean Water Act. As part of the settlement, the Utility will take measures to preserve certain acreage north of the plant and will fund approximately $5 million in environmental projects related to coastal resources. The parties are negotiating the documentation of the settlement. The final agreement will be subject to public comment and will be incorporated in a consent decree to be entered in California Superior Court. A claim has been filed by the California Attorney General in the Utility's bankruptcy proceeding on behalf of the Central Coast Board seeking unspecified penalties and other relief in connection with Diablo Canyon's operation of its cooling water system.

The Utility believes the ultimate outcome of these matters will not have a material impact on its financial position or results of operations.

PG&E NEG

PG&E NEG anticipates spending up to approximately $337 million, net of insurance proceeds from 2002, through 2008 for environmental compliance at currently operating facilities. To date, PG&E NEG has spent approximately $8 million of this amount. PG&E NEG believes that a substantial portion of this amount will be funded from its operating cash flow. This amount may change, however, and the timing of any necessary capital expenditures could be accelerated in the event of a change in environmental regulations or the commencement of any enforcement proceeding against PG&E NEG.

In May 2000, PG&E NEG received an Information Request from the U.S. Environmental Protection Agency (EPA), pursuant to Section 114 of the Federal Clean Air Act (CAA). The Information Request asked PG&E NEG to provide certain information relative to the compliance of the Brayton Point and Salem Harbor Generating Stations with the CAA. No enforcement action has been brought by the EPA to date. PG&E NEG has had very preliminary discussions with the EPA to explore a potential settlement of this matter. As a result of this and related regulatory initiatives by the Commonwealth of Massachusetts, PG&E NEG is exploring initiatives that would assist it to achieve significant reductions of sulfur dioxide, nitrogen oxide, and thermal emissions by 2006. PG&E NEG believes that it would meet these requirements through installation of controls at the Brayton Point and Salem Harbor plants and estimates that capital expenditures on these environmental projects will be approximately $266 million over the next five years. PG&E NEG believes that it is not possible to predict at this point whether any such settlement will occur or, in the absence of a settlement, the likelihood of whether the EPA will bring an enforcement action.

PG&E Gen's existing power plants, including USGen New England, Inc. (USGenNE) facilities, are subject to federal and state water quality standards with respect to discharge constituents and thermal effluents. Three of the fossil-fueled plants owned and operated by USGenNE are operating pursuant to NPDES permits that have expired. For the facilities whose NPDES permits have expired, permit renewal applications are pending, and it is anticipated that all three facilities will be able to continue to operate under existing terms and conditions until new permits are issued. It is estimated that USGenNE's cost to comply with the new permit conditions could be as much as $67 million through 2005. It is possible that the new permits may contain more stringent limitations than prior permits.

In September 2000, USGenNE signed a series of agreements that require it to alter its existing wastewater treatment facilities at the Brayton Point and Salem Harbor generating facilities. Through December 31, 2001, USGenNE has incurred approximately $8 million and expects that total costs will be approximately $18 million. Certain of these costs have been capitalized and a receivable has been recorded for amounts it believes are probable of recovery through insurance proceeds.

Inflation

Financial statements, which are prepared in accordance with accounting principles generally accepted in the United States of America, report operating results in terms of historical costs and do not evaluate the impact of inflation. Inflation affects our construction costs, operating expenses, and interest charges. In addition, the Utility's electric revenues do not reflect the impact of inflation due to the current electric rate freeze. However, inflation at current levels is not expected to have a material adverse impact on PG&E Corporation's or the Utility's financial position or results of operations.

Quantitative and Qualitative Disclosures About Market Risk

Risk Management Activities

PG&E Corporation and the Utility have established risk management policies that allow the use of energy, financial, and weather derivative instruments (a derivative is a contract whose value is dependent on or derived from the value of some underlying asset) and other instruments and agreements to be used to manage its exposure to market, credit, volumetric, regulatory, and operational risks. PG&E Corporation and the Utility use derivatives for both trading (for profit) and non-trading (hedging) purposes. Trading activities may be done for purposes of gathering market intelligence, creating liquidity, maintaining a market presence, and taking a market view. Non-trading activities may be done for purposes of mitigating the risks associated with an asset (natural position embedded in asset ownership and regulatory requirements), liability, committed transaction, or probable forecasted transaction. Such derivatives include forward contracts, futures, swaps, options, and other contracts.

PG&E Corporation and the Utility may engage in the trading of derivatives only in accordance with policies set forth by the PG&E Corporation Risk Policy Committee. Trading is permitted only after PG&E Corporation's Risk Policy Committee approves appropriate limits for such activity and the organizational unit proposing this activity successfully demonstrates that there is a business need for such activity and that the market risks will be adequately measured, monitored, and controlled. PG&E Corporation's Risk Policy Committee is responsible for the overall approval of the Risk Management Policy and the delegation of approval and authorization levels. The Risk Policy Committee is comprised of senior executives who receive updates on market conditions, risk positions, credit exposures and overall results. Under PG&E Corporation, both PG&E NEG and the Utility have their own Risk Management Committees that address matters relating to those companies' respective businesses. These Risk Management Committees are also comprised of senior officers.

PG&E Corporation applies mark-to-market accounting to all of its trading activities, under the guidance in Emerging Issues Task Force (EITF) Issue No. 98-10, "Accounting for Contracts Involving Energy Trading and Risk Management Activities," which are recorded at fair value with realized and unrealized gains (losses) in earnings. The recognized but unrealized balances are recorded on the Consolidated Balance Sheets as price risk management assets and liabilities. Non-trading contracts that meet the definition of a derivative under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," may be classified as normal purchases and sales or cash flow hedges. Those derivatives that qualify for normal purchases and sales treatment are exempt from the fair value requirements of SFAS No. 133. Derivatives that are designated and qualify for cash flow hedge treatment are tested for their effectiveness in hedging the underlying position. Gains or losses associated with the hedge effectiveness are recorded on the Consolidated Balance Sheets in Other Comprehensive Income (OCI) and are reclassified into earnings in the period in which the underlying transaction affects earnings. Gains and losses associated with the ineffective portion of such hedges are recognized in earnings immediately. PG&E Corporation, through PG&E NEG, participates in trading and non-trading activities; the Utility participates only in non-trading activities.

The activities affecting the estimated fair value of trading activities, are presented below:

	(in millions)
Fair values of trading contracts at January 1, 2001	$ 199
Net gain on contracts settled during the period	(296)
Fair value of new trading contracts when entered into	—
Changes in fair values attributable to changes in valuation techniques and assumptions	—
Other changes in fair values	130
Fair values of trading contracts outstanding at December 31, 2001	33
Fair value of non-trading contracts	63
Net price risk management assets at December 31, 2001	$ 96

PG&E Corporation estimated the gross mark-to-market value of its trading contracts as of December 31, 2001, using the mid-point of quoted bid and ask prices, where available, and other valuation techniques when market data was not available (e.g. illiquid markets or products). In such instances, PG&E Corporation utilizes alternative pricing methodologies, including, but not limited to, third party pricing curves, the extrapolation of forward pricing curves using historically reported data or interpolating between existing data points. Most of PG&E Corporation's risk management models are reviewed by or purchased from third party experts with extensive experience in specific derivative applications. Fair value contemplates the effects of credit risk, liquidity risk, and time value of money on gross mark-to-market positions through the application of reserves.

The following table shows the sources of prices used to calculate the fair value of trading contracts at December 31, 2001. In many cases, these prices are fed into option models that calculate a gross mark-to-market value from which fair value is derived after considering reserves for liquidity, credit, time value, and model confidence.

Source of Fair Value (in millions)	Fair Value of Trading Contracts: Maturity Less Than One Year	Maturity One-Three Years	Maturity Four-Five Years	Maturity in Excess of Five Years	Total Fair Value
Prices actively quoted	$142	$ 11	$(18)	$19	$ 154
Prices provided by other external sources	—	—	—	19	19
Prices based on models and other valuation methods	(49)	(73)	(22)	4	(140)
Total	$ 93	$(62)	$(40)	$42	$ 33

The amounts disclosed above are not indicative of likely future cash flows, as these positions may be changed by new transactions in the trading portfolio at any time in response to changing market conditions, market liquidity, and PG&E Corporation's risk management portfolio needs and strategies.

Market Risk

To the extent that PG&E Corporation and the Utility have an open position (an open position is a position that is either not hedged or only partially hedged), it is exposed to the risk that fluctuations in commodity, futures and basis prices may impact financial results. Such risks include any and all change in value whether caused by trading positions, asset ownership/availability, debt covenants, exposure concentration, currency, weather, etc. regardless of accounting method. Market risk is also affected by changes in volatility, correlation and liquidity. We manage our exposure to market fluctuations within the risk limits provided for in the PG&E Corporation Risk Management Policy and minimize forward value fluctuations through hedging (i.e., selling plant output, buying fuel, utilizing transportation and transmission capacity) and portfolio management.

Commodity Price Risk

Commodity price risk is the risk that changes in market prices of a commodity for physical delivery will adversely affect earnings and cash flows.

Utility Electric Commodity Price Risk

In compliance with regulatory requirements, the Utility manages commodity price risk independently from the activities in PG&E Corporation's unregulated businesses. Because of different regulatory incentives and ratemaking methods, the Utility reports its commodity price risk separately for its electricity and natural gas businesses. Price risk management strategies consist primarily of the use of physical forward purchases and non-trading financial instruments to attain our objective of reducing the impact of commodity price fluctuations for electricity and natural gas associated with the Utility's procurement obligations to meet its retail electricity and natural gas loads. While the use of these instruments has been authorized by the CPUC, the CPUC has yet to establish rules around how it will judge the reasonableness of these instruments for electricity purchases. Gains and losses associated with the use of the majority of these financial instruments primarily affect regulatory accounts, depending on the business unit and the specific program involved.

The Utility has had a very limited ability to enter into forward contracts to hedge its exposure to commodity price fluctuations because of the reluctance of counterparties to extend credit. As the Utility's credit rating dropped below investment grade in January 2001, the DWR began purchasing wholesale power for electric customers on behalf of the state of California. The Utility is currently paying the DWR the amount of money it collects in retail generation rates for electricity purchased by the DWR for the net open position. The Utility believes that it is obligated to remit only these revenues to the DWR and, therefore, there is no price risk for electricity purchases to serve the net open position.

As explained in Note 2 of the Notes to the Consolidated Financial Statements, on September 20, 2001, PG&E Corporation and the Utility filed a proposed plan of reorganization of the Utility with the Bankruptcy Court. Upon the effective date of the Plan, the reorganized Utility will transfer its generation assets to Gen. Gen will operate as an independent power producer thereafter. As an independent owner/operator, Gen could face increased price risk associated with variability in power prices. Additionally, the reorganized Utility could face price risk if and when it resumes the net open position not already provided for by the DWR's contracts. The Plan proposes that the Reorganized Utility may reassume this responsibility at an unknown future date when certain specified conditions are met, including receiving an investment grade credit rating. To manage electric commodity price risk for both companies and to provide a sufficiently stable framework for financing, Gen proposes to sell its generation output to the reorganized Utility under a power sales agreement having a term of 12 years. As a result, during the term of the agreement, the price risk should be limited to replacement power requirements, if any, brought about by low hydroelectric availability and/or unit outages that may occur.

Utility Natural Gas Commodity Price Risk

Under a ratemaking method called the Core Procurement Incentive Mechanism (CPIM), the Utility recovers in retail rates the cost of procuring natural gas for its customers as long as the costs are within a 99 percent to 102 percent "dead-band" of a benchmark price. The CPIM benchmark price reflects a weighting of prescribed daily and monthly gas price indices that are representative of Utility gas purchases. Ratepayers and shareholders share costs or savings outside the "dead-band" equally. In addition, the Utility has contracts for capacity on various gas pipelines. There is price risk related to the Transwestern gas pipeline to the extent that unused portions of the pipeline are brokered at floating rates.

Under a ratemaking pact called the Gas Accord, currently scheduled to be in effect through December 2002, shareholders are at risk for any revenues from the sale of capacity on the Utility's pipelines and gas storage fields held by the California Gas Transmission (CGT) business unit. According to the terms of the Gas Accord, a portion of the pipeline and storage capacity is sold at competitive market-based rates. The Utility is generally exposed to reduced revenues when the price spreads between two delivery points narrow. In addition, the Utility is generally exposed to reduced revenues when throughput volumes are lower than expected, primarily caused by temperature and precipitation effects or by economy-driven impacts. On October 9, 2001, the Utility filed another Gas Accord application with the CPUC requesting a two-year extension without modification to existing terms and conditions of the existing Gas Accord. In return, the Utility will forego its ability to increase rates 2.5 percent annually during the extended time period. It is unclear when the CPUC will act upon the Utility's proposal.

PG&E NEG Commodity Price Risk

PG&E NEG is exposed to commodity price risk of its portfolio of electric generation assets and supply contracts that serve wholesale and industrial customers, in addition to various merchant plants currently in development. PG&E NEG manages such risks using a cost-effective risk management program that primarily includes the buying and selling of fixed-price commodity commitments to lock in future cash flows of their forecasted generation. PG&E NEG is also exposed to commodity price risk of net open positions within their trading portfolio due to the assessment of and response to changing market conditions.

Value-at-Risk

PG&E Corporation and the Utility measure commodity price risk exposure using value-at-risk and other methodologies that simulate future price movements in the energy markets to estimate the size and probability of future potential losses. Market risk is quantified using a variance/co-variance value-at-risk model that provides a consistent measure of risk across diverse energy markets and products. The use of this methodology requires a number of important assumptions, including the selection of a confidence level for losses, volatility of prices, market liquidity, and a holding period.

PG&E Corporation uses historical data for calculating the price volatility of its contractual positions and how likely the prices of those positions will move together. The model includes all derivatives and commodity instruments in the trading and non-trading portfolios. PG&E Corporation and the Utility express value-at-risk as a dollar amount of the potential loss in the fair value of their portfolios based on a 95 percent confidence level using a one-day liquidation period. Therefore, there is a 5 percent probability that PG&E Corporation and its subsidiaries' portfolios will incur a loss in one day greater than its value-at-risk. For example, if the value-at-risk is calculated at $5 million, there is a 95 percent confidence level that if prices moved against current positions, the reduction in the value of the portfolio resulting from such one-day price movements would not exceed $5 million.

The following table illustrates the daily value-at-risk exposure for commodity price risk.

(in millions)	December 31, 2001	December 31, 2000	Year Ended December 31, 2001 Average	High	Low
Utility					
Non-trading*	$ 3.6	$187.4	$21.9	$69.3	$3.3
PG&E NEG					
Trading	5.8	11.5	10.2	15.3	5.8
Non-Trading**	10.3	8.8	11.3	19.0	7.4
Portfolio***	65.2	—	—	—	—

* Includes the Utility's gas portfolio only. The Utility believes that there is currently no commodity price risk associated with fluctuating electric power prices, because the Utility is not currently responsible for managing the net open position.

** Includes only the risk related to the financial instruments that serve as hedges and does not include the related underlying hedged item.

*** Portfolio VAR includes a rolling three year position reflecting the underlying position associated with PG&E NEG's owned assets, the full tenor of PG&E NEG's asset hedges, and trading positions.

Value-at-risk 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, inadequate indication of the exposure of a portfolio to extreme price movements, and the inability to address the risk resulting from intra-day trading activities. Value-at-risk also does not reflect the significant regulatory, legislative, and legal risks currently facing the Utility due to the Utility's bankruptcy proceedings and the current California energy crisis.

Interest Rate Risk

Interest rate risk is the risk that changes in interest rates could adversely affect earnings and cash flows. Specific interest rate risks for PG&E Corporation and the Utility include the risk of increasing interest rates on short-term and long-term floating rate debt, the risk of decreasing rates on floating rate assets which have been financed with fixed rate debt, the risk of increasing interest rates for planned new fixed long-term financings, and the risk of increasing interest rates for planned refinancing using long-term fixed rate debt. In addition, the Utility is exposed to changes in interest rates on interest accruing on loan payments and trade payables currently in default.

PG&E Corporation uses the following interest rate instruments to manage its interest rate exposure: interest rate swaps, interest rate caps, floors, or collars, swaptions, or interest rate forward and futures contracts. Interest rate risk sensitivity analysis is used to measure interest rate price risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. If interest rates change by 1 percent for all variable rate debt at PG&E Corporation and the Utility, the change would affect net income by approximately $32.5 million and $26.4 million, respectively, based on variable rate debt and derivatives and other interest rate sensitive instruments outstanding at December 31, 2001.

Foreign Currency Risk

Foreign currency risk is the risk of changes in value of pending financial obligations in foreign currencies that could occur prior to the settlement of the obligation due to a change in the value of that foreign currency in relation to the U.S. dollar. The Utility and PG&E Corporation are exposed to foreign currency risk associated with foreign currency exchange variations related to Canadian-denominated purchase and swap agreements. In addition, PG&E Corporation has translation exposure resulting from the need to translate Canadian-denominated financial statements of its affiliate PG&E Energy Trading Canada Corporation into U.S. dollars for PG&E NEG Consolidated Financial Statements. PG&E Corporation and the Utility use forwards, swaps, and options to hedge foreign currency exposure.

PG&E Corporation and the Utility use sensitivity analysis to measure their foreign currency exchange rate exposure to the Canadian dollar. Based on a sensitivity analysis at December 31, 2001, a 10 percent devaluation of the Canadian dollar would be immaterial to PG&E Corporation's and the Utility's Consolidated Financial Statements.

Credit Risk

Credit risk is the risk of loss that PG&E Corporation and the Utility would incur if counterparties fail to perform their contractual obligations. PG&E Corporation and the Utility primarily conduct business with customers in the energy industry, and this concentration of counterparties may impact the overall exposure to credit risk in that its counterparties may be similarly affected by changes in economic, regulatory, or other conditions. PG&E Corporation and the Utility manage credit risk pursuant to its Risk Management Policies, which provide processes by which counterparties are assigned credit limits in advance of entering into significant exposure. These procedures include an evaluation of a potential counterparty's financial condition, net worth, credit rating, and other credit criteria as deemed appropriate and are performed at least annually. Credit exposure is calculated daily and, in the event that exposure exceeds the established limits, PG&E Corporation and the Utility take immediate action to reduce exposure and/or obtain additional collateral. Further, PG&E Corporation and the Utility rely heavily on master agreements that allow for the netting of positive and negative exposures associated with a counterparty. No single counterparty represents greater than 10 percent of PG&E Corporation's total gross credit exposure at December 31, 2001. The fair value of all claims against these counterparties that are in a net asset position, with the exception of exchange-traded futures (the exchange guarantees that every contract is properly settled on a daily basis), as of December 31, 2001, amount to the following:

(in millions)	Gross Exposure*	Credit Collateral**	Net Exposure**
PG&E NEG	$ 932	$ 80	$852
Utility	271	127	144
PG&E Corporation	$1,203	$207	$996

* Gross credit exposure equals mark-to-market value plus net (payables) receivables where netting is allowed. The Utility's gross exposure includes wholesale activity only. Retail activity and payables prior to the Utility's bankruptcy filing are not included.

** Net exposure is the gross exposure minus credit collateral (cash deposits and letters of credit). Amounts are not adjusted for probability of default.

The majority of counterparties to which PG&E Corporation and the Utility are exposed are considered to be of investment grade, determined using publicly available information including an S&P's rating of at least BBB-. $296 million or 25 percent of PG&E Corporation's gross credit exposure and $59 million or 22 percent of the Utility's gross credit exposure is below investment grade. PG&E Corporation has regional concentrations of credit exposure to counterparties that primarily conduct business throughout the western United States (30 percent) and also to counterparties that primarily conduct business throughout the entire United States (51 percent). The Utility has a regional concentration of credit exposure to counterparties that primarily conduct business throughout the entire United States (93 percent).

Related Party Agreements

In accordance with various agreements, the Utility and other subsidiaries provide and receive various services from their parent, PG&E Corporation. The Utility and PG&E Corporation exchange administrative and professional support services in support of operations. These services are priced at either the fully loaded cost or at the higher of fully loaded cost or fair market value depending on the nature of the services provided. PG&E Corporation also allocates certain other corporate administrative and general costs to the Utility and other subsidiaries using a variety of factors, including their share of employees, operating expenses, assets, and other cost causal methods. Additionally, the Utility purchases gas commodity and transmission services from, and sells reservation and other ancillary services to, PG&E NEG. These services are priced at either tariff rates or fair market value depending on the nature of the services provided. Intercompany transactions are eliminated in consolidation and no profit results from these transactions.

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

(in millions)	Year ended December 31, 2001	2000	1999
Utility revenues from:			
Administrative services provided to PG&E Corporation	$ 6	$ 12	$ 23
Transportation and distribution services provided to PG&E ES	—	—	134
Gas reservation services provided to PG&E ET	11	12	7
Other	1	2	3
	$ 18	$ 26	$167
Utility expenses from:			
Administrative services received from PG&E Corporation	$127	$ 83	$ 66
Gas commodity and transmission services received from PG&E ET	120	136	30
Transmission services received from PG&E GT	41	46	47
	$288	$265	$143

Additional Security Measures

In response to the September 11, 2001, terrorist attacks, PG&E Corporation and the Utility increased security measures at critical facilities. PG&E Corporation and the Utility continue to maintain a heightened state of alert at all facilities as well as close coordination with federal, state, and local law enforcement agencies.

Critical Accounting Policies

PG&E Corporation and the Utility apply SFAS No. 71 to their regulated operations. This standard allows a cost to be capitalized, that otherwise would be charged to expense if it is probable that the cost is recoverable through regulated rates. This standard also allows a regulator to create a liability that is recognized in the financial statements. PG&E Corporation and the Utility's regulatory assets and liabilities are discussed further in Note 1 in the Notes to the Consolidated Financial Statements.

The Utility also used the guidance included in SFAS No. 121 "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of," when in 2000 it concluded that $6.9 billion of regulatory assets was not probable of recovery and wrote off its generation-related regulatory assets and under-collected purchased power costs. See Note 3 of the Notes to the Consolidated Financial Statements for further discussion. PG&E NEG also applied SFAS No. 121 when it wrote down its investment in PG&E GTT and the PG&E Energy Services business unit.

The Utility's 2001 financial statements are presented in accordance with SOP 90-7, which is used for entities in reorganization under the bankruptcy code.

Effective 2001, PG&E Corporation and the Utility adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138, "Accounting for Certain Derivative Instruments and Hedging Activities" (collectively, SFAS No. 133), which required all financial instruments to be recognized in the financial statements at market value. See further discussion in "Quantitative and Qualitative Disclosure about Market Risk" above, and Notes 4 and 5 of the Notes to the Consolidated Financial Statements. PG&E NEG accounts for its energy trading activities in accordance with EITF 98-10 and SFAS No. 133, which require certain energy trading contracts to be accounted for at fair values using mark-to-market accounting. EITF 98-10 also allows two methods of recognizing energy trading contracts in the income statement. The "gross" method provides that the contracts are recorded at their full value in revenues and expenses. The other method is the "net" method in which revenues and expenses are netted and only the trading margin (or when realized sometimes trading loss) is reflected in revenues. PG&E NEG used the gross method for those energy trading contracts for which they have a choice.

PG&E Corporation commodities and service revenues derived from power generation are recognized upon output, product delivery or satisfaction of specific targets. Regulated gas and electric revenues are recorded as services are provided based upon applicable tariffs and include amounts for services rendered but not yet billed.

New Accounting Standards

Effective January 1, 2001, PG&E Corporation and the Utility adopted SFAS No. 133, as amended. SFAS No. 133 requires PG&E Corporation and the Utility to recognize all derivatives, as defined on the balance sheet at fair value. PG&E Corporation's transition adjustment to implement this new SFAS No. 133 on January 1, 2001, resulted in a non-material decrease to earnings and an after-tax decrease of $243 million to accumulated other comprehensive income. The Utility's transition adjustment to implement SFAS No. 133 resulted in a non-material decrease to earnings and an after-tax $90 million positive adjustment to accumulated other comprehensive loss. These transition adjustments, which relate to hedges of interest rate, foreign currency, and commodity price risk exposure, were recognized as of January 1, 2001, as a cumulative effect of a change in accounting principle.

Derivatives are classified as price risk management assets and price risk management liabilities on the balance sheet. Derivatives, or any portion thereof, that are not effective hedges are adjusted to fair value through income. For derivatives that are effective hedges, depending on the nature of the hedge, changes in the fair value are either offset by changes in the fair value of the hedged assets or liabilities through earnings or recognized in accumulated other comprehensive income (loss) until the hedged item is recognized in earnings. Net gains or losses on derivative instruments recognized for the year ended December 31, 2001, were included in various lines on the Consolidated Statements of Operations, including energy commodities and services revenue, cost of energy commodities and services, interest income or interest expense, and other income (expense), net.

PG&E Corporation also has derivative commodity contracts for the physical delivery of purchase and sale quantities transacted in the normal course of business. These derivatives are exempt from the requirements of SFAS No. 133 under the normal purchase and sales exception, and are not reflected on the balance sheet at fair value. In June 2001 (as amended in October 2001 and December 2001), the Financial Accounting Standards Board (FASB) approved an interpretation issued by the Derivatives Implementation Group (DIG) that changed the definition of normal purchases and sales for certain power contracts. PG&E Corporation must implement this interpretation on April 1, 2002, and is currently assessing the impact of these new rules. PG&E Corporation anticipates that implementation of this interpretation will result in several contracts failing to continue qualifying for the normal purchases and sales exemption, possibly resulting in these contracts being marked-to-market through earnings. The FASB has also approved another DIG interpretation that disallows normal purchases and sales treatment for commodity contracts (other than power contracts) that contain volumetric variability or optionality. Certain of PG&E Corporation's derivative commodity contracts may no longer be exempt from the requirements of the Statement. PG&E Corporation is evaluating the impact of this implementation guidance on its financial statements, and will implement this guidance, as appropriate, by the implementation deadline of April 1, 2002.

To qualify for the normal purchases and sales exception from SFAS No. 133, a contract must have pricing that is deemed to be clearly and closely related to the asset to be delivered under the contract. In 2001, the FASB approved another interpretation issued by the DIG that clarifies how this requirement applies to certain commodity contracts. In applying this new DIG guidance, PG&E Corporation determined that one of its derivative commodity contracts no longer qualifies for normal purchases and sales treatment, and must be marked-to-market through earnings. The cumulative effect of this change in accounting principle increased earnings by approximately $9 million (after-tax).

In June 2001, the FASB issued SFAS No. 141, "Business Combinations." This Statement, which applies to all business combinations accounted for under the purchase method completed after June 30, 2001, prohibits the use of pooling-of-interests method of accounting for business combinations and provides a new definition of intangible assets. This standard will be applied to any prospective acquisitions.

Also in June 2001, the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets." This Statement eliminates the amortization of goodwill, and requires that goodwill be reviewed at least annually for impairment. This Statement also requires that the useful lives of previously recognized intangible assets be reassessed and the remaining amortization periods be adjusted accordingly. This Statement is effective for fiscal years beginning after December 15, 2001, and affects all goodwill and other intangible assets recognized on a company's statement of financial position at that date, regardless of when the assets were initially recognized. This statement was adopted on January 1, 2002, and did not have a significant impact on the financial statements of PG&E Corporation and the Utility.

In August 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." This Statement is effective for fiscal years beginning after June 15, 2002. SFAS No. 143 provides accounting requirements for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. Under the Statement, the asset retirement obligation is recorded at fair value in the period in which it is incurred by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value in each subsequent period and the capitalized cost is depreciated over the useful life of the related asset. PG&E Corporation and the Utility are currently evaluating the impact of SFAS No. 143, but have not yet determined the effects of this Statement on their financial statements.

In October 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," which addresses financial accounting and reporting for the impairment or disposal of long-lived assets. SFAS No. 144 supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of," but retains the fundamental provisions for recognizing and measuring impairment of long-lived assets to be held and used or disposed of by sale. The Statement also supersedes the accounting and reporting provisions for the disposal of a segment of a business, and eliminates the exception to consolidation for a subsidiary for which control is likely to be temporary. SFAS No. 144 eliminates the conflict between accounting models for treating the disposition of long-lived assets that existed between SFAS No. 121 and the guidance for a segment of a business accounted for as a discontinued operation by adopting the methodology established in SFAS No. 121, and also resolves implementation issues related to SFAS No. 121. This Statement is effective for fiscal years beginning after December 15, 2001. PG&E Corporation and the Utility adopted this statement on January 1, 2002, and the adoption did not have any immediate impact on the financial statements of PG&E Corporation or the Utility.

Legal Matters

In the normal course of business, both PG&E Corporation and the Utility are named as parties in a number of claims and lawsuits. See Note 16 of the Notes to the Consolidated Financial Statements for further discussion of significant pending legal matters.

PG&E Corporation

CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions, except per share amounts)

	Year ended December 31, 2001	2000	1999
Operating Revenues			
Utility	$10,462	$ 9,637	$9,228
Energy commodities and services	12,497	16,583	11,591
Total operating revenues	22,959	26,220	20,819
Operating Expenses			
Cost of energy for utility	4,606	8,166	3,149
Deferred electric procurement cost	—	(6,465)	—
Cost of energy commodities and services	11,339	15,220	10,587
Operating and maintenance	3,113	3,508	3,150
Depreciation, amortization, and decommissioning	1,068	3,659	1,780
Loss on assets held for sale	—	—	1,275
Provision for loss on generation-related regulatory assets and under-collected purchased power costs	—	6,939	—
Reorganization professional fees and expenses	97	—	—
Total operating expenses	20,223	31,027	19,941
Operating Income (Loss)	2,736	(4,807)	878
Reorganization interest income	91	—	—
Interest income	122	266	118
Interest expense	(1,213)	(788)	(772)
Other income (expense), net	(38)	(23)	37
Income (Loss) Before Income Taxes	1,698	(5,352)	261
Income taxes provision (benefit)	608	(2,028)	248
Income (Loss) from Continuing Operations	1,090	(3,324)	13
Discontinued Operations			
Loss from operations of PG&E Energy Services (net of applicable income taxes of $35 million)	—	—	(40)
Loss on disposal of PG&E Energy Services (net of applicable income taxes of $36 million, and $36 million, respectively)	—	(40)	(58)
Net Income (Loss) Before Cumulative Effect of a Change in Accounting Principle	1,090	(3,364)	(85)
Cumulative effect of a change in an accounting principle (net of applicable income taxes of $6 million, and $8 million, respectively)	9	—	12
Net Income (Loss)	$ 1,099	$(3,364)	$ (73)
Weighted Average Common Shares Outstanding	363	362	368
Income (Loss) Per Common Share, from Continuing Operations, Basic	$ 3.00	$ (9.18)	$ 0.04
Net Earnings (Loss) Per Common Share, Basic	$ 3.03	$ (9.29)	$(0.20)
Income (Loss) Per Common Share, from Continuing Operations, Diluted	$ 2.99	$ (9.18)	$ 0.04
Net Earnings (Loss) Per Common Share, Diluted	$ 3.02	$ (9.29)	$(0.20)
Dividends Declared Per Common Share	$ —	$ 1.20	$ 1.20

The accompanying Notes to the Consolidated Financial Statements are an integral part of this statement.

PG&E Corporation

CONSOLIDATED BALANCE SHEETS
(in millions)

	Balance at December 31, 2001	Balance at December 31, 2000
ASSETS		
Current Assets		
Cash and cash equivalents	$ 5,421	$ 2,430
Restricted cash	195	129
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $89 million and $71 million, respectively)	3,016	4,340
Regulatory balancing accounts	75	222
Price risk management	381	2,039
Inventories	462	392
Income taxes receivable	—	1,241
Prepaid expenses and other	223	406
Total current assets	9,773	11,199
Property, Plant and Equipment		
Utility	26,029	25,011
Non-utility:		
Electric generation	2,848	2,008
Gas transmission	1,514	1,542
Construction work in progress	2,426	1,605
Other	195	147
Total property, plant and equipment (at original cost)	33,012	30,313
Accumulated depreciation and decommissioning	(13,845)	(13,017)
Net property, plant and equipment	19,167	17,296
Other Noncurrent Assets		
Regulatory assets	2,319	1,773
Nuclear decommissioning funds	1,337	1,328
Price risk management	426	2,026
Other	2,840	2,530
Total other noncurrent assets	6,922	7,657
TOTAL ASSETS	$ 35,862	$ 36,152

PG&E Corporation

CONSOLIDATED BALANCE SHEETS
(in millions, except share amounts)

	Balance at December 31, 2001	Balance at December 31, 2000
LIABILITIES AND EQUITY		
Liabilities Not Subject to Compromise		
Current Liabilities		
Short-term borrowings	$ 330	$ 4,530
Long-term debt, classified as current	381	2,391
Current portion of rate reduction bonds	290	290
Accounts payable:		
Trade creditors	1,289	5,896
Regulatory balancing accounts	228	196
Other	530	459
Price risk management	277	1,999
Other	1,541	1,570
Total current liabilities	4,866	17,331
Noncurrent Liabilities		
Long-term debt	7,297	5,550
Rate reduction bonds	1,450	1,740
Deferred income taxes	1,666	1,656
Deferred tax credits	153	192
Price risk management	434	1,867
Other	3,688	3,864
Total noncurrent liabilities	14,688	14,869
Liabilities Subject to Compromise		
Financing debt	5,651	—
Trade creditors	5,555	—
Total liabilities subject to compromise	11,206	—
Preferred Stock of Subsidiaries	480	480
Utility Obligated Mandatorily Redeemable Preferred Securities of Trust Holding Solely Utility Subordinated Debentures	300	300
Common Stockholders' Equity		
Common stock, no par value, authorized 800,000,000 shares, issued 387,898,848 and 387,193,727 shares, respectively	5,986	5,971
Common stock held by subsidiary, at cost, 23,815,500 shares	(690)	(690)
Accumulated deficit	(1,004)	(2,105)
Accumulated other comprehensive income (loss)	30	(4)
Total common stockholders' equity	4,322	3,172
Commitments and Contingencies (Notes 1, 2, 3, 15, and 16)	—	—
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$35,862	$36,152

The accompanying Notes to the Consolidated Financial Statements are an integral part of this statement.

PG&E Corporation

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year ended December 31,		
	2001	2000	1999
Cash Flows from Operating Activities			
Net income (loss)	$ 1,099	$(3,364)	$ (73)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	1,068	3,659	1,780
Deferred electric procurement costs	—	(6,465)	—
Deferred income taxes and tax credits, net	(409)	(767)	(754)
Price risk management assets and liabilities, net	137	30	(28)
Other deferred charges and noncurrent liabilities	(693)	256	102
Provision for loss on generation-related regulatory assets and under-collected purchased power costs	—	6,939	—
Loss on assets held for sale	—	—	1,275
Loss from discontinued operations	—	40	98
Cumulative effect of change in accounting principle	(9)	—	(12)
Net effect of changes in operating assets and liabilities:			
Accounts receivable	1,324	(2,322)	370
Inventories	(70)	41	23
Accounts payable	1,018	4,594	(279)
Accrued taxes	1,241	(1,452)	108
Regulatory balancing accounts, net	179	(410)	305
Other working capital	155	324	209
Other, net	260	(398)	(822)
Net cash provided by operating activities	5,300	705	2,302
Cash Flows from Investing Activities			
Capital expenditures	(2,665)	(2,346)	(1,701)
Net proceeds from sales of businesses	—	415	1,014
Other, net	(235)	241	453
Net cash used by investing activities	(2,900)	(1,690)	(234)
Cash Flows from Financing Activities			
Net borrowings (repayments) under credit facilities	(1,148)	2,846	(145)
Long-term debt issued	2,993	1,734	103
Long-term debt matured, redeemed, or repurchased	(1,158)	(1,155)	(798)
Common stock issued	15	65	54
Common stock repurchased	(1)	(2)	(693)
Dividends paid	(109)	(436)	(465)
Other, net	(1)	23	4
Net cash provided (used) by financing activities	591	3,075	(1,940)
Net change in cash and cash equivalents	2,991	2,090	128
Cash and cash equivalents at January 1	2,430	340	212
Cash and cash equivalents at December 31	$ 5,421	$ 2,430	$ 340
Supplemental disclosures of cash flow information			
Cash paid for:			
Interest (net of amounts capitalized)	$ 579	$ 748	$ 729
Income taxes paid (refunded), net	(692)	20	723
Supplemental disclosures of noncash investing and financing activities			
Retirement of long-term debt on the sale of PG&E Gas Transmission, Texas	—	564	—
Transfer of liabilities and other payables subject to compromise from operating assets and liabilities	11,206	—	—

The accompanying Notes to the Consolidated Financial Statements are an integral part of this statement.

PG&E Corporation

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

(in millions, except share amounts)

	Common Stock	Common Stock Held by Subsidiary	Reinvested Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Total Common Stockholders' Equity	Comprehensive Income (Loss)
Balance at December 31, 1998	$5,862	$ —	$ 2,210	$ (6)	$8,066	
Net loss	—	—	(73)	—	(73)	$ (73)
Foreign currency translation adjustment	—	—	—	2	2	2
Comprehensive loss						$ (71)
Common stock issued (1,879,474 shares)	54	—	—	—	54	
Common stock repurchased (23,892,425 shares)	(2)	(690)	(1)	—	(693)	
Cash dividends declared on common stock	—	—	(460)	—	(460)	
Other	(8)	—	(2)	—	(10)	
Balance at December 31, 1999	5,906	(690)	1,674	(4)	6,886	
Net loss	—	—	(3,364)	—	(3,364)	$(3,364)
Common stock issued (2,847,269 shares)	65	—	—	—	65	
Common stock repurchased (59,655 shares)	(1)	—	(1)	—	(2)	
Cash dividends declared on common stock	—	—	(434)	—	(434)	
Other	1	—	20	—	21	
Balance at December 31, 2000	5,971	(690)	(2,105)	(4)	3,172	
Net income	—	—	1,099	—	1,099	$ 1,099
Cumulative effect of adoption of SFAS No. 133	—	—	—	(243)	(243)	(243)
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133	—	—	—	237	237	237
Net reclassification to earnings	—	—	—	42	42	42
Foreign currency translation adjustment	—	—	—	(1)	(1)	(1)
Other	—	—	—	(1)	(1)	(1)
Comprehensive income						$ 1,133
Common stock issued (739,158 shares)	16	—	—	—	16	
Common stock repurchased (34,037 shares)	(1)	—	—	—	(1)	
Other	—	—	2	—	2	
Balance at December 31, 2001	$5,986	$(690)	$(1,004)	$ 30	$4,322	

The accompanying Notes to the Consolidated Financial Statements are an integral part of this statement.

Pacific Gas and Electric Company, a Debtor-In-Possession

CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions)

	Year ended December 31,		
	2001	2000	1999
Operating Revenues			
Electric	$ 7,326	$ 6,854	$7,232
Gas	3,136	2,783	1,996
Total operating revenues	10,462	9,637	9,228
Operating Expenses			
Cost of electric energy	2,774	6,741	2,411
Deferred electric procurement cost	—	(6,465)	—
Cost of gas	1,832	1,425	738
Operating and maintenance	2,385	2,687	2,522
Depreciation, amortization, and decommissioning	896	3,511	1,564
Provision for loss on generation-related regulatory assets and under-collected purchased power costs	—	6,939	—
Reorganization professional fees and expenses	97	—	—
Total operating expenses	7,984	14,838	7,235
Operating Income (Loss)	2,478	(5,201)	1,993
Reorganization interest income	91	—	—
Interest income	32	186	45
Interest expense (contractual interest of $810 million for 2001)	(974)	(619)	(593)
Other income (expense), net	(16)	(3)	(9)
Income (Loss) Before Income Taxes	1,611	(5,637)	1,436
Income tax provision (benefit)	596	(2,154)	648
Net Income (Loss)	1,015	(3,483)	788
Preferred dividend requirement	25	25	25
Income (Loss) Available for (Allocated to) Common Stock	$ 990	$(3,508)	$ 763

The accompanying Notes to the Consolidated Financial Statements are an integral part of this statement.

Pacific Gas and Electric Company, a Debtor-In-Possession

CONSOLIDATED BALANCE SHEETS
(in millions)

	Balance at December 31, 2001	Balance at December 31, 2000
ASSETS		
Current Assets		
Cash and cash equivalents	$ 4,341	$ 1,344
Restricted cash	53	50
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $48 million and $52 million, respectively)	1,931	1,711
Related parties	18	6
Regulatory balancing accounts	75	222
Inventories:		
Gas stored underground and fuel oil	218	146
Materials and supplies	119	134
Income taxes receivable	—	1,120
Prepaid expenses and other	80	45
Total current assets	6,835	4,778
Property, Plant and Equipment		
Electric	18,219	17,474
Gas	7,810	7,537
Construction work in progress	323	249
Total property, plant and equipment (at original cost)	26,352	25,260
Accumulated depreciation and decommissioning	(12,943)	(12,259)
Net property, plant and equipment	13,409	13,001
Other Noncurrent Assets		
Regulatory assets	2,283	1,716
Nuclear decommissioning funds	1,337	1,328
Other	1,273	1,165
Total other noncurrent assets	4,893	4,209
TOTAL ASSETS	$ 25,137	$ 21,988

Pacific Gas and Electric Company, a Debtor-In-Possession

CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)

	Balance at December 31, 2001	Balance at December 31, 2000
LIABILITIES AND EQUITY		
Liabilities Not Subject to Compromise		
Current Liabilities		
Short-term borrowings	$ —	$ 3,079
Long-term debt, classified as current	333	2,374
Current portion of rate reduction bonds	290	290
Accounts payable:		
Trade creditors	333	3,688
Related parties	86	138
Regulatory balancing accounts	228	196
Other	289	363
Income taxes payable	295	—
Deferred income taxes	65	172
Other	625	670
Total current liabilities	2,544	10,970
Noncurrent Liabilities		
Long-term debt	3,019	3,342
Rate reduction bonds	1,450	1,740
Deferred income taxes	1,028	929
Deferred tax credits	153	192
Other	2,724	2,968
Total noncurrent liabilities	8,374	9,171
Liabilities Subject to Compromise		
Financing debt	5,651	—
Trade creditors	5,733	—
Total liabilities subject to compromise	11,384	—
Preferred Stock With Mandatory Redemption Provisions		
6.30% and 6.57%, outstanding 5,500,000 shares, due 2002-2009	137	137
Company Obligated Mandatorily Redeemable Preferred Securities of Trust Holding Solely Utility Subordinated Debentures		
7.90%, 12,000,000 shares, due 2025	300	300
Stockholders' Equity		
Preferred stock without mandatory redemption provisions		
Nonredeemable, 5.00% to 6.00%, outstanding 5,784,825 shares	145	145
Redeemable, 4.36% to 7.04%, outstanding 5,973,456 shares	149	149
Common stock, $5 par value, authorized 800,000,000 shares, issued 326,926,667 shares	1,606	1,606
Common stock held by subsidiary, at cost, 19,481,213 shares	(475)	(475)
Additional paid-in capital	1,964	1,964
Accumulated deficit	(989)	(1,979)
Accumulated other comprehensive loss	(2)	—
Total stockholders' equity	2,398	1,410
Commitments and Contingencies (Notes 1, 2, 3, 15, and 16)	—	—
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$25,137	$21,988

The accompanying Notes to the Consolidated Financial Statements are an integral part of this statement.

Pacific Gas and Electric Company, a Debtor-In-Possession

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year ended December 31, 2001	2000	1999
Cash Flows from Operating Activities			
Net income (loss)	$ 1,015	$(3,483)	$ 788
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Deferred electric procurement costs	—	(6,465)	—
Depreciation, amortization, and decommissioning	896	3,511	1,564
Deferred income taxes and tax credits, net	(306)	(930)	(485)
Other deferred charges and noncurrent liabilities	(902)	480	101
Provision for loss on generation-related regulatory assets and under-collected purchased power costs	—	6,939	—
Net effect of changes in operating assets and liabilities:			
Accounts receivable	237	(507)	187
Income tax receivable	1,120	(1,120)	—
Inventories	(57)	14	18
Accounts payable	1,312	3,063	15
Accrued taxes	295	(118)	116
Regulatory balancing accounts, net	179	(410)	305
Other working capital	692	103	(77)
Other, net	284	(522)	(352)
Net cash provided by operating activities	4,765	555	2,180
Cash Flows from Investing Activities			
Capital expenditures	(1,343)	(1,245)	(1,181)
Proceeds from sale of assets	—	6	1,014
Other, net	5	32	234
Net cash provided (used) by investing activities	(1,338)	(1,207)	67
Cash Flows from Financing Activities			
Net (repayments) borrowings under credit facilities and short-term borrowings	(28)	2,630	(219)
Long-term debt issued	—	680	—
Long-term debt matured, redeemed, or repurchased	(401)	(597)	(672)
Common stock repurchased	—	(275)	(926)
Dividends paid	—	(475)	(440)
Other, net	(1)	(26)	1
Net cash provided (used) by financing activities	(430)	1,937	(2,256)
Net change in cash and cash equivalents	2,997	1,285	(9)
Cash and cash equivalents at January 1	1,344	59	68
Cash and cash equivalents at December 31	$ 4,341	$ 1,344	$ 59
Supplemental disclosures of cash flow information			
Cash received for:			
Reorganization interest income	$ 87	$ —	$ —
Cash paid for:			
Interest (net of amounts capitalized)	361	587	531
Income taxes paid (refunded), net	(556)	—	1,001
Reorganization professional fees and expenses	19	—	—
Supplemental disclosures of noncash investing and financing activities			
Transfer of liabilities and other payables subject to compromise from operating assets and liabilities	11,384	—	—

The accompanying Notes to the Consolidated Financial Statements are an integral part of this statement.

Pacific Gas and Electric Company, a Debtor-In-Possession

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(in millions, except share amounts)

	Common Stock	Additional Paid-in Capital	Common Stock Held by Subsidiary	Reinvested Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Total Common Stockholder's Equity	Preferred Stock Without Mandatory Redemption Provisions	Comprehensive Income (Loss)
Balance at December 31, 1998	$1,707	$2,087	$ —	$ 2,261	$ (1)	$ 6,054	$294	
Net income	—	—	—	788	—	788	—	$ 788
Foreign currency translation adjustments	—	—	—	—	1	1	—	1
Comprehensive income								$ 789
Common stock repurchased (27,666,460 shares)	(101)	(123)	(200)	(502)	—	(926)	—	
Cash dividends declared								
Preferred stock	—	—	—	(25)	—	(25)	—	
Common stock	—	—	—	(415)	—	(415)	—	
Balance at December 31, 1999	1,606	1,964	(200)	2,107	—	5,477	294	
Net loss	—	—	—	(3,483)	—	(3,483)	—	$(3,483)
Common stock repurchased (11,853,448 shares)	—	—	(275)	—	—	(275)	—	
Cash dividends declared								
Preferred stock	—	—	—	(25)	—	(25)	—	
Common stock	—	—	—	(578)	—	(578)	—	
Balance at December 31, 2000	1,606	1,964	(475)	(1,979)	—	1,116	294	
Net Income	—	—	—	1,015	—	1,015	—	$ 1,015
Cumulative effect of adoption of SFAS No. 133	—	—	—	—	90	90	—	90
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133	—	—	—	—	(5)	(5)	—	(5)
Net reclassification to earnings	—	—	—	—	(85)	(85)	—	(85)
Foreign currency translation adjustments	—	—	—	—	(2)	(2)	—	(2)
Comprehensive income								$ 1,013
Preferred stock dividend requirement	—	—	—	(25)	—	(25)	—	
Balance at December 31, 2001	$1,606	$1,964	$(475)	$ (989)	$ (2)	$ 2,104	$294	

The accompanying Notes to the Consolidated Financial Statements are an integral part of this statement.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1: General

Basis of Presentation

PG&E Corporation was incorporated in California in 1995 and became the holding company of Pacific Gas and Electric Company, a debtor-in-possession (the Utility), and its subsidiaries on January 1, 1997. The Utility, incorporated in California in 1905, is the predecessor of PG&E Corporation. As discussed further in Notes 2 and 3, on April 6, 2001, the Utility filed a voluntary petition for relief under the provisions of Chapter 11 of the United States Bankruptcy Code (Bankruptcy Code) in the United States Bankruptcy Court for the Northern District of California (Bankruptcy Court). Pursuant to Chapter 11, the Utility retains control of its assets and is authorized to operate its business as a debtor-in-possession while being subject to the jurisdiction of the Bankruptcy Court. On September 20, 2001, the Utility and PG&E Corporation jointly filed with the Bankruptcy Court a proposed plan of reorganization of the Utility (Plan) and the proposed disclosure statement describing the proposed plan.

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 PG&E Corporation's wholly owned and controlled subsidiaries. The Utility's consolidated financial statements include its accounts as well as those of its wholly owned and controlled subsidiaries. All significant inter-company 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 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. Actual results could differ from these estimates.

Accounting principles used include those necessary for rate-regulated enterprises, which reflect the ratemaking policies of the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC).

Operations

PG&E Corporation is an energy-based holding company headquartered in San Francisco, California. The Utility provides electric service to approximately 4.8 million customers and natural gas service to approximately 3.9 million customers in Northern and Central California. PG&E Corporation's PG&E National Energy Group, Inc. (PG&E NEG) markets energy services and products throughout North America.

PG&E NEG is an integrated energy company with a strategic focus on power generation, natural gas transmission and wholesale energy marketing and trading in North America. PG&E NEG and its subsidiaries have integrated their generation, development, and energy marketing and trading activities in an effort to create energy products in response to customer needs, increase the returns from its operations and identify and capitalize on opportunities to optimize generating and pipeline capacity. PG&E NEG was incorporated on December 18, 1998, as a wholly owned subsidiary of PG&E Corporation. Shortly thereafter, PG&E Corporation contributed various subsidiaries to PG&E NEG. The principal subsidiaries of PG&E NEG include: PG&E Generating Company, LLC and its subsidiaries (collectively, PG&E Gen LLC); PG&E Energy Trading Holdings Corporation and its subsidiaries (collectively, PG&E Energy Trading or PG&E ET); PG&E Gas Transmission Corporation and its subsidiaries (collectively, PG&E GTC), which includes PG&E Gas Transmission, Northwest Corporation and its subsidiaries (collectively, PG&E GTN), PG&E North Baja Pipeline, LLC (PG&E NBP), and PG&E Gas Transmission, Texas Corporation and its subsidiaries, and PG&E Gas Transmission Teco, Inc. and its subsidiaries (collectively, PG&E GTT) (see Note 6 for a discussion of the sale of PG&E GTT). PG&E Energy Services Corporation (PG&E ES), which was discontinued in 1999, provided retail energy services. PG&E NEG also has other less significant subsidiaries.

Cash and Cash Equivalents

Cash and cash equivalents include cash and working funds with original maturities of three months or less when purchased. Cash equivalents are stated at cost, which approximates fair value. PG&E Corporation's and the Utility's cash equivalents are held in a variety of funds that primarily invest in certificates of deposit, time deposits, bankers' acceptances, and other short-term securities issued by banks, asset-backed securities, repurchase agreements, high-grade commercial paper, and discounted notes issued or guaranteed by the United States government or its agencies. In general, the securities are purchased on the date of issue and held in the accounts until maturity. Substantially all of PG&E Corporation's and the Utility's cash equivalents on hand at December 31, 2001, have matured and been reinvested. At December 31, 2001, three funds held balances greater than 10 percent of PG&E Corporation's and the Utility's cash and cash equivalents balance. They were: the Citifunds Institutional Liquid Reserves Fund, the Dreyfus Cash Management Plus Fund, and the Fiduciary Trust Company International.

Restricted Cash

Restricted cash includes cash and cash equivalents, as defined above, which are restricted under the terms of certain agreements for payment to third parties, primarily for debt service.

Inventories

Inventories include materials and supplies, gas stored underground, coal, and fuel oil. Materials and supplies, and gas stored underground are valued at average cost, except for the gas storage inventory of PG&E ET, which is recorded at fair value. Coal and fuel oil are valued by the last-in first-out method.

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, primarily 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 percent or more. In addition, PG&E Corporation files combined state income tax returns when 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.

Earnings (Loss) Per Share

Basic earnings (loss) per share is computed by dividing net income (loss) by the weighted average number of common shares outstanding during the period. Diluted earnings per share is computed by dividing net income by the weighted average number of common shares outstanding plus the assumed issuance of common shares for all dilutive securities.

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

(in millions, except per share amounts)	Year ended December 31, 2001	2000	1999
Income (loss) from continuing operations	$1,090	$(3,324)	$ 13
Discontinued operations	—	(40)	(98)
Net income (loss) before cumulative effect of accounting change	1,090	(3,364)	(85)
Cumulative effect of accounting change	9	—	12
Net income (loss)	$1,099	$(3,364)	$ (73)
Weighted average common shares outstanding	363	362	368
Add: Outstanding options reduced by the number of shares that could be repurchased with the proceeds from such purchase	1	—	1
Shares outstanding for diluted calculations	364	362	369
Earnings (Loss) Per Common Share, Basic			
Income (loss) from continuing operations	$ 3.00	$ (9.18)	$ 0.04
Discontinued operations	—	(0.11)	(0.27)
Cumulative effect of accounting change	0.02	—	0.03
Rounding	0.01	—	—
Net earnings (loss)	$ 3.03	$ (9.29)	$(0.20)
Earnings (Loss) Per Common Share, Diluted			
Income (loss) from continuing operations	$ 2.99	$ (9.18)	$ 0.04
Discontinued operations	—	(0.11)	(0.27)
Cumulative effect of accounting change	0.02	—	0.03
Rounding	0.01	—	—
Net earnings (loss)	$ 3.02	$ (9.29)	$(0.20)

The diluted share base for 2000 excludes incremental shares of 2 million related to employee stock options. These shares are excluded due to the antidilutive effect as a result of the loss from continuing operations. PG&E Corporation reflects the preferred dividends of subsidiaries as other expense for computation of both basic and diluted earnings per share.

Property, Plant and Equipment

Plant additions and replacements are capitalized. The capitalized costs include labor, materials, construction overhead, and capitalized interest or an allowance for funds used during construction (AFUDC). AFUDC is the estimated cost of debt and equity funds used to finance regulated plant additions. Capitalized interest and AFUDC for PG&E Corporation amounted to $18 million, $19 million, and $18 million for the years ended December 31, 2001, 2000, and 1999, respectively. Capitalized interest and AFUDC for the Utility amounted to $18 million, $18 million, and $16 million for the years ended December 31, 2001, 2000, and 1999, respectively. Nuclear fuel inventories are included in property, plant and equipment. Stored nuclear fuel inventory is stated at average cost. Nuclear fuel in the reactor is amortized based on the amount of energy output.

The original cost of retired plant and removal costs less salvage value is charged to accumulated depreciation upon retirement of plant in service for the Utility and PG&E NEG businesses that apply Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," as amended. For the remainder of PG&E NEG business operations, the cost and accumulated depreciation of property, plant and equipment retired or otherwise disposed of is removed from related accounts and included in the determination of the gain or loss on disposition.

Property, plant and equipment are depreciated on a straight-line basis over estimated useful lives, less any residual or salvage value. PG&E Corporation's composite depreciation rates were 3.10 percent, 4.44 percent, and 3.60 percent for the years ended December 31, 2001, 2000, and 1999, respectively. The Utility's composite depreciation rates were 3.63 percent, 4.54 percent, and 3.41 percent for the years ended December 31, 2001, 2000, and 1999, respectively. Estimated useful lives of property, plant and equipment are as follows:

	Utility	PG&E NEG
Electric generating facilities	20 to 50 years	20 to 50 years
Electric distribution facilities	10 to 63 years	N/A
Electric transmission	27 to 65 years	N/A
Gas distribution facilities	28 to 49 years	N/A
Gas transmission	25 to 45 years	15 to 40 years
Gas storage	25 to 48 years	N/A
Other	5 to 38 years	2 to 20 years

The useful life of the Utility's property, plant and equipment complies with CPUC-authorized ranges.

Depreciation rates include a component for the cost of asset retirement net of salvage value. The Utility has a separate component for accrual of its estimated obligation for nuclear decommissioning which is included in depreciation and decommissioning expense in the financial statements. Included in accumulated depreciation is the net asset retirement obligations that have been accrued. In August 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, "Accounting for Asset Retirement Obligations," which will be effective for fiscal years beginning after June 15, 2002. SFAS No. 143 provides accounting requirements for obligations associated with asset retirements, including nuclear decommissioning. Under the Statement, the estimated obligation for retirement of long-lived assets and the associated asset retirement costs, including nuclear decommissioning is recorded as a liability at fair value (rather than as accumulated depreciation) by increasing the carrying amount of the property and plant. The liability is accreted to its present value in each period, and the carrying amount of property and plant is depreciated over the estimated useful lives. PG&E Corporation and the Utility are currently evaluating the impact of SFAS No. 143, but have not yet determined the effects of this Statement on their financial statements.

Investment in Unconsolidated Affiliates

PG&E NEG has investments in various power generation facilities and other energy projects. The equity method of accounting is applied to such investments, which include corporations, joint ventures, and partnerships, due to the ownership structure preventing PG&E NEG from exercising control. Under this method, PG&E NEG's share of income or losses of these entities is reflected as revenue in the accompanying financial statements. PG&E NEG's share of ownership in these affiliates ranges from 5 percent to 64 percent, and its net investment amounted to $414 million and $417 million as of December 31, 2001, and 2000, respectively. Net gains from the sale of interests in unconsolidated affiliates were $0, $21 million, and $19 million for the years ended December 31, 2001, 2000, and 1999, respectively and are included in energy, commodities and services revenue.

The following table sets forth summarized financial information of PG&E NEG's investment in affiliates accounted for under the equity method:

	Year ended December 31,		
(in millions)	2001	2000	1999
Revenues	$1,150	$1,252	$1,067
Income from operations	482	491	524
Earnings before taxes	295	197	149
Equity in earnings of affiliates	79	65	63

	As of December 31,	
(in millions)	2001	2000
Assets	$3,873	$3,889
Liabilities	3,348	3,345

The reconciliation of PG&E NEG's share of equity to investment balance is as follows:

(in millions)	As of December 31, 2001	2000
PG&E NEG's share of equity	$112	$122
Purchase premium over book value	131	136
Lease receivables and other investments	171	159
Investments in unconsolidated affiliates	$414	$417

The purchase premium over book value is being amortized over periods ranging from 16 to 35 years and is recorded through amortization expense. The purchase premium amortization expenses were $7 million, $7 million, and $8 million for the years ended December 31, 2001, 2000, and 1999, respectively.

Capitalized Software Costs

Costs incurred during the application development stage of internal use software projects are capitalized to property, plant and equipment. At December 31, 2001, and 2000, capitalized software costs totaled $255 million and $235 million, net of $119 million and $80 million of accumulated amortization, respectively. Such capitalized amounts are amortized in accordance with regulatory requirements ratably over the expected lives of the projects when they become operational, over periods ranging from 3 to 15 years.

Gains and Losses on Reacquired Debt

Gains and losses on reacquired debt 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 ratemaking principles. Gains and losses on reacquired debt associated with unregulated operations are recognized in earnings as extraordinary gains or losses at the time such debt is reacquired.

Intangible Assets and Asset Impairment

PG&E Corporation amortizes the excess of purchase price over fair value of net assets of businesses acquired (goodwill) using the straight-line method over periods ranging from 3 to 40 years. PG&E Corporation periodically assesses goodwill and intangible assets for potential impairment. The amount of goodwill reported under noncurrent assets in the Consolidated Balance Sheets as of December 31, 2001, and 2000 was $95 million and $100 million, net of accumulated amortization of $30 million and $25 million, respectively.

PG&E Corporation and the Utility periodically evaluate long-lived assets, including property, plant and equipment, goodwill, and specifically identifiable intangible assets, when events or changes in circumstances indicate that the carrying value of these assets may be impaired. The determination of whether impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets.

In addition, SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of," amends SFAS No. 71 and requires PG&E Corporation and the Utility to write off regulatory assets when they are no longer probable of recovery. On an ongoing basis, PG&E Corporation and the Utility review their regulatory assets and liabilities for the continued applicability of SFAS No. 71 and the effect of SFAS No. 121. In connection with such a review, the Utility wrote off $6.9 billion of regulatory assets in December 2000 (see Note 3).

Regulation and Statement of Financial Accounting Standards No. 71

PG&E Corporation and the Utility account for the financial effects of regulation in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." 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 (NRC), among others. The gas transmission business in the Pacific Northwest is also regulated by the FERC.

SFAS No. 71 provides for the recording of 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.

Regulatory assets comprise the following:

(in millions)	Balance at December 31, 2001	Balance at December 31, 2000
Rate reduction bonds (Note 10)	$1,636	$1,178
Unamortized loss, net of gain, on reacquired debt	322	342
Regulatory assets for deferred income tax	188	160
Other, net	137	36
Total Utility regulatory assets	2,283	1,716
PG&E GTN	36	57
Total PG&E Corporation regulatory assets	$2,319	$1,773

Regulatory assets are charged to expense during the period that the costs are reflected in regulated revenues. At December 31, 2001, substantially all of the Utility's regulatory assets were being reflected in rates charged to customers.

The Utility's regulatory asset related to Rate Reduction Bonds will be amortized simultaneously with the amortization of the Rate Reduction Bonds, and will be fully recovered by the end of 2007. The Utility's regulatory asset related to the unamortized loss, net of gain, on reacquired debt will be recovered concurrently with the amortization of the reacquired debt over periods ranging from 1 to 25 years. The Utility's regulatory assets related to deferred income tax will be recovered over the period of reversal of the accumulated deferred taxes to which they relate. 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 39 years.

In general, the Utility does not earn a return on regulatory assets where the related costs do not accrue interest. At December 31, 2001, the Utility did not earn a return on regulatory assets related to recording deferred taxes of $188 million. As of December 31, 2001, and 2000, substantially all of the Utility's regulatory liabilities were related to employee benefit plans and are included in other noncurrent liabilities. These balances will be charged against expense to the extent that future costs recorded for financial reporting purposes exceed amounts recoverable for regulatory purposes.

If portions of the operations no longer become subject to the provisions of SFAS No. 71, a write-off of related regulatory assets and liabilities would be required, unless some form of transition cost recovery continues through rates established and collected for the remaining regulated operations. In addition, PG&E Corporation and the Utility would be required to determine any impairment to the carrying costs of deregulated plant and inventory assets.

Regulatory Balancing Accounts

Sales balancing accounts accumulate differences between authorized and recorded revenues. Cost balancing accounts accumulate differences between recorded costs and recorded revenues designated for recovery of such costs. Under-collections are recorded as regulatory balancing account assets. Over-collections are recorded as regulatory balancing account liabilities. The Utility's regulatory balancing accounts accumulate balances until they are refunded to or received from Utility customers through authorized rate adjustments.

As a result of the California energy crisis discussed in Note 3, the Utility can no longer conclude that electric generation-related balancing accounts meet the requirements of SFAS No. 71. However, the Utility continues to record balancing accounts associated with its electric distribution and transmission businesses.

The Utility's current regulatory balancing account assets comprise the following:

(in millions)	Balance at December 31, 2001	2000
Gas Revenue Balancing Accounts	$42	$ 3
Gas Cost Balancing Accounts	25	217
Electric Distribution Cost Balancing Accounts	8	2
Total	$75	$222

The Utility's current regulatory balancing account liabilities comprise the following:

(in millions)	Balance at December 31, 2001	2000
Gas Revenue Balancing Accounts	$ 31	$ 28
Gas Cost Balancing Accounts	178	14
Electric Transmission and Distribution Revenue Balancing Accounts	19	127
Electric Transmission and Distribution Cost Balancing Accounts	—	27
Total	$228	$196

Revenue Recognition

Revenues are recorded in accordance with the Securities and Exchange Commission (SEC's) Staff Accounting Bulletin (SAB) No. 101, "Revenue Recognition," as amended.

Energy commodities and services revenues derived from power generation are recognized upon output, product delivery, or satisfaction of specific targets, all as specified by contractual terms. Regulated gas transmission revenues are recorded as services are provided, based on rate schedules approved by the FERC. In accordance with Emerging Issues Task Force (EITF) 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management," and SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," certain energy trading contracts are recorded at fair value using mark-to-market accounting. Revenues derived from energy trading activities are reported on a "gross" basis when realized, as provided for in EITF 98-10. Unrealized gains (losses) from trading operations are reported as revenues on a net basis. Electric utility revenues which are comprised of generation, transmission, and distribution services are billed to the Utility's customers at the CPUC approved "bundled" electricity rate. Utility revenues are recognized as gas and electricity are delivered and include amounts for services rendered but not yet billed at the end of each year. Unbilled revenues amounted to $486 million, $485 million, and $378 million at December 31, 2001, 2000, and 1999, respectively.

Accounting for Price Risk Management Activities

PG&E Corporation, primarily through its subsidiaries, engages in price risk management activities for both trading and non-trading purposes. PG&E Corporation conducts trading activities principally through its unregulated lines of business. Trading activities are conducted to generate profit, create liquidity, and maintain a market presence. Net open positions often exist or are established due to PG&E NEG's assessment of and response to changing market conditions. Non-trading activities are conducted to optimize and secure the return on risk capital deployed within PG&E NEG's existing asset and contractual portfolio. In addition, non-trading activity exists within the Utility to hedge against price fluctuations of electricity and natural gas.

Derivative and other financial instruments associated with trading activities in electric power, natural gas, natural gas liquids, fuel oil, coal, gas transportation, storage, and emissions are accounted for using the mark-to-market method of accounting in accordance with EITF 98-10. Under mark-to-market accounting, PG&E Corporation's trading contracts, including both physical contracts and financial instruments, are recorded at market value, which approximates fair value. The methodology used to value these transactions reflect management's best estimates considering various factors, including market quotes, forward price curves, time value, and volatility factors of the underlying commitments. The values are adjusted to reflect the potential impact of liquidating a position in an orderly manner over a reasonable period of time under present market conditions and to reflect creditworthiness of individual counterparties.

Changes in the market value of these trading contract portfolios, resulting primarily from newly originated transactions and the impact of commodity prices or interest rate movements, are recognized in operating income in the period of change. Unrealized gains and losses on trading contract portfolios are recorded as assets and liabilities, respectively, from price risk management. On a realized basis, PG&E Corporation recognizes trading contracts on a gross basis. Sales are recognized in operating revenues and purchases are recognized in operating expenses as costs of commodity sales and fuel.

In addition to the trading activities, as discussed previously, PG&E Corporation and the Utility engage in non-trading activities using futures, forward contracts, options, swaps and other contracts to hedge the impact of market fluctuations on energy commodity prices, interest rates, and foreign currencies when there is a high degree of correlation between price movements in the derivative and the item designated as being hedged. Before the implementation of SFAS No. 133, as described below, PG&E Corporation and the Utility accounted for hedging activities under the deferral method, whereby unrealized gains and losses on hedging transactions were deferred. When the underlying item settled, PG&E Corporation and the Utility recognized the gain or loss from the hedge instrument in operating income. In instances where the anticipated correlation of price movements did not occur, hedge accounting was terminated and future changes in the value of the derivative were recognized as gains or losses. If the hedged item was sold, the value of the associated derivative was recognized in income.

Effective January 1, 2001, PG&E Corporation and the Utility adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities" (collectively, SFAS No. 133). SFAS No. 133 requires PG&E Corporation and the Utility to recognize all derivatives, as defined, on the balance sheet at fair value. PG&E Corporation's transition adjustment to implement SFAS No. 133 on January 1, 2001, resulted in a non-material decrease to earnings and an after-tax decrease of $243 million to accumulated other comprehensive income. The Utility's transition adjustment to implement SFAS No. 133 resulted in a non-material decrease to earnings and an after-tax $90 million positive adjustment to accumulated other comprehensive loss. These transition adjustments, which relate to hedges of interest rate, foreign currency, and commodity price risk exposure, were recognized as of January 1, 2001, as a cumulative effect of a change in accounting principle.

Derivatives are classified as price risk management assets and price risk management liabilities on the balance sheet. Derivatives, or any portion thereof, that are not effective hedges are adjusted to fair value through income. For derivatives that are effective hedges, depending on the nature of the hedge, changes in the fair value are either offset by changes in the fair value of the hedged assets or liabilities through earnings or recognized in accumulated other comprehensive income (loss) until the hedged item is recognized in earnings. Net gains or losses on derivative instruments recognized for the year ended December 31, 2001, were included in various lines on the Consolidated Statements of Operations, including energy commodities and services revenue, cost of energy commodities and services, interest income or interest expense, and other income (expense), net.

PG&E Corporation also has derivative commodity contracts for the physical delivery of purchase and sale quantities transacted in the normal course of business. These derivatives are exempt from the requirements of SFAS No. 133 under the normal purchase and sales exception, and are not reflected on the balance sheet at fair value. In June 2001 (as amended in October 2001 and December 2001), the FASB approved an interpretation issued by the Derivatives Implementation Group (DIG) that changed the definition of normal purchases and sales for certain power contracts. PG&E Corporation must implement this interpretation on April 1, 2002, and is currently assessing the impact of these new rules. PG&E Corporation anticipates that implementation of this interpretation will result in several contracts' failure to continue qualifying for the normal purchases and sales exemption, possibly resulting in these contracts being marked-to-market through earnings. The FASB has also approved another DIG interpretation that disallows normal purchases and sales treatment for commodity contracts (other than power contracts) that contain volumetric variability or optionality. Certain of PG&E Corporation's derivative commodity contracts may no longer be exempt from the requirements of the Statement. PG&E Corporation is evaluating the impact of this implementation guidance on its financial statements, and will implement this guidance, as appropriate, by the implementation deadline of April 1, 2002.

To qualify for the normal purchases and sales exemption from SFAS No. 133, a contract must have pricing that is deemed to be clearly and closely related to the asset to be delivered under the contract. In 2001, the FASB approved another interpretation issued by the DIG that clarifies how this requirement applies to certain commodity contracts. In applying this new DIG guidance, PG&E Corporation determined that one of its derivative commodity contracts no longer qualifies for normal purchases and sales treatment, and must be marked-to-market through earnings. The cumulative effect of this change in accounting principle increased earnings by approximately $9 million (after-tax).

As of December 31, 2001, the maximum length of time over which PG&E Corporation had hedged its exposure to the variability in future cash flows associated with commodity price risk is through December 2006. The maximum length of time over which PG&E Corporation has hedged its exposure to the variability in future cash flows associated with interest rate risk is through March 2014.

The Utility is party to various electric and gas bilateral contracts, some of which were terminated in the first six months of 2001 (see Note 15). The value of certain financial gas contracts terminated during the first six months of the year was being amortized out of accumulated other comprehensive income (loss) over the life of the related physical contracts previously being hedged, in accordance with the provisions of SFAS No. 133. Through the second quarter of 2001, the Utility had amortized $20 million of losses associated with these contracts. Those losses were partially offset through the second quarter of 2001 by gains from the hedged transactions. In the third quarter of 2001, a $66 million (after-tax) loss associated with the terminated contracts included primarily in accumulated other comprehensive loss was recognized in earnings. The loss was recognized in earnings due to changes in market conditions that made it unlikely that this loss would be offset when the related physical contracts are recognized in earnings. SFAS No. 133 requires an entity to immediately reclassify into earnings amounts in accumulated other comprehensive income (loss) that are not expected to be recovered when the hedged transactions are recognized in earnings in future periods.

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. PG&E Corporation's and the Utility's accumulated other comprehensive income (loss) consists principally of changes in the market value of certain cash flow hedges with the implementation of SFAS No. 133 on January 1, 2001, as well as foreign currency translation adjustments.

Accounting for Major Maintenance

Effective January 1, 1999, PG&E Corporation changed its method of accounting for major maintenance and overhauls of generating assets at PG&E NEG. Beginning January 1, 1999, the cost of major maintenance and overhauls of generating assets, principally at the PG&E Gen business segment, were accounted for as incurred. Previously, the estimated cost of major maintenance and overhauls was accrued in advance in a systematic and rational manner over the period between major maintenance and overhauls. The cumulative effect of this accounting change resulted in PG&E Corporation recording income of $12 million net of income tax ($0.03 per share) as of December 31, 1999, reflecting the cumulative effect of the change in accounting principle. The Utility has consistently accounted for major maintenance and overhauls as incurred.

Related Party Agreements

In accordance with various agreements, the Utility and other subsidiaries provide and receive various services to and from their parent, PG&E Corporation. The Utility and PG&E Corporation exchange administrative and professional support services in support of operations. These services are priced either at the fully loaded cost or at the higher of fully loaded cost or fair market value depending on the nature of the services provided. PG&E Corporation also allocates certain other corporate administrative and general costs to the Utility and other subsidiaries using a variety of factors which are based upon the number of employees, operating expenses, excluding fuel purchases, total assets, and other cost causal methods. Additionally, the Utility purchases gas commodity and transmission services from, and sells reservation and other ancillary services to PG&E NEG. These services are priced at either tariff rates or fair market value depending on the nature of the services provided.

Intercompany transactions are eliminated in consolidation and no profit results from these transactions. The Utility's significant related party transactions were as follows:

(in millions)	Year ended December 31, 2001	2000	1999
Utility revenues from:			
Administrative services provided to PG&E Corporation	$ 6	$ 12	$ 23
Transportation and distribution services provided to PG&E ES	—	—	134
Gas reservation services provided to PG&E ET	11	12	7
Other	1	2	3
Utility expenses from:			
Administrative services received from PG&E Corporation	$127	$ 83	$ 66
Gas commodity and transmission services received from PG&E ET	120	136	30
Transmission services received from PG&E GT	41	46	47

Stock-Based Compensation

PG&E Corporation accounts for stock-based compensation using the intrinsic value method in accordance with the provisions of Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees," as allowed by SFAS No. 123, "Accounting for Stock-Based Compensation." Under the intrinsic value method, PG&E Corporation does not recognize any compensation expense, as the exercise price of all stock options is equal to the fair market value at the time the options are granted. Had compensation expense been recognized using the fair value-based method under SFAS No. 123, PG&E Corporation's pro forma consolidated earnings (loss) and earnings (loss) per share would have been as follows:

(in millions, except per share amounts)	2001	2000	1999
Net earnings (loss):			
As reported	$1,099	$(3,364)	$ (73)
Pro-forma	1,076	(3,374)	(79)
Basic earnings (loss) per share:			
As reported	3.03	(9.29)	(0.20)
Pro-forma	2.96	(9.32)	(0.21)
Diluted earnings (loss) per share:			
As reported	3.02	(9.29)	(0.20)
Pro-forma	2.96	(9.32)	(0.21)

Reclassifications

Certain amounts in the 2000 and 1999 financial statements have been reclassified to conform to the 2001 presentation.

Note 2: Voluntary Petition For Relief Under Chapter 11 and Plan of Reorganization

As discussed further in Note 3, as a result of (1) the failure of the California Department of Water Resources (DWR) to assume the full procurement responsibility for the Utility's net open position, (2) the negative impact of a CPUC decision that created new payment obligations for the Utility and undermined its ability to return to financial viability, (3) the lack of progress in negotiations with the State of California to provide a solution for the energy crisis, and (4) the adoption by the CPUC of a retroactive accounting change that would appear to eliminate the Utility's true under-collected wholesale electricity costs, the Utility filed in the Bankruptcy Court a voluntary petition for relief under Chapter 11 of the Bankruptcy Code on April 6, 2001. Under Chapter 11, the Utility retains control of its assets and is authorized to operate its business as a debtor-in-possession while being subject to the jurisdiction of the Bankruptcy Court. Subsidiaries of the Utility, including PG&E Funding LLC (which holds Rate Reduction Bonds) and PG&E Holdings, LLC (which holds stock of the Utility), are not included in the Utility's petition. The Utility's parent, PG&E Corporation, and PG&E NEG have not filed for relief under Chapter 11 and are not included in the Utility's petition.

The Utility's Consolidated Financial Statements have been prepared in accordance with the American Institute of Certified Public Accountants' Statement of Position (SOP) 90-7, "Financial Reporting by Entities in Reorganization Under the Bankruptcy Code," and on a going-concern basis, which contemplates continuity of operation, realization of assets and liquidation of liabilities in the ordinary course of business. However, as a result of the Chapter 11 filing, such realization of assets and liquidation of liabilities are subject to uncertainty.

Certain claims against the Utility in existence prior to its filing of the petition for relief are stayed while the Utility continues business operations as a debtor-in-possession. The Utility has reflected its total estimate of all such valid claims in the December 31, 2001, Consolidated Balance Sheets as $11.4 billion of Liabilities Subject to Compromise and as $3.4 billion of Long-Term Debt. Additional claims or changes to Liabilities Subject to Compromise may subsequently arise resulting from, among other things, resolution of disputed claims and Bankruptcy Court actions. Payment terms for these amounts will be established through the bankruptcy proceedings. Secured claims also are stayed, although the holders of such claims have the right to move the Bankruptcy Court for relief from the stay. Secured claims are secured primarily by liens on substantially all of the Utility's assets and by pledged accounts receivable from gas customers. The Bankruptcy Court has approved certain payments and actions necessary for the Utility to carry on its normal business operations (including payment of employee wages and benefits, refunds of certain customer deposits, use of certain bank accounts and cash collateral, assumption of various hydroelectric contracts with water agencies and irrigation districts, certain qualifying facilities (QF) payments, interest on secured debt, and continuation of environmental remediation and capital expenditure programs) and to fulfill certain post-petition obligations to suppliers and creditors.

Through September 5, 2001, the last day for non-governmental creditors to file proofs of claim, approximately $42.1 billion of claims had been submitted. This amount includes claims filed by generators (which the Utility believes have been significantly overstated) and claims filed by financial institutions (which the Utility believes contain significant duplication). The Bankruptcy Court so far has disallowed approximately $9 billion of claims filed by non-governmental entities. In addition, through October 3, 2001, the last day for governmental entities to file proofs of claim, approximately $1.9 billion of claims had been submitted. These include, but are not limited to, contingent environmental claims, claims for federal, state, and local taxes, and claims submitted by the DWR for approximately $430 million of energy purchases made on behalf of the Utility's retail customers.

The claims resolution process in bankruptcy involves establishment of the validity of the claim and determination of specifically how the claim is to be discharged. In addition, it is common to negotiate with creditors to achieve settlement. The Utility intends to explore settlement of claims wherever possible.

On September 20, 2001, the Utility and its parent company, PG&E Corporation, jointly filed with the Bankruptcy Court a proposed plan of reorganization of the Utility under the Bankruptcy Code and a proposed disclosure statement describing the proposed Plan. Both the Plan and the disclosure statement were subsequently amended on December 19, 2001 and February 4, 2002, in an effort to resolve objections filed by various parties. If the Plan, as amended, is confirmed and becomes effective, it would allow the Utility to restructure its businesses, refinance the restructured businesses, and use the proceeds from the refinancing to pay all valid claims, with interest.

The Plan, which has been endorsed by the Official Committee of Unsecured Creditors (Committee) and another group of senior debtholders, is designed to align the businesses under the regulators that best match the business functions. Retail assets would remain under the retail regulator (CPUC) and wholesale assets would be placed under wholesale regulators the FERC and the NRC. After this alignment, the retail-focused, state-regulated business would be a gas and electric distribution company (Reorganized Utility) representing approximately 70 percent of the book value of the Utility's assets and having approximately 16,000 employees. The wholesale businesses, which would be federally regulated (as to price, terms, and conditions), would consist of electric transmission (ETrans), interstate gas transmission (GTrans), and generation (Gen).

The Plan proposes that certain other assets of the Utility deemed not essential to operations would be sold to third parties or transferred to Newco Energy Corporation (Newco), a consolidated subsidiary created by the Utility to hold the investment in ETrans, GTrans and Gen. Additionally, the Utility would declare and, after the assets are transferred to the newly formed entities, pay a dividend to PG&E Corporation of all of the outstanding common stock of Newco. Each of ETrans, Gtrans, and Gen would continue to be an indirect wholly owned subsidiary of PG&E Corporation.

Finally, the Plan contemplates that on or as soon as practicable after the date on which the Plan becomes effective (Effective Date), PG&E Corporation would distribute the shares of the Reorganized Utility's common stock it holds to the holders of PG&E Corporation common stock on a pro rata basis (Spin-Off). The Utility's currently outstanding preferred stock would remain preferred stock of the Reorganized Utility. It is contemplated that holders of preferred stock would receive on the Effective Date, and in cash, any dividends unpaid and sinking fund payments accrued in respect of such preferred stock through the last scheduled payment date before the Effective Date. The common stock of the Reorganized Utility would be registered pursuant to the Securities Exchange Act of 1934, and would generally be freely tradeable by the recipients on the Effective Date or as soon as practicable thereafter. The Reorganized Utility would apply to list the common stock of the Reorganized Utility on the New York Stock Exchange.

Key aspects of the plan include (1) the issuance of debt by ETrans, GTrans and Gen, the proceeds of which, along with additional notes, would be distributed to the Reorganized Utility so that it could pay creditors, (2) a 12-year bilateral contract whereby Gen provides the Reorganized Utility firm capacity and energy at an average rate of approximately $5.00 per megawatt-hour (MWh), and (3) the assumption by the Reorganized Utility of responsibility for the net open position only after conditions specified in detail below.

As mentioned above, the Plan proposes that all valid creditor claims would be paid in full with interest, using a combination of cash and long-term notes. Interest rates would be 5 percent on payables to QFs, the three-month London Interbank Offering Rate (LIBOR), plus 2 percent on wholesale electricity payables, and the one-year U.S. Treasury Bill rate on affiliate payables and trade payables. Creditors would receive payment as follows:

	On the Effective Day of the Plan, Creditors Would Receive Payment In	
	Cash	Long-Term Notes
Majority of secured creditors	100%	
Majority of unsecured creditors with allowed claims of $100,000 or less	100%	
Unsecured creditors with allowed claims in excess of $100,000	60%	40%

PG&E Corporation and the Utility, through a settlement with a group of senior debtholders, have agreed to pay the holders of certain allowed claims pre- and post-petition interest on the principal amount of such claims at rates of interest which differ from the rates proposed in the Plan, as follows:

(in millions)	Amount Owed	Settlement	Amended Plan of Reorganization
Commercial Paper Claims	$ 873	7.466% per annum	3-month floating LIBOR
Floating Rate Notes	1,240	7.583% per annum	Floating LIBOR plus 2.05%
Senior Notes	680	9.625%	7.375% increased to 9.625% on May 1, 2001
Medium-Term Notes	287	5.81% to 8.45%	Same
Revolving Lines of Credit Claims	938	8.000% per annum	Floating prime rate

In addition, if the Effective Date of the Plan does not occur on or before February 15, 2003, these interest rates will be increased by 37.5 basis points. If the Effective Date of the Plan does not occur on or before September 15, 2003, the agreed rates will be increased by an additional 37.5 basis points. Finally, if the Effective Date of the Plan does not occur on or before March 15, 2004, the agreed rates will be increased by an additional 37.5 basis points.

In December 2001, and January 2002, the Bankruptcy Court approved supplemental agreements entered into between the Utility and several QFs to resolve the issue of the applicable interest rate to be applied to the prepetition payables. The supplemental agreements (1) set the interest rate for prepetition payables at 5 percent, (2) provide for a "catch up payment" of all accrued and unpaid interest through December 31, 2001, and (3) provide for an accelerated payment of the principal amount of the prepetition payables (and interest thereon) in 12 equal monthly payments of principal (and interest thereon) commencing on December 31, 2001, and continuing through November 30, 2002, or, in the event the effective date of the Plan occurs before the last monthly payment is made, the remaining unpaid principal and accrued but unpaid interest thereon, shall be paid in full on the Effective Date. The Utility believes that other QFs will also wish to enter into similar supplemental agreements.

Under the Plan, the Reorganized Utility will request that the Bankruptcy Court recognize in its confirmation order or in findings of fact and conclusions of law that the Reorganized Utility is prohibited from reassuming the responsibility to purchase power to meet the net open position not already provided through the DWR's power purchase contracts, until such time as:

1. The Reorganized Utility establishes an investment grade credit rating and receives assurances that its credit rating will not be downgraded as a result of the reassumption of the obligation to meet the net open position;
2. There is an objective retail rate recovery mechanism in place pursuant to which the Reorganized Utility is able to fully recover in a timely manner its wholesale costs of purchasing electricity to meet the net open position;
3. There are objective standards in place regarding pre-approval of procurement transactions; and
4. After reassumption of the obligation to meet the net open position, the conditions in clauses (2) and (3) remain in effect.

On November 30, 2001, the Utility and PG&E Corporation on behalf of its subsidiaries ETrans, GTrans, and Gen, filed various applications with the FERC seeking approval to implement the proposed reorganization and the securities issuances and debt financings contemplated by the Plan. The FERC must also approve the various service agreements to be entered into between the Reorganized Utility and one or more of the disaggregated entities. Additionally, the SEC must approve the Plan as administrator of the Public Utility Holding Company Act (PUHCA). An application under PUHCA was filed with the SEC on January 31, 2002.

Also on November 30, 2001, the Utility filed applications with the NRC for approval to transfer the NRC operating licenses for the Diablo Canyon Nuclear Power Plant (Diablo Canyon) to Gen and one of its subsidiaries, and for the indirect transfer of the Humboldt Bay Nuclear Power Plant (which is in the early stages of decommissioning) to the Reorganized Utility.

Additionally, because the reorganization is intended to qualify as a tax-free reorganization, and the Spin-Off is intended to qualify as a tax-free Spin-Off, PG&E Corporation and the Utility have sought a private letter ruling from the Internal Revenue Service (IRS) confirming the tax-free treatment of these transactions.

The Plan as amended relies on FERC and the Bankruptcy Court to authorize certain actions which are outside of management's control. These actions include allowing a shift in the jurisdiction of certain Utility assets, approving contracts between and among the newly formed entities, and to preempt certain state and local laws. Specifically, the Plan asks the Bankruptcy Court to issue the following orders or make the following findings:

1. Approve the Plan documents, authorizing the Utility to execute, implement and take all actions necessary or appropriate to give effect to the transactions contemplated by the Plan and the Plan documents;
2. Determine that the Utility, PG&E Corporation and their affiliates are not liable or responsible for any DWR power contracts or purchases of power by the DWR, and any liabilities associated therewith;
3. Prohibit the Reorganized Utility from accepting an assignment of the DWR contracts;
4. Prohibit the Reorganized Utility from reassuming the net open position unless the Reorganized Utility is found to be creditworthy (as defined in the Plan documents) and a regulatory mechanism exists for the Reorganized Utility to recover its wholesale power purchases;
5. Approve the execution of the proposed service and sales contracts between the Reorganized Utility and one or more of the disaggregated entities;
6. Find that the CPUC affiliate transaction rules are not applicable to the restructuring transactions;
7. Find that the approval of state and local agencies of California, including but not limited to, the CPUC, shall not be required in connection with the restructuring transactions because the Bankruptcy Code preempts such state and local laws;
8. Find that neither PG&E Corporation nor the Utility is required to comply with certain provisions of the California Corporations Code relating to corporate distributions and the sale of substantially all of a corporation's assets because the Bankruptcy Code preempts such state law;

The Plan provides that it will not become effective unless and until the following conditions shall have been satisfied or waived:

1. The confirmation order, in form and substance acceptable to PG&E Corporation and the Utility, shall have been signed by the Bankruptcy Court on or before June 30, 2002, and shall have become a final order;
2. The Effective Date shall have occurred on or before January 1, 2003;
3. All actions, documents and agreements necessary to implement the Plan shall have been effected or executed;
4. PG&E Corporation and the Utility shall have received all authorizations, consents, regulatory approvals, rulings, letters, no-action letters, opinions or documents that are determined by PG&E Corporation and the Utility to be necessary to implement the Plan;
5. Standard & Poors (S&P) and Moody's Investors Service (Moody's) shall have established credit ratings for each of the securities to be issued by the Reorganized Utility, ETrans, GTrans, and Gen of not less than BBB- and Baa3, respectively;
6. The Plan shall not have been modified in a material way since the confirmation date; and
7. The registration statements pursuant to which the new securities will be issued shall have been declared effective by the SEC, the Reorganized Utility shall have consummated the sale of its new securities to be sold under the Plan, and the new securities of each of ETrans, GTrans, and Gen shall have been priced and the trade date with respect to each shall have occurred.

If one or more of the conditions described above have not occurred or been waived by January 1, 2003, the confirmation order shall be vacated and the Utility's obligations with respect to claims and equity interests shall remain unchanged.

On January 16, 2002, the Bankruptcy Court issued an order granting the Utility's motion to extend the period during which only the Utility has the right to submit a proposed plan of reorganization from February 4, 2002, when the period would otherwise expire, to June 30, 2002. The Bankruptcy Court's order also granted the CPUC's request to submit a term sheet describing the CPUC's alternative proposed plan of reorganization (CPUC Plan) and required that the CPUC submit a term sheet.

On February 7, 2002, the Bankruptcy Court issued an order concluding that bankruptcy law does not expressly preempt state law in connection with the implementation of a plan of reorganization. Instead, the Bankruptcy Court interpreted the applicable bankruptcy law to impliedly preempt state law where it has been shown that enforcing the state law at issue would be an obstacle to the accomplishment and execution of the full purposes of the bankruptcy laws. The Bankruptcy Court stated that whether a restructuring, i.e., the disaggregation of the Utility's businesses as proposed in the Plan, is necessary and required for a feasible reorganization is an issue to be determined at the confirmation hearing.

The Bankruptcy Court provided guidance as to how the Plan could be amended to obtain court approval so that the stage would be set for the "implied preemption confirmation contest." PG&E Corporation and the Utility plan to revise the Plan to state in summary fashion the reasons why it is necessary to preempt the laws, regulations or orders referred to above. PG&E Corporation and the Utility will have to prove at the confirmation hearing that those particular laws stand as an obstacle to the accomplishment and execution of the purposes and objectives of the bankruptcy laws.

On February 13, 2002 the CPUC filed with the Bankruptcy Court a term sheet depicting its alternative plan of reorganization. The CPUC's term sheet does not call for realignment of the Utility's business and provides for the continued regulation of all of the Utility's current operations by the CPUC. Other significant components of the CPUC's plan include:

- Prohibits the Utility from declaring or making cash distributions to PG&E Corporation (including by way of dividends and stock repurchases) through 2003;
- Provides for shareholders to contribute a projected $1.2 billion from the return on rate base for the period December 1, 2001, through January 3, 2003;
- Assumes the Utility will satisfy FERC's creditworthiness requirements and will resume purchasing the net open position no later than January 2003;

- Keeps current Utility rates in effect until no later than January 31, 2003, the assumed effective date of the CPUC plan. After all debts are paid in full, or reinstated, the CPUC would establish a cost of service rate structure;
- Establishes a Litigation Trust for the benefit of the Utility's customers which would be funded with (1) cash in an amount to be determined from the Utility, and (2) proceeds from settlement of various claims and causes of action including: (a) claims against PG&E Corporation (See Order Instituting Investigation (OII) into Holding Company Activities and Attorney General Complaint in Regulatory Matters), (b) refund claims from electric generators pending before FERC, if any, (c) other claims against electric generators, and (d) up to the first $1.75 billion of proceeds from the federal lawsuit filed by the Utility against the CPUC (See Federal Lawsuit in Regulatory Matters);
- Assumes all valid claims (together with post petition interest at the lowest non-default contract rate, or if no contract or non-default rate exists, then the federal judgment rate) will be satisfied in full through a combination of cash (estimated to be $6.9 billion by January 31, 2003), and reinstatement of certain of the Utility's long-term indebtedness and other obligations (approximately $5.8 billion); and
- Assumes the Utility will obtain a credit facility to fund capital expenditures, working capital, and if necessary, distributions to unsecured creditors.

The CPUC's proposed timeline from its alternate plan provides for confirmation hearings to begin on or before September 16, 2002 and for the plan to become effective on or before January 31, 2003.

PG&E Corporation and the Utility do not believe the CPUC's plan is credible because it overstates the available cash, understates the debt and other obligations, and undermines the Utility's ability to invest in electrical system reliability. PG&E Corporation and the Utility also do not believe the CPUC's plan will restore the Utility to investment grade status when the plan becomes effective. On February 27, 2002, the Bankruptcy Court decided to permit the CPUC to formally file its proposal plan. The CPUC must submit its alternative plan by April 15, 2002.

PG&E Corporation and the Utility are unable to predict whether the Bankruptcy Court will confirm the Plan, whether the Bankruptcy Court will confirm the CPUC's alternative plan, or whether other parties may file an alternative plan of reorganization after June 30, 2002, when the period during which only the Utility (except the CPUC) may file a proposed plan will expire. Consideration of alternative plans could cause delays in the Plan's current schedule. PG&E Corporation and the Utility cannot predict what will be in these other parties' plans or whether they will be confirmed by the Bankruptcy Court. Further, assuming the Bankruptcy Court confirms the Plan, implementation may be impacted by appeals, which could also cause delays. Accordingly, the filing for bankruptcy protection and the related uncertainty around the plan of reorganization that is ultimately adopted will have a significant impact on the Utility's future liquidity and results of operations. The Utility is not able at this time to predict the outcome of its bankruptcy case, or the effect of the reorganization process on the claims of the creditors of the Utility or the interests of the Utility's preferred security holders. However, the Utility believes, based on information presently available to it, that cash and cash equivalents on hand at December 31, 2001, of $4.3 billion and cash available from operations will provide sufficient liquidity to allow it to continue as a going concern through 2002.

Note 3: California Electric Industry Restructuring

In 1998, California implemented electric industry restructuring and established a market framework for electric generation in which generators and other power providers were permitted to charge market-based prices for wholesale power. The restructuring of the electric industry was mandated by the California Legislature in Assembly Bill (AB) 1890. The electric industry restructuring law mandated a rate freeze and included a plan for recovery of generation-related costs that were expected to be uneconomic under the new market framework (transition costs). Additionally, the CPUC strongly encouraged the Utility to divest greater than 50 percent of its fossil generation facilities and discouraged the Utility from continuing to operate remaining generation facilities by reducing the allowed return on such assets. The new market framework called for the creation of the Power Exchange (PX) and the Independent System Operator (ISO). Before it ceased operating in March 2001, the PX established market-clearing prices for electricity. The ISO's role was to schedule delivery of electricity for all market participants and operate certain markets for electricity. Until December 15, 2000, the Utility was required to sell all of its owned and contracted generation to, and purchase all electricity for its retail customers from, the PX. Customers were given the choice of continuing to buy electricity from the Utility or buying electricity from independent power generators or retail electricity suppliers. Most of the Utility's customers continued to buy electricity through the Utility.

Beginning in June 2000, wholesale spot prices for electricity sold through the PX and ISO began to escalate. While forward and spot prices moderated somewhat in September and October 2000, such prices skyrocketed in November and December 2000 to levels substantially higher than during the summer months. The average price of electricity purchased by the Utility through the PX for the benefit of its customers was $0.182 per kilowatt-hour (kWh) for the period June 1 through December 31, 2000, compared to $0.042 per kWh during the same period in 1999. The Utility was only permitted to collect approximately $0.054 per kWh through the frozen generation-related component of electric retail rates from its customers during that period. The increased cost of the purchased electricity strained the financial resources of the Utility, and because of the rate freeze, the Utility was unable to pass on the increases in power costs to its customers.

The rate freeze is scheduled to end on the earlier of March 31, 2002, or the date the Utility recovers all of its transition costs as determined by the CPUC. Under the electric industry restructuring framework, the Utility is entitled to recover its FERC-authorized wholesale purchased power costs from ratepayers. During the rate freeze, the Utility has been unable to recover its wholesale purchased power costs. However, once the rate freeze ends, the Utility would be able to directly pass on its wholesale electricity costs to retail customers. The Utility believes it recovered its eligible transition costs during August 2000 or potentially earlier as a result of recording a credit to the Utility's account for tracking the recovery of transition costs in recognition of the fair market value of the Utility's hydroelectric generation facilities per instruction from the CPUC. The Utility continued to finance the higher costs of wholesale electric power while interested parties evaluated various solutions to the California energy crisis. Consequently, by December 31, 2000, the Utility had borrowed more than $3 billion under its various credit facilities to finance its wholesale energy purchases.

In November 2000, the Utility filed a proposed Rate Stabilization Plan (RSP), which sought to end the rate freeze and thereby enable the Utility to pass on the increased wholesale electricity costs to customers through increased rates. The CPUC evaluated the Utility's proposal, and on January 4, 2001, denied the Utility's request for a rate increase. Instead, the CPUC allowed the Utility to establish an interim energy procurement surcharge of $0.010 per kWh, to remain in effect for 90 days from the effective date of the decision. This increase, which could not be used to recover past procurement costs, was not sufficient to cover the higher wholesale costs of electricity. On March 27, 2001, the CPUC authorized the Utility to add an average $0.030 per kWh surcharge to its current rates and made the January $0.010 per kWh surcharge permanent. These new rates were reflected in customers' bills beginning in June 2001.

Because of escalating wholesale electricity costs and the inability to pass on these costs to retail customers, the Utility accumulated a total of approximately $6.9 billion in under-collected power costs and generation-related transition costs as of December 31, 2000. The under-collected purchased power costs generally would be deferred for future recovery as a regulatory asset subject to future collection from customers in rates. However, due to the lack of regulatory, legislative, and judicial relief, the Utility determined that it could no longer conclude that its under-collected wholesale electricity costs and remaining transition costs were probable of recovery in future rates. Therefore, the Utility charged $6.9 billion to earnings for the under-collected electricity costs and the remaining unamortized transition costs at December 31, 2000. During the first quarter of 2001, the Utility incurred over $1 billion of additional unrecovered purchased power costs, based on ISO billings. During 2001, the Utility expensed all power generation and procurement costs as incurred. Beginning in the second quarter of 2001, the price of wholesale electricity stabilized. Additionally, the Utility began collecting from its customers the electricity surcharge pursuant to the January and March 2001, decisions of the CPUC. In 2001, the Utility's generation-related electric revenues were greater than its generation-related costs, resulting in an increase to earnings of $458 million, which represents the partial recovery of previously written-off generation-related transition costs.

On February 27, 2002, The Utility Reform Network (TURN) and other ratepayers filed a complaint with the CPUC asking the CPUC to order a reduction in the Utility's current electric rates and refund allegedly excessive surcharge revenues the Utility has collected since June 2001, pursuant to the CPUC's March 2001 order.

Further affecting the recovery of transition costs and the end of the rate freeze, in March 2001, the CPUC adopted an accounting proposal introduced by TURN. This proposal required the transfer on a monthly basis of the balance in the Utility's Transition Revenue Account (TRA), whether under-collected or over-collected, to the Transition Cost Balancing Account (TCBA). The TRA is a regulatory balancing account that records the generation-related component of electric revenues collected from ratepayers through frozen rates and the wholesale electricity costs. To the extent that costs exceed revenues, the TRA is under-collected. To the extent that revenues exceed costs, the TRA is over-collected. The TCBA is a regulatory balancing account that tracks the recovery of generation-related transition costs. Generally, all transition costs had to be recovered by December 31, 2001 or they would not be recovered at all under the regulatory framework. Prior to the adoption of the TURN proposal, to the extent that the TRA was over-collected, the balance in the TRA would be transferred to the TCBA in order to recover remaining transition costs. The TURN proposal, however, required that to the extent that the TRA was under-collected, the balance in the TRA would also be transferred to the TCBA. The CPUC required that these accounting changes be applied retroactively to January 1, 1998. The Utility believes the CPUC is retroactively transforming the under-collected wholesale electricity costs in the TRA into additional transition costs in the TCBA. This could extend the rate freeze period beyond the period that the Utility contends it ended. Further, the CPUC found that as a result of these accounting changes, the conditions for ending the rate freeze have not been met.

The Utility filed an application for rehearing of the CPUC's retroactive accounting change. In January 2002, the CPUC issued a decision, which denied the application for rehearing of the retroactive accounting change (but grants a rehearing on the issue of whether the rate freeze should be ended). Nonetheless, the CPUC's decision does not alter or otherwise affect the amount or nature of wholesale electricity procurement and transition costs that the Utility has incurred or the amount of the Utility's generation-related component of electric retail revenues available to pay for those wholesale costs. The Utility believes that the retroactive accounting change decision violates AB 1890, and that the CPUC's authority constitutes an unconstitutional taking of the Utility's property, violates the Utility's federal and state due process and equal protection rights, and constitutes unlawful retroactive ratemaking. The Utility requested that the Bankruptcy Court bar the CPUC from requiring the Utility to implement the regulatory accounting changes.

On June 1, 2001, the Bankruptcy Court denied the Utility's application for a preliminary injunction, and an appeal of the Bankruptcy Court's decision is now pending. The Utility also believes that federal law requires the CPUC to provide relief to the Utility upon notice that the Utility's authorized rates are insufficient to recover its operating costs and that the CPUC is prohibited from disallowing wholesale electricity costs that have been authorized by FERC. The Utility has filed suit against the CPUC in federal court seeking the court to enforce the Filed Rate Doctrine and find that the federally approved wholesale electricity costs the Utility has incurred to serve its customers are recoverable in retail rates both before and after the end of the transition period. On November 26, 2001, this case was consolidated with the appeal of the Bankruptcy Court's denial of the Utility's application for a preliminary injunction. A case management conference in both actions is scheduled for March 7, 2002.

Generation Divestiture

Under the California electric industry restructuring legislation mandated by AB 1890, transition costs can be recovered through the portion of the market value in excess of book value of generation assets sold by the Utility or market valued by the CPUC. Additionally, Section 367 of AB 1890 required that the market valuation of these remaining generation assets (primarily hydroelectric facilities) be completed by December 31, 2001 (see further discussion below).

In April 1999, the Utility sold three fossil-fueled generation plants for $801 million. At the time of sale, these three fossil-fueled plants had a combined book value of $256 million and a combined capacity of 3,065 megawatts (MW).

In May 1999, the Utility sold its complex of geothermal generation facilities for $213 million. At the time of sale, these facilities had a combined book value of $244 million and a combined capacity of 1,224 MW. The Lake facility was sold at a gain of $8 million, while the Sonoma facility was sold at a loss of $39 million.

The Utility has retained a liability for required environmental remediation related to any pre-closing soil or groundwater contamination at the plants it has sold.

In January 2001, AB 6X was passed which prohibits disposal of any of the Utility's generation facilities, including the hydroelectric facilities, prior to January 1, 2006. On December 21, 2001, the Assigned Commissioner issued a ruling indicating that the requirement of AB 1890 to market value retained generation by December 31, 2001, had been superseded by AB 6X. On January 15, 2002, the Utility filed comments reiterating the reasons contained in previous pleadings as to why the enactment of AB 6X did not supersede or repeal the CPUC's statutory obligation to market value the utility's generation assets by December 31, 2001.

The Utility's Retained Generation Ratemaking Proceeding

In June 2001, the Utility filed its proposed ratemaking for retained utility generation facilities and procurement costs still incurred by the Utility. The Utility's proposal requested that the ratemaking for its retained generating facilities be set in accordance with previous and still effective CPUC decisions that, under AB 1890, the costs of generation subsequent to December 31, 2001, are to be recovered from the marketplace. AB 1890 allows the Utility to offset transition costs by the market value in excess of book value of the retained non-nuclear generating facilities. Accordingly, the Utility has submitted proposed market valuations of non-nuclear generating facilities. Absent the ability to make marketplace sales, the Utility believes that the retained generation revenue requirement should be based upon whatever market value is credited against transition cost recovery for its non-nuclear generation facilities. Further, the Utility believes that the ratemaking for the Utility's Diablo Canyon facility should be based on a specific "benefit sharing" formula established in a 1997 CPUC decision. Under the formula, the Utility would share 50 percent of the net operating benefits or costs of operating Diablo Canyon after the transition period. The Incremental Cost Incentive Price (ICIP) ratemaking for Diablo Canyon used to recover the Diablo Canyon facility's operating costs and the cost of capital additions incurred after December 31, 1996 was originally scheduled to end December 31, 2001.

On October 25, 2001, the CPUC issued a decision denying the Utility's request that the market value of its retained utility generating facilities be used to establish prospective ratemaking for those facilities. The CPUC said its decision did not address how to treat past uneconomic costs incurred by the Utility and that when issues concerning the termination of the rate freeze are resolved, the CPUC should address any impacts on ratemaking for the Utility's retained generation. Hearings to present evidence and testimony were concluded in July 2001. On January 18, 2002, the CPUC issued a proposed decision establishing the Utility's retained generation revenue requirement for 2002. The proposed decision adopts a cost-based 2002 generation revenue requirement for the Utility of $2,875 million subject to true-up to reflect actual recorded costs. In addition, the proposed decision rejects the "benefit sharing" ratemaking for Diablo Canyon in favor of cost-based rates. The proposed decision does not reset rates and substantially ignores the Utility's proposed ratemaking, including its proposed monthly true-up of operating and maintenance costs.

On February 7, 2002, a CPUC Commissioner issued an alternate proposed decision (AD) regarding the Utility's retained generation revenue requirement proceeding which proposes not to reject benefits sharing for Diablo Canyon but would defer that decision to another proceeding. The AD also notes that the ICIP for Diablo Canyon would continue until the Utility has recovered its transition costs, and implies that ICIP is tied to recovery of transition costs. The AD also proposes a cost-based 2002 retained generation revenue requirement for the Utility of $2,875 million although it is not clear which costs would be subject to future adjustments.

California Department of Water Resources Purchases

As a result of the Utility's inability to pass through wholesale electricity costs to customers, and the resulting impact on the Utility's financial resources, the Utility's credit rating deteriorated to below investment grade in January 2001. This credit downgrade precluded the Utility from access to capital markets. The Utility had no credit under which it could purchase wholesale electricity on behalf of its customers on a continuing basis. Consequently, generators were only selling to the Utility under emergency action taken by the U.S. Secretary of Energy.

In response to the above, in January 2001, the California Legislature and the Governor of California authorized the DWR to begin purchasing wholesale electric energy on behalf of the Utility's retail customers. On February 1, 2001, the Governor signed into law California AB 1X authorizing the DWR to purchase power to meet the Utility's net open position (the amount of power needed by retail electric customers that cannot be met by utility-owned generation or power under contract to the Utility). The DWR initially purchased energy on the spot market until it was able to enter into contracts for the supply of electricity. In addition to certain contracts that it has subsequently entered into, the DWR continues to purchase power on the spot market at prevailing market prices.

On March 27, 2001, the CPUC issued a decision ordering the Utility and the other California investor-owned utilities to pay the DWR a per-kWh price for the power purchased by the DWR for the Utility's customers. The CPUC determined that the company-wide average generation-related rate was approximately $0.095 per kWh (including the January 2001 $0.010 per kWh and the March 2001 average $0.030 per kWh increases). The Utility, acting as an agent for the DWR with respect to the collection of the portion of the Utility's retail rates that must be paid to the DWR, does not include these amounts (pass-through revenues) in its Consolidated Statements of

Operations (see further discussion below). Total pass-through revenues recorded by the Utility for the year ended December 31, 2001, were $2,173 million.

Initially, the DWR indicated that it intended to buy power only at "reasonable prices" to meet the Utility's net open position, leaving the ISO to purchase the remainder in order to avoid blackouts. The ISO billed the Utility for its costs to purchase power to cover the amount of the Utility's net open position not covered by the DWR. The Utility does not believe it is responsible to pay for the ISO's purchases. The Utility has accrued, but not paid, these ISO amounts up through April 6, 2001 (see "ISO Purchases" below).

On February 21, 2002, the CPUC approved a decision establishing a total statewide revenue requirement for the DWR for the two-year period ending December 31, 2002 of $9 billion. On the same day, the CPUC also approved a decision adopting a rate agreement between the DWR and the CPUC that will allow the DWR to collect bond charges from ratepayers to make principal and interest payments on its anticipated bond proceeds.

The CPUC's revenue requirement decision allocates the total revenue requirements among the customers of the three California investor-owned utilities based on an adopted allocation methodology. Specifically, the decision allocates $4.5 billion to the customers of the Utility for the period from January 2001 through December 2002. Based on this decision, the Utility estimates that its total DWR pass-through amount for 2001 is between $2.6 billion and $2.7 billion. The total revenue requirement as well as the allocation to the Utility is subject to true-up adjustments (true-up) based on the actual amount of power purchased by the DWR for the Utility during the 2001-2002 period. The Utility cannot predict the extent of these future true-ups.

For the year ended December 31, 2001, the Utility has accrued approximately $2.2 billion for pass-through DWR revenues. The decision requires the Utility to remit to the DWR, over a six-month period, the shortfall between the amounts prescribed in the decision and the amounts previously remitted to the DWR from January 17, 2001, through March 15, 2002.

The Utility has accrued approximately $900 million as payable to the ISO for energy that the Utility believes is included in the DWR revenue requirement. However, the amount due to the DWR for the energy may be significantly lower than the amount recorded as payable to the ISO. Because the Utility believes that the combination of these DWR and ISO accruals are more than sufficient to satisfy the Utility's ultimate obligation for energy delivered by the ISO and the DWR, the Utility does not believe the decision has a material adverse impact on 2001 earnings. As discussed in more detail in the "ISO Purchases" section below, in November 2001, the FERC ordered the ISO to invoice the DWR for all ISO transactions entered into on behalf of the Utility. In December 2001, the DWR filed an application for rehearing of this order.

Under the DWR revenue requirement decision, for each kWh of DWR energy delivered and billed subsequent to March 15, 2002, the Utility is required to pass through to the DWR $0.093 cents. The decision also directs the Utility to establish its own interest-bearing balancing account to track recovery of its utility retained generation (URG) revenue requirement net of DWR remittances.

ISO Purchases

As previously stated, despite the Utility's failure to meet the ISO's creditworthiness standards, the ISO billed the Utility for its costs to purchase power to cover the Utility's net open position not covered by the DWR. On February 14, 2001, the FERC ordered that the ISO could only buy power on behalf of creditworthy entities. The FERC order also stated that the ISO could continue to schedule power for the Utility as long as it comes from the Utility's own generation units and is routed over its own transmission lines. Despite the FERC orders, the ISO continued to bill the Utility for the ISO's wholesale electricity costs.

On April 6, 2001, the FERC issued a further order directing the ISO to implement its prior order, and clarifying that its prior order applies to all third-party transactions whether scheduled or not. In light of the FERC's April 6, 2001, order, the Utility has not recorded any such estimated ISO charges after April 6, 2001, except for the ISO's grid management charge. However, the Utility has accrued the full amount of the ISO's previous charges of approximately $1 billion for the purchases from the period of January 17, 2001 through April 6, 2001, in the accompanying financial statements. The Utility believes that $900 million of this $1 billion is included in the DWR revenue requirement (see California Department of Water Resources Purchases above). On June 13, 2001, the FERC denied the ISO's request for rehearing of its April 6, 2001 order. The Utility believes it is not responsible for these costs since it has not met the creditworthiness standards under the ISO tariff since early January 2001.

Furthermore, on June 26, 2001, the Bankruptcy Court issued a preliminary injunction prohibiting the ISO from charging the Utility for the ISO's wholesale power purchases made in violation of bankruptcy law, the ISO's tariff, and the FERC's February 14 and April 6, 2001, orders. In issuing the injunction, the Bankruptcy Court noted that the FERC orders permit the ISO to schedule transactions that involve either a creditworthy buyer or a creditworthy counterparty, although the Court noted the existence of unresolved issues regarding how to ensure these creditworthiness requirements for real-time transactions and emergency dispatch orders issued by the ISO to power sellers.

On November 7, 2001, the FERC issued another order enforcing the creditworthiness requirements of the ISO tariff and rejecting an amendment proposed by the ISO. The order directs the ISO to (1) enforce its billing and settlement provisions under the ISO tariff, (2) invoice the DWR for all ISO transactions it entered into on behalf of the Utility within 15 days from the date of the order, with a schedule for payment of overdue amounts within three months, and (3) reinstate the billing and settlement provisions under the tariff.

Subsequently, the ISO has issued invoices to the DWR for the amounts in dispute. The DWR is in the process of paying substantially all such invoices for the period from January 17, 2001, forward. On December 7, 2001, the DWR filed an application for rehearing of the FERC November 7, 2001, order, alleging, among other things, that the FERC order was illegal and unconstitutional because it restricted the DWR's unilateral discretion to determine the prices it would pay for the third party power under the ISO invoices. If the FERC upholds its previous ruling that the DWR, not the Utility, is responsible for amounts billed by the ISO to the DWR for the period from January 17, 2001, through April 6, 2001, the Utility will reverse the $1 billion accrued during 2001. However, if the Utility reverses the ISO accrual, it would need to record an accrual for its obligation to the DWR for such energy purchases. The Utility expects that this DWR accrual would not exceed the ISO reversal. See above discussion in California Department of Water Resources Purchases.

A proceeding is also pending before the FERC to consider potential refunds for wholesale prices paid to power sellers for purchases made in the ISO and PX spot markets between October 2, 2000, and June 20, 2001.

Statutory End of the Transition Period

The statutory end of the transition period is March 31, 2002. In September 2001, California Senate Bill (SB) X2 was passed which prohibits the CPUC from raising rates for residential and small commercial customers solely as a result of the statutory end of the rate freeze. In conjunction with the end of the transition period, the Utility will discontinue deferring generation-related costs associated with its 10 percent rate reduction provided to certain customers. During the transition period, the Utility provided the 10 percent rate reduction by financing a portion of its generation-related costs with Rate Reduction Bonds (see Note 10 for a description of the Rate Reduction Bonds). In accordance with AB 1890, these financed generation-related transition costs were deferred to the Rate Reduction Bond regulatory asset. The Rate Reduction Bond regulatory asset will be recovered after the end of the transition period through fixed transition revenues. The Utility deferred $458 million during 2001. In 2001, this deferral reduced generation-related costs and contributed to the excess of generation-related revenues over generation-related costs. Also, in the first quarter of 2002, the Utility will begin amortizing its Rate Reduction Bond regulatory asset. This amortization will be approximately $290 million per year and will be offset against fixed transition revenues. In 2001, fixed transition revenues were included in the generation component of electric rates and contributed to the excess of generation-related revenues over generation-related costs.

Cost of Electric Energy

The cost of electric energy for the Utility, reflected in the Utility's Consolidated Statements of Operations, comprises the cost of fuel for electric generation and QF purchases, the cost of PX purchases, and ancillary services charged by the ISO, net of sales to the PX, are as follows:

	Year ended December 31,		
(in millions)	2001	2000	1999
Cost of fuel resources at market prices	$2,863	$ 9,512	$3,233
Proceeds from sales to the PX	(89)	(2,771)	(822)
Total Utility cost of electric energy	$2,774	$ 6,741	$2,411

Note 4: Price Risk Management

PG&E Corporation's net gain (loss) on trading activities, recognized on a fair value basis, were as follows:

(in millions)	Year ended December 31, 2001	2000	1999
Trading activities:			
Unrealized gain (loss), net	$(120)	$ 31	$95
Realized gain (loss), net	296	174	(61)
Total	$ 176	$205	$34

PG&E Corporation's and the Utility's ineffective portion of changes in fair values of cash flow hedges are immaterial for the year ended December 31, 2001. PG&E Corporation's and the Utility's estimated net derivative gains or losses included in accumulated other comprehensive income (loss) at December 31, 2001, that are expected to be reclassified into earnings within the next 12 months are net losses of $3 million and $14,000, respectively. The actual amounts reclassified from accumulated other comprehensive loss to earnings can differ as a result of market price changes.

The schedule below summarizes the activities affecting accumulated other comprehensive income (loss) net of tax, from derivative instruments for the year ended December 31, 2001:

(in millions)	PG&E Corporation	Utility
Beginning derivative gains (losses) included in accumulated other comprehensive income (loss) at January 1, 2001	$(243)	$ 90
Net gain (loss) of current period hedging transactions and price changes	237	(5)
Net reclassification to earnings	42	(85)
Ending derivative gains included in accumulated other comprehensive loss at December 31, 2001	36	—
Foreign currency translation adjustment	(5)	(2)
Other	(1)	—
Ending accumulated other comprehensive income (loss) at December 31, 2001	$ 30	$ (2)

Interest Rate Swaps

At December 31, 2001, and 2000, PG&E NEG had entered into interest rate swap agreements with aggregate notional amounts of $1.6 billion and $1.7 billion, respectively, to manage interest rate exposure on construction and term loan debt and certain lease payments. These agreements have expiration dates through 2014. With respect to certain interest rate swap agreements entered into by PG&E NEG on behalf of the lessor of certain projects, the terms of reimbursement agreements permit PG&E NEG to pass through swap payments and receipts to the lessor during the construction phase of the projects.

Credit Risk

Credit risk is the risk of loss that PG&E Corporation and the Utility would incur if counterparties fail to perform their contractual obligations. PG&E Corporation and the Utility primarily conduct business with customers in the energy industry, such as investor-owned and municipal utilities, energy trading companies, financial institutions, and oil and gas production companies, located in the United States and Canada. This concentration of counterparties may impact PG&E Corporation's and the Utility's overall exposure to credit risk in that its counterparties may be similarly affected by changes in economic, regulatory, or other conditions. PG&E Corporation and the Utility mitigate potential credit losses in accordance with established credit approval practices and limits by dealing primarily with creditworthy counterparties (counterparties considered investment grade or higher). PG&E Corporation and the Utility review credit exposure in relation to specified counterparty limits daily and to the maximum extent possible, require that all derivative contracts take the form of a master agreement which contain credit support provisions that require the counterparty to post security 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.

PG&E Corporation and the Utility calculate gross credit exposure as the current mark-to-market value (what would be lost if the counterparty defaulted today) plus any outstanding net receivables, prior to the application of credit collateral. In the past year, PG&E Corporation's and the Utility's credit risk has increased partially due to credit rating downgrades of some of the counterparties in the energy industry to below investment grade. No single counterparty represents greater than 10 percent of PG&E Corporation's total gross credit exposure at December 31, 2001.

The fair value of claims against counterparties that are in a net asset position, with the exception of written options and exchange-traded futures (the exchange guarantees that every contract is properly settled on a daily basis) as of December 31, 2001, amount to the following:

(in millions)	Gross Exposure*	Credit Collateral**	Net Exposure**
PG&E NEG	$ 932	$ 80	$852
Utility	271	127	144
PG&E Corporation	$1,203	$207	$996

* Gross credit exposure equals mark-to-market value plus net (payables) receivables where netting is allowed. The Utility gross exposure includes wholesale activity only. Retail activity and payables prior to the Utility's bankruptcy filing are not included.

** Net exposure is the gross exposure minus credit collateral (cash deposits and letters of credit). Amounts are not adjusted for probability of default.

The majority of counterparties in which PG&E Corporation and the Utility are exposed are considered to be of investment grade, determined using publicly available information including an S&P rating of at least BBB-. $296 million or 25 percent of PG&E Corporation's gross credit exposure, and $59 million or 22 percent of the Utility's gross credit exposure is below investment grade. PG&E Corporation's regional concentration of credit exposure is to counterparties that primarily do business through the western United States (30 percent) and also to counterparties that do business primarily throughout the entire United States (51 percent). The Utility has a regional concentration of credit exposure to counterparties that primarily conduct business throughout the entire United States (93 percent).

During 2001, PG&E Corporation and the Utility had transacted a significant volume of business with certain subsidiaries of Enron. Enron filed for bankruptcy protection on December 2, 2001. PG&E Corporation's subsidiaries, PG&E NEG and the Utility, have separate contractual relationships with Enron. At December 31, 2001 the Utility was in a net payable position with Enron. The Utility believes that it has the right to offset existing payable and receivable balances with Enron. Accordingly, the Utility recorded no charge against earnings related to Enron.

On December 3, 2001, PG&E ET terminated its contracts with Enron. During the fourth quarter of 2001, PG&E NEG recorded pre-tax charges of $48 million and $12 million (for a total of $60 million) related to trading and non-trading activities, respectively. These charges reflect the write-off through earnings of net price risk management assets related to Enron after application of collateral held and accounts payable. Included as part of the non-trading charge to earnings was the write-off of a net price risk management asset of $18 million related to certain cash flow hedge contracts. As required by SFAS No. 133, the offsetting balance previously recorded in OCI was retained on the balance sheet at its fair value of $18 million as of December 3, 2001. This amount in OCI will be reclassified to income during future periods in which original hedged items will impact earnings (through 2006).

PG&E NEG also held other cash flow hedge contracts with Enron that were in a net gain position of $39 million as of December 3, 2001. The write-off of the net price risk management assets related to these contracts through earnings was offset entirely by the reclassification of the related OCI balances into earnings. This reclassification of OCI into earnings was made in accordance with SFAS No. 133 for hedges for which it was deemed probable that the original hedged forecasted transactions will not occur. The write-offs related to these contracts had no net effect on earnings.

Other than discussed above, PG&E Corporation experienced minimal operational issues related to the Enron bankruptcy and energy trading markets did not experience any significant or sustained decline in liquidity.

Note 5: Fair Value of Financial Instruments

PG&E Corporation used 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, short-term borrowings, current portion of long-term debt, current portion of Rate Reduction Bonds, and accounts payable, approximate their carrying values as of December 31, 2001, and 2000.
- The fair values of long-term receivables and liabilities are estimated using discounted cash flows analysis, based on PG&E Corporation's current incremental borrowing rate. The fair value of most of the Utility's debt is determined using quoted market prices, but the fair value of a small portion of the Utility's debt is determined using the present value of future cash flows.
- The fair values of nuclear decommissioning funds, Rate Reduction Bonds, the Utility preferred stock with mandatory redemption provisions, and utility obligated mandatorily redeemable preferred securities of trust holding solely Utility subordinated debentures are determined based on quoted market prices.
- The fair values of interest rate swap agreements are estimated by calculating the present value of the difference between the total fixed payments of the interest rate swap agreements and the total floating payments using the appropriate current market interest rates. Before PG&E Corporation adopted SFAS No. 133 on January 1, 2001, interest rate swaps were not carried on the balance sheet. The fair value of interest rate swaps at December 31, 2000, was a $74 million liability. Beginning January 1, 2001, PG&E Corporation has accounted for its interest rate swaps as derivatives under SFAS No. 133. These contracts are carried at fair value as a component of price risk management assets and liabilities on the accompanying Consolidated Balance Sheets at December 31, 2001.

The carrying amount and fair value of PG&E Corporation's and the Utility's financial instruments are as follows:

	At December 31,			
	2001		2000	
(in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term receivables:				
PG&E NEG	$ 536	$ 467	$ 611	$ 526
Nuclear decommissioning funds (Note 12):				
Utility	1,337	1,337	1,328	1,328
Long-term debt (Note 9):				
PG&E Corporation	1,000	1,000	—	—
Utility	5,153	4,975	5,716	5,505
PG&E NEG	3,422	3,516	2,225	2,275
Rate reduction bonds (Note 10):				
Utility	1,740	1,811	2,030	2,044
Utility preferred stock with mandatory redemption provisions (Note 8):	137	109	137	98
Utility obligated mandatorily redeemable preferred securities of trust holding solely Utility subordinated debentures (Note 8):	300	246	300	180

Note 6: Acquisitions and Disposals

In December 1999, PG&E Corporation's Board of Directors approved a plan to dispose of PG&E Energy Services (PG&E ES), a wholly owned subsidiary, through a sale. The disposal has been accounted for as a discontinued operation, and PG&E Corporation's investment in PG&E ES was written down to its then estimated net realizable value. In addition, PG&E Corporation provided a reserve for anticipated losses through the anticipated date of sale. The total provision for discontinued operations was $58 million, net of income taxes of $36 million, at December 31, 1999. Of this amount, $33 million (net of taxes) was allocated toward operating losses for the period leading up to the intended disposal date. In 2000, $31 million (net of taxes) of actual operating losses was charged against this reserve. During the second quarter of 2000, PG&E NEG finalized the transactions related to the disposal of the energy commodity portion of PG&E ES for $20 million, plus net working capital of approximately $65 million, for a total of $85 million. In addition, the sale of the value-added services business and various other assets was completed on July 21, 2000, for total consideration of $18 million. For the year ended December 31, 2000, an additional estimated loss of $40 million (or $0.11 per share), net of income tax of $36 million, was recorded, as actual losses in connection with the disposition exceeding those originally estimated. The PG&E ES business segment generated net losses from operations of $40 million (or $0.11 per share) for the year ended December 31, 1999.

On January 27, 2000, PG&E Corporation signed a definitive agreement with El Paso Field Services Company (El Paso) providing for the sale to El Paso, a subsidiary of El Paso Energy Corporation, of the stock of PG&E Gas Transmission, Texas Corporation, PG&E Gas Transmission Teco, Inc., and their subsidiaries (collectively, PG&E GTT). PG&E GTT assets consist of 8,500 miles of natural gas and natural gas liquids pipeline, nine natural gas processing plants, and natural gas storage facilities, all located in Texas. Given the terms of the sales agreement, in 1999 PG&E Corporation recognized a charge against pre-tax earnings of $1.3 billion to reflect PG&E GTT's assets at their fair value. The composition of the pre-tax charge is as follows: (1) an $819 million write-down of net property, plant and equipment, (2) the elimination of the unamortized portion of goodwill in the amount of $446 million, and (3) an accrual of $10 million representing selling costs.

On December 22, 2000, after receipt of governmental approvals, PG&E Corporation completed the stock sale. The total consideration received was $456 million, less $150 million used to retire the PG&E GTT short-term debt, and the assumption by El Paso of PG&E GTT long-term debt having a book value of $564 million. The final sale price was subject to adjustment for a true-up of working capital.

The following table reflects PG&E GTT's pipeline related results of operations included in PG&E Corporation's Consolidated Statements of Operations:

(in millions)	Year ended December 31, 2000	1999
Revenue	$873	$ 1,753
Operating expenses	869	3,058
Operating income (loss)	4	(1,305)
Interest expense and other, net	(36)	7
Sales price true-up	20	—
Loss before income taxes	(12)	(1,298)
Income tax benefit	(32)	(390)
Net income (loss)	$ 20	$ (908)

On September 28, 2000, PG&E NEG purchased for $311 million Attala Generating Company LLC (Attala), which owns a gas-fired power plant that was under construction. Under the purchase agreement, PG&E NEG prepaid the estimated remaining construction costs, which were being managed by the seller. The project, which was approximately 82 percent complete as of December 31, 2000, began commercial service in June 2001. In connection with the acquisition, PG&E NEG also assumed industrial revenue bonds in the amount of $159 million. At December 31, 2001, the seller had paid off the bond.

On July 10, 2001, PG&E NEG sold certain development assets resulting in a pre-tax gain of $23 million.

On September 17 and 28, 2001, PG&E NEG purchased Mountain View Power Partners, LLC, and Mountain View Power Partners II, LLC, respectively. These companies own 44- and 22-megawatt wind energy projects, respectively, near Palm Springs, California. PG&E NEG has contracted with a third party for the operation and maintenance of the wind units and will sell the entire output of the two wind projects under a long-term contract. Total consideration for these two companies was $92 million.

Note 7: Common Stock

PG&E Corporation

PG&E Corporation has authorized 800 million shares of no-par common stock, of which 388 million and 387 million shares were issued and outstanding as of December 31, 2001, and 2000, respectively.

During the years ended December 31, 2001, and 2000, PG&E Corporation repurchased $0.5 million and $2 million of its common stock, respectively. The repurchases were made to satisfy obligations under the Dividend Reinvestment Plan. As of December 31, 2000, a subsidiary of PG&E Corporation had repurchased 23.8 million shares at a cost of $690 million, accounted for as treasury stock and reflected as Stock Held by Subsidiary on the Consolidated Balance Sheets.

On March 2, 2001, PG&E Corporation paid its suspended fourth quarter 2000 stock dividend of $0.30 per common share, declared by the Board of Directors on October 18, 2000, to shareholders of record as of December 15, 2000.

Utility

PG&E Corporation and a subsidiary of the Utility hold all of the Utility's outstanding common stock. The Utility has authorized 800 million shares of $5 par value common stock, of which 327 million shares were issued and outstanding as of December 31, 2001, and 2000.

In April 2000, a subsidiary of the Utility, PG&E Holdings LLC, repurchased from PG&E Corporation 11.9 million shares of the Utility's common stock at a cost of $275 million. At December 31, 2001 and 2000, repurchased common stock totaled $475 million (19.5 million shares) and is included as a reduction from stockholders' equity on the Utility's Consolidated Balance Sheets.

The CPUC requires the Utility to maintain its CPUC-authorized capital structure, potentially limiting the amount of dividends that the Utility may pay PG&E Corporation. On January 10, 2001, the Utility suspended the payment of its fourth quarter 2000 common stock dividend of $110 million, declared in October 2000, to PG&E Corporation and PG&E Holdings LLC. The Utility has suspended payment of its common and preferred stock dividends. Dividends on preferred stock are cumulative. Until cumulative dividends on preferred stock are paid, the Utility may not pay any dividends on common stock.

Note 8: Preferred Stock and Obligated Mandatorily Redeemable Preferred Securities of Trust Holding Solely Utility Subordinated Debentures

Shareholder Rights Plan of PG&E Corporation

On December 20, 2000, the Board of Directors of PG&E Corporation declared a distribution of preferred stock purchase rights (the Rights) at a rate of one Right for each outstanding share of PG&E Corporation common stock. The Rights apply to outstanding shares of PG&E Corporation common stock held as of the close of business on January 2, 2001, and for each share of common stock issued by PG&E Corporation thereafter and before the "distribution date," as described below. Each Right entitles the registered holder, in certain circumstances, to purchase from PG&E Corporation one one-hundredth of a share (a Unit) of PG&E Corporation's Series A Preferred Stock, par value $100 per share, at an initially fixed purchase price of $95 per Unit, subject to adjustment. Effective December 22, 2000, the PG&E Corporation Dividend Reinvestment Plan was modified to note these changes.

The Rights are not exercisable until the distribution date and will expire December 22, 2010, unless redeemed earlier by the PG&E Corporation Board of Directors. The distribution date will occur upon the earlier of (1) 10 days following a public announcement that a person or group (other than the PG&E Corporation, any of its subsidiaries, or its employee benefit plans) has acquired or obtained the right to acquire beneficial ownership of 15 percent or more of the then-outstanding shares of PG&E Corporation common stock and (2) 10 business days (or later, as determined by the Board of Directors) following the commencement of a tender offer or exchange offer that would result in a person or group owning 15 percent or more of the then-outstanding shares of PG&E Corporation common stock. After the distribution date, certain triggering events will enable the holder of each Right (other than a potential acquirer) to purchase Units of Series A Preferred Stock having twice the market value of the initially fixed exercise price, i.e., at a 50 percent discount. Until a Right is exercised, the holder shall have no rights as a shareholder of PG&E Corporation, including without limitation the right to vote or to receive dividends.

A total of 5,000,000 shares of preferred stock will be reserved for issuance upon exercise of the Rights. The Units of preferred stock that may be acquired upon exercise of the Rights will be non-redeemable and subordinate to any other shares of preferred stock that may be issued by PG&E Corporation. Each Unit of preferred stock will have a minimum preferential quarterly dividend rate of $0.01 per Unit but will, in any event, be entitled to a dividend equal to the per share dividend declared on the common stock. In the event of liquidation, the holder of a Unit will receive a preferred liquidation payment.

The Rights also have certain anti-takeover effects and will cause substantial dilution to a person or group that attempts to acquire PG&E Corporation on terms not approved by PG&E Corporation's Board of Directors, unless the offer is conditioned on a substantial number of Rights being acquired. The Rights should not interfere with any approved merger or other business combination, as the Board of Directors, at its option, may redeem the Rights. Thus, the Rights are intended to encourage persons who may seek to acquire control of PG&E Corporation to initiate such an acquisition through negotiations with PG&E Corporation's Board of Directors. However, the effect of the Rights may be to discourage a third party from making a partial tender offer or otherwise attempting to obtain a substantial equity position in the equity securities of, or seeking to obtain control of, PG&E Corporation. To the extent any potential acquirers are deterred by the Rights, the Rights may have the effect of preserving incumbent management in office.

Preferred Stock of 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, 2001, and 2000, the Utility had issued and outstanding 5,784,825 shares of non-redeemable preferred stock.

At December 31, 2001, and 2000, the Utility had issued and outstanding 5,973,456 shares of redeemable preferred stock. 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. Annual dividends and redemption prices per share at December 31, 2001, range from $1.09 to $1.76 and from $25.75 to $27.25, respectively.

At December 31, 2001, the Utility's redeemable preferred stock with mandatory redemption provisions consisted of 3 million shares of the 6.57 percent series and 2.5 million shares of the 6.30 percent series. The 6.57 percent series and 6.30 percent series may be redeemed at the Utility's option on or after July 31, 2002, and 2004, respectively, at par value plus accumulated and unpaid dividends through the redemption date. These series of preferred stock are subject to mandatory redemption provisions entitling them to sinking funds providing for the retirement of the stock outstanding.

At December 31, 2001, the redemption requirements for the Utility's redeemable preferred stock with mandatory redemption provisions are $4 million per year beginning 2002, and $3 million per year beginning 2004 for the series 6.57 percent and 6.30 percent, respectively.

Holders of the Utility's non-redeemable preferred stock 5.0 percent, 5.5 percent, and 6.0 percent series have rights to annual dividends per share ranging from $1.25 to $1.50.

Due to the California energy crisis, the Utility's Board of Directors did not declare the regular preferred stock dividend for the three-month period ending January 31, 2001 (normally payable on February 15, 2001), April 30, 2001 (normally payable on May 15, 2001), July 31, 2001 (normally payable August 15, 2001), and October 31, 2001 (normally payable November 15, 2001).

Dividends on all Utility preferred stock are cumulative. All shares of preferred stock have voting rights and equal preference in dividend and liquidation rights. Accumulated and unpaid preferred stock dividends amounted to $25 million as of December 31, 2001. 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. Until cumulative dividends on its preferred stock are paid, the Utility may not pay any dividends on its common stock, nor may the Utility repurchase any of its common stock.

Preferred Stock of PG&E NEG

Preferred stock of PG&E NEG consists of $58 million of preferred stock issued by a subsidiary of PG&E Gen. The preferred stock, with $100 par value, has a stated non-cumulative quarterly dividend of $3.35 per share, and is redeemable when there is an excess of available cash. There were 549,594 shares of preferred stock outstanding at December 31, 2001, and 2000.

Utility Obligated Mandatorily Redeemable Preferred Securities of Trust Holding Solely Utility Subordinated Debentures

On November 28, 1995, PG&E Capital I (Trust), a wholly owned subsidiary of the Utility, issued 12 million shares of 7.90 percent Cumulative Quarterly Income Preferred Securities (QUIPS), with an aggregate liquidation value of $300 million. Concurrent with the issuance of the QUIPS, the Trust issued to the Utility 371,135 shares of common securities with an aggregate liquidation value of $9 million. The Trust in turn used the net proceeds from the QUIPS offering and issuance of the common stock securities to purchase 7.90 percent Deferrable Interest Subordinated Debentures (Debentures) due 2025 issued by the Utility with a face value of $309 million.

On March 16, 2001, the Utility deferred quarterly interest payments on the Utility's Debentures until further notice in accordance with the indenture. The corresponding quarterly payments on the 7.90 percent QUIPS, issued by the Trust, due on April 2, 2001, have been similarly deferred.

Distributions may be deferred up to 20 consecutive quarters under the terms of the indenture. Per the indenture, investors will accumulate interest on the unpaid distributions at the rate of 7.90 percent. Upon liquidation or dissolution of the Utility, holders of these QUIPS would be entitled to the liquidation preference of $25 per share plus all accrued and unpaid dividends thereon to the date of payment.

On April 12, 2001, Bank One, N.A., as successor-in-interest to The First National Bank of Chicago (Property Trustee), gave notice that an event of default exists under the Trust Agreement due to the Utility's filing for Chapter 11 on April 6, 2001 (see Note 2). As a result of the Chapter 11 filing, the Trust Agreement requires the Trust to be liquidated by the Trustees by distributing, after satisfaction of liabilities to creditors of the Trust, the Debentures to the holders of the QUIPS.

On December 13, 2001, the Utility received permission from the Bankruptcy Court to distribute the Debentures of the Utility, and register the Debentures as Cumulative Quarterly Income Deferred Securities (QUIDS). However, the QUIPS will not be converted to QUIDS until such time as the Trustee notifies the holders of the QUIPS of the exchange. The QUIPS are reflected as "Mandatorily Redeemable Preferred Securities of Trust Holding Solely Utility Subordinated Debentures" on the Utility's Consolidated Balance Sheets. The terms and interest payments on the QUIDS correspond to the terms and dividend payments of the QUIPS. The Utility has the right to redeem all or part of the debentures.

Note 9: Long-Term Debt

Long-term debt consisted of the following:

(in millions)	Balance at December 31, 2001	2000
Long-Term Debt:		
PG&E Corporation		
General Electric and Lehman Credit Facility due in 2003, variable	$1,000	$ —
Discount	(96)	—
Total long-term debt, net of current portion	904	—
Utility		
First and refunding mortgage bonds:		
Maturity / Interest Rates		
2002-2005 5.875% to 7.875%	1,214	1,306
2006-2010 6.35% to 6.625%	85	85
2011-2026 5.85% to 8.80%	2,079	2,079
Principal amounts outstanding	3,378	3,470
Unamortized discount net of premium	(26)	(28)
Total mortgage bonds	3,352	3,442
Less: current portion	333	100
Total long-term debt, net of current portion	3,019	3,342
PG&E NEG		
Senior unsecured notes, 7.10%, due 2005	250	250
Senior unsecured notes, 10.375%, due 2011	1,000	—
Senior unsecured debentures, 10.00%, due 2010	—	159
Senior unsecured debentures, 7.80%, due 2025	150	150
Medium-term notes, 6.83% to 6.96%, due 2002-2003	39	39
Term loans, various, 2003-2022	1,798	921
Amount outstanding under credit facilities (see note 11)	160	661
Other long-term debts	25	45
Sub-total	3,422	2,225
Less: current portion	48	17
Total long-term debt, net of current portion	3,374	2,208
Total Long-Term Debt	7,297	5,550
Long-Term Debt Subject to Compromise:		
Utility		
Senior notes, 9.625%, due 2005	680	680
Pollution control loan agreements, variable rates, due 2016-2026	814	1,267
Unsecured medium-term notes, 5.81% to 8.45%, due 2002-2014	287	305
Other Utility long-term debt	20	22
Total Long-Term Debt Subject to Compromise	$1,801	$2,274

PG&E Corporation

On March 1, 2001, PG&E Corporation refinanced its debt obligations with $1 billion in aggregate proceeds from two term loans under a common credit agreement with General Electric Capital Corporation (GECC) and Lehman Commercial Paper Inc. (LCPI), maturing on March 1, 2003. In accordance with the credit agreement, the proceeds, together with other PG&E Corporation cash, were used to pay $501 million in commercial paper (including $457 million of commercial paper on which PG&E Corporation had defaulted), $434 million in borrowings under PG&E Corporation's long-term revolving credit facility, and $109 million to PG&E Corporation shareholders of record as of December 15, 2000, in satisfaction of the defaulted fourth quarter 2000 common stock dividend. Further, approximately $99 million was used to pre-pay the first year's interest under the credit agreement and to pay transaction expenses associated with the debt restructuring.

In November 2001, and March 2002, PG&E Corporation signed agreements to amend its $1 billion aggregate term loan credit facility. The original credit facility, which was entered into with GECC and LCPI on March 1, 2001, permitted PG&E Corporation to extend the term of the credit facility, which would otherwise expire on March 1, 2003, for an additional year. The amendments give PG&E Corporation the option for two additional one-year periods so that the termination date could be extended to March 2, 2006, although the loan would be due and payable if a spin-off of the shares of PG&E NEG were to occur. As a condition to exercise each of the new one-year extensions, PG&E Corporation is required to have reduced the loan balance by $308 million by June 3, 2002, pay a fee of three percent of the then-outstanding balance of the loans, and also issue to the lenders additional options equal to approximately 1 percent of the common stock of PG&E NEG, for each extension. Under the original credit agreement, $692 million was eligible for the one-year extension.

The loans prohibit PG&E Corporation from declaring dividends, making other distributions to shareholders, or incurring additional indebtedness until the loans have been repaid, although PG&E Corporation could incur unsecured indebtedness provided it meets certain requirements. The loan also prohibits PG&E NEG from making distributions to PG&E Corporation and restricts certain other intercompany transactions.

Further, as required by the credit agreement, PG&E NEG has granted to affiliates of the lenders options that entitle these affiliates to purchase up to 5 percent of the shares of the PG&E NEG at an exercise price of $1.00 based on the following schedule:

	Percentages of Shares Subject to PG&E NEG Options
Loans outstanding for:	
Less than 18 months	2.5%
18 months to three years	3.0%
Three to four years	4.0%
Four to five years	5.0%

The option becomes exercisable on the date of full repayment or earlier, if an initial public offering (IPO) of the shares of the PG&E NEG were to occur. PG&E NEG has the right to call the option in cash at a purchase price equal to the fair market value of the underlying shares, which right is exercisable at any time following the repayment of the loans. If an IPO has not occurred, the holders of the option have the right to require PG&E NEG or PG&E Corporation to repurchase the option at a purchase price equal to the fair market value of the underlying shares, which right is exercisable at any time after the earlier of full repayment of the loans or 45 days after the maturity of the loans. The fair value of the options granted are recorded as a debt issuance cost and amortized over the expected life of the loans. After the initial recording, the options are marked to market through an increase or decrease in earnings.

Under the credit agreement, PG&E NEG is permitted to make investments, incur indebtedness, sell assets, and operate its businesses pursuant to its business plan. Mandatory repayment of the loans will be required from the net after-tax proceeds received by PG&E NEG or any subsidiary of PG&E NEG from (1) the issuance of indebtedness, (2) the issuance or sale of any equity (except for cash proceeds from an IPO), (3) asset sales, and (4) casualty insurance, condemnation awards, or other recoveries. However, if such proceeds are retained as cash, used to pay indebtedness, or reinvested in PG&E NEG's businesses, mandatory repayment will not be required.

The credit agreement contains certain covenants, including requirements that (1) the PG&E NEG's unsecured long-term debt have a credit rating of at least BBB- by S&P or Baa3 by Moody's, (2) the ratio of fair market value of PG&E NEG to the aggregate amount of principal then outstanding under the loans is not less than two to one, and (3) PG&E Corporation maintain a cash or cash equivalent reserve of at least 15 percent of the total principal amount of the loans outstanding until March 2, 2004, and 10 percent thereafter, unless PG&E Corporation prepays the interest attributable to the then applicable extension period. A breach of covenants entitles the lenders to declare the loans to be due and payable. In addition, failure of PG&E NEG to maintain at least a 1.25:1 ratio of fair market value to loan balance constitutes an immediate event of default and results in acceleration of the loan.

Utility

Due to the Chapter 11 proceeding (see Note 2), certain pre-petition long-term debt has been reclassified to the caption Subject to Compromise in the above table and on the Consolidated Balance Sheets. Amounts listed in 2000 Long-Term Debt Subject to Compromise were reclassified from their current and long-term status in the prior year for comparison purposes in the above table. These instruments did not become subject to compromise until the bankruptcy filing.

First and Refunding Mortgage Bonds

First and refunding mortgage bonds are issued in series and bear annual interest rates ranging from 5.85 percent to 8.80 percent. All real properties and substantially all personal properties of the Utility are subject to the lien of the mortgage, and the Utility is required to make semi-annual sinking fund payments for the retirement of the bonds. Prior to the bankruptcy, additional bonds could have been issued subject to CPUC approval, up to a maximum total amount outstanding of $10 billion, assuming compliance with indenture covenants for earnings coverage and available property balances as security. While the Utility continues business as a debtor-in-possession, the mortgage bonds are stayed. However, the Bankruptcy Court has approved the payment of interest in accordance with the terms of the bonds. On February 27, 2002, the Bankruptcy Court approved the Utility's payment of $333 million of mortgage bonds maturing in March 2002.

Included in the total of outstanding bonds at December 31, 2001, and 2000, are $345 million of bonds held in trust for the California Pollution Control Financing Authority (CPCFA) with interest rates ranging from 5.85 percent to 6.625 percent and maturity dates ranging from 2009 to 2023. In addition to these bonds, the Utility holds long-term pollution control loan agreements with the CPCFA as described below.

Senior Notes

In November 2000, the Utility issued $680 million of five-year senior notes with an interest rate of 7.375 percent. The Utility used the net proceeds to repay short-term borrowings incurred to finance scheduled payments due to the PX for August power purchases from the PX and for other general corporate purposes. These notes contained interest rate adjustments dependent upon the Utility's unsecured debt ratings.

As a result of the credit rating downgrades, there was an interest rate adjustment of 1.75 percent on the $680 million senior notes. In addition, there was an interest premium penalty of 0.5 percent imposed on the senior notes due to the Utility's inability to make a public offering on April 30, 2001. Accordingly, the rate increased to 9.625 percent from 7.375 percent on May 1, 2001. However, the 9.625 percent rate was made effective as of November 1, 2001. In 2001, the Utility's bankruptcy filing and non-payment on the Senior Notes were events of default. Accordingly, the amount outstanding as of December 31, 2001, has been classified as Liabilities Subject to Compromise.

Pollution Control Loan Agreements

Pollution control loan agreements from the CPCFA totaled $814 million and $1,267 million for December 31, 2001 and 2000, respectively. Interest rates on the majority of the loans are variable. For 2001, the variable interest rates ranged from 1.61 percent to 6.34 percent. These loans are subject to redemption by the holder under certain circumstances. These loans were secured primarily by irrevocable letters of credit (LOC) which mature in 2002 through 2003. In December 2000, two of these loans totaling $81 million were reacquired by the Utility. On March 1, 2001, a $200 million loan was converted to a fixed rate obligation with an interest rate of 5.35 percent.

Due to the bankruptcy filing, the Utility was unable to reimburse the banks for interest drawings on their letters of credit. In April and May 2001, four loans totaling $454 million were accelerated. These redemptions were funded by the letter of credit banks resulting in like obligations from the Utility to the banks. Accordingly, amounts outstanding at December 31, 2001 and 2000, under the pollution control agreements were classified as Liabilities Subject to Compromise in the accompanying financial statements.

Medium-Term Notes

The Utility has outstanding $287 million of medium-term notes due from 2001 to 2014 with interest rates ranging from 5.81 percent to 8.45 percent, which are also in default. Accordingly, the amount outstanding at December 31, 2001, and 2000, were classified as Liabilities Subject to Compromise in the accompanying financial statements.

PG&E NEG

Long-term debt of PG&E NEG consists of secured and unsecured obligations.

In May 1995, PG&E GTN issued $250 million of 10-year senior unsecured notes and $150 million of senior unsecured debentures. On May 22, 2001, PG&E NEG completed an offering of $1 billion in senior unsecured notes (Senior Notes) and received net proceeds of approximately $972 million after bond debt discount and note issuance costs. PG&E NEG used a portion of the net proceeds and intends to use the balance of the net proceeds to pay down existing revolving debt, fund investment in generating facilities and pipeline assets, working capital requirements and other general corporate requirements. These Senior Notes bear interest at 10.375 percent per annum and mature on May 16, 2011.

In May 2001, PG&E NEG established a revolving credit facility of up to $280 million to fund turbine payments and equipment purchases associated with its generation facilities. This facility is due to be fully repaid on December 31, 2003. As of December 31, 2001, $221 million was outstanding at a weighted average interest rate of approximately 3.3 percent.

In September 2001, PG&E NEG secured a $69.4 million non-recourse 5-year project financing loan for the construction of the Plains End generating project in Colorado. The facility expires upon the earlier of five years after commercial operation has been declared on September 2007. As of December 31, 2001, there was $23 million outstanding under this financing at an interest rate of approximately 3.2 percent.

In December 2001, PG&E NEG completed a $1.075 billion 5-year non-recourse financing secured by a portfolio of projects. The facility was used to reimburse PG&E NEG and lenders for a portion of construction costs already incurred on these projects and will be used to fund a portion of the balance of construction costs. As of December 31, 2001, there was $449.5 million outstanding under this facility, at an average interest rate of 4.6 percent. This facility provides for borrowings that bear interest at LIBOR plus a credit spread. This facility also requires PG&E NEG to make an equity commitment of $701 million, which it has done, in part, by pledging the portfolio of projects.

In addition, PG&E NEG maintains various revolving credit facilities at subsidiary levels which currently are available to fund capital and liquidity needs. USGenNE maintains a $100 million revolving credit facility which expires in September 2003. $75 million is outstanding under this facility. PG&E GTN maintains a $100 million revolving credit facility that expires in May 2002. $85 million is outstanding under this facility. Outstanding loans on these two facilities are charged LIBOR-based interest rates with an interest rate spread over LIBOR tied to the credit rating of the applicable subsidiary and the amount drawn on the facility. As of December 31, 2001, $160 million is classified as long-term because PG&E NEG has the ability and intent to finance the amounts on a long-term basis.

In August 2001, PG&E NEG arranged a $1.25 billion working capital and letter of credit facility consisting of $500 million with a two-year term and $750 million with a 364-day term maturing in August 2003 and August 2002, respectively, which is used to provide working capital and liquidity support for letters of credit for development and construction expenditures and for other general corporate purposes. Outstanding loans under this facility are charged LIBOR-based interest rates and an interest rate spread over LIBOR tied to PG&E NEG's credit ratings. On December 31, 2001, no amounts were outstanding under the two-year term portion of this facility.

Other long-term debt consists of project financing associated with PG&E Gen facilities, premiums, and other loans. Certain credit agreements of PG&E NEG contain, among other restrictions, customary affirmative covenants, representations and warranties and have cross-default provisions with its other credit agreements. The credit agreements also contain certain negative covenants including restrictions with respect to the following: consolidations, mergers, sales of assets and investments, certain liens on property or assets, incurrence of additional senior indebtedness, making distributions, and certain transactions with affiliates. Certain credit agreements also require that PG&E NEG maintain certain interest coverage and debt ratios.

During 2001 and 2000, two indirect wholly owned subsidiaries of PG&E NEG entered into two lease commitments relating to projects that are under construction, for which they act as the construction agent for the owners. Under these arrangements, a third party owner/lessor is financing the construction of each facility. Upon completion of the construction projects, expected to be in 2002, the lease terms of up to five years will commence. At the conclusion of each of the lease terms, PG&E NEG has the option to extend the leases at fair market value, purchase the projects, or act as remarketing agent for the lessors for sales to third parties. If PG&E NEG elects to remarket the projects, then PG&E NEG would be obligated to the lessors for up to 85 percent of the project costs if the proceeds are deficient to pay the lessor's investors. PG&E NEG has committed to the projects' lenders to contribute up to $609 million through the purchase of the portion of the project loans secured by PG&E NEG guarantees no later than March 31, 2003. The equity infusions could be triggered earlier by a downgrade of PG&E NEG to below investment grade by both S&P and Moody's on the failure to meet certain covenants of either project. As of December 31, 2001, project costs subject to these agreements totaled $1,012 million and total costs for both projects are expected to be approximately $1,148 million. Financing for these projects totaled $1,005 million and $814 million as of December 31, 2001, and 2000, respectively. The trust holding the assets and debt related to these facilities has been consolidated in the accompanying financial statements.

Repayment Schedule

At December 31, 2001, PG&E Corporation's combined aggregate amounts of maturing long-term debt, and sinking fund requirements are reflected in the table below:

Expected maturity date (dollars in millions)	2002	2003	2004	2005	2006	Thereafter	Total
PG&E Corporation	$ —	$1,000	$ —	$ —	$ —	$ —	$1,000
Utility:							
Long-term debt:							
Liabilities not subject to compromise:							
Fixed rate obligations	333	281	310	290	—	2,138	3,352
Average interest rate	7.88%	6.25%	6.25%	5.89%	—%	7.25%	7.02%
Liabilities subject to compromise:							
Fixed rate obligations	134	41	54	696	1	261	1,187
Average interest rate	7.71%	6.38%	7.51%	9.56%	9.45%	5.96%	8.36%
Variable rate obligations	349	265	—	—	—	—	614
Rate reductions bonds	290	290	290	290	290	290	1,740
Average interest rate	6.30%	6.36%	6.42%	6.42%	6.44%	6.48%	6.40%
PG&E NEG:							
Long-term debt:							
Variable rate obligations	14	842	31	41	47	999	1,974
Fixed rate obligations	34	6	—	250	1	1,157	1,448
Average interest rate	5.89%	7.49%	8.28%	8.64%	8.86%	8.94%	8.50%

Note 10: Rate Reduction Bonds

In December 1997, PG&E Funding LLC (LLC), a limited liability corporation wholly owned by and consolidated with the Utility, issued $2.9 billion of Rate Reduction Bonds to the California Infrastructure and Economic Development Bank Special Purpose Trust PG&E-1 (Trust). The terms of the bonds generally mirror the terms of the pass-through certificates issued by the Trust. The proceeds of the Rate Reduction Bonds were used by LLC to purchase from the Utility the right, known as "transition property," to be paid a specified amount from a non-bypassable tariff levied on residential and small commercial customers which was authorized by the CPUC pursuant to state legislation.

On January 4, 2001, S&P lowered the short-term credit rating of LLC to A-3, and on January 5, 2001, Moody's lowered the short-term credit rating of LLC to P-3. As a result, on January 8, 2001, remittances for charges paid by ratepayers for the pass-through certificates issued by the Trust were required to be made on a daily basis, as opposed to once a month, as had previously been required.

The Rate Reduction Bonds have maturities ranging from six months to six years, and bear interest at rates ranging from 6.25 percent to 6.48 percent. The bonds are secured solely by the transition property and there is no recourse to the Utility or PG&E Corporation.

At December 31, 2001, and 2000, $1,740 million and $2,030 million of Rate Reduction Bonds were outstanding, respectively. The principal payments on the Rate Reduction Bonds for the years 2002 through 2006 are $290 million for each year. While LLC is a wholly owned consolidated subsidiary of the Utility, LLC is legally separate from the Utility. The assets of 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.

Note 11: Credit Facilities and Short-Term Borrowings

At December 31, 2001, and 2000, PG&E Corporation had borrowed $3,995 million and $5,191 million, respectively, through short-term borrowings and various credit facilities. At December 31, 2001, and 2000, $160 million and $661 million, respectively, of these borrowings were outstanding balances related to PG&E NEG's credit facilities, which are classified as long-term debt because PG&E NEG has the ability and intent to finance the amounts outstanding on a long-term basis. Due to the Utility's bankruptcy filing (see Note 2), pre-petition credit facilities at December 31, 2001, and 2000, of $938 million and $614 million, respectively, and short-term borrowings of $2,567 million and $2,465 million, respectively, have been classified as Liabilities Subject to Compromise in the table below and on the Consolidated Balance Sheets for 2001. Amounts listed as Credit Facilities and Short-Term Borrowings as of December 31, 2000, were reclassified from their current status in the prior year for comparison purposes in the table below. The weighted average interest rate on the short-term borrowings as of December 31, 2001, and 2000, was 3.78 percent and 7.06 percent, respectively. The weighted average interest rate on the short-term borrowings subject to compromise as of December 31, 2001, and 2000, was 7.53 percent and 7.51 percent, respectively. The weighted average on the 2000 short-term borrowings subject to compromise is presented for comparison purposes. The following table summarizes PG&E Corporation's lines of credit.

Credit Facilities and Short-Term Borrowings (in millions)	December 31, 2001		December 31, 2000	
	Revolving Credit Limits	Outstanding Balance	Revolving Credit Limits	Outstanding Balance
Lines of Credit:				
PG&E Corporation				
5-year Revolving Credit Facility	$ —	$ —	$ 500	$ 185
364-day Revolving Credit Facility	—	—	436	—
PG&E NEG				
Revolving Credit Facilities	1,450	490	1,350	661
Total Facilities	$1,450	490	2,286	846
Short-Term Borrowings:				
PG&E Corporation				
Commercial Paper		—		746
PG&E NEG		—		520
Total Short-Term Borrowings		—		1,266
Less: PG&E NEG revolving credit classified as long-term debt		(160)		(661)
Total Short-Term Borrowings		330		1,451
Credit Facilities Subject to Compromise:				
Utility				
5-year Revolving Credit Facility		938	1,000	614
364-day Revolving Credit Facility		—	850	—
Total Lines of Credit Subject to Compromise		938	$1,850	614
Short-Term Borrowings Subject to Compromise:				
Utility				
Bank Borrowings – Letters of Credit for Accelerated Pollution Control Agreements		454		—
Floating Rate Notes		1,240		1,240
Commercial Paper		873		1,225
Total Short-Term Borrowings Subject to Compromise		2,567		2,465
Total Credit Facilities and Short-Term Borrowings Subject to Compromise		$3,505		$3,079

PG&E Corporation

In March 2001, PG&E Corporation secured $1 billion in aggregate proceeds from two term loans under a common credit agreement with GECC and LCPI in order to pay off its previously defaulted commercial paper and revolving credit obligations. The revolving credit facilities were subsequently cancelled.

Utility

Credit Facility

As of December 31, 2000, the Utility had a $1 billion revolving credit facility which was scheduled to expire in December 2002. In October 2000, the Utility obtained an additional $1 billion credit facility, which was subsequently reduced to $850 million in December 2000. These facilities were used to support the Utility's commercial paper program and other liquidity requirements. On December 15, 2000, due to an uncertain and volatile environment, the Utility suspended the issuance of its Commercial Paper Program. As a result, the Utility began to draw on its five-year revolving credit facility in order to finance its liquidity needs and pay off maturing commercial paper.

On January 16 and 17, 2001, S&P and Moody's, downgraded the Utility's credit ratings to below investment grade. This downgrade resulted in an event of default under the $850 million credit facility, while the Utility's non-payment of commercial paper exceeding $100 million constituted events of default under both the $1 billion and $850 million credit facilities. Consequently, the banks refused any additional borrowing requests, and terminated their outstanding commitments under the Utility's two credit facilities. In 2001, prior to the event of default, the Utility had drawn $324 million on its five-year revolving facility.

Commercial Paper

The total amount of commercial paper outstanding at December 31, 2001, was $873 million. The commercial paper outstanding is in default as of December 31, 2001. In 2001, prior to the bankruptcy, the Utility repaid $352 million of its commercial paper. The weighted average interest rate on the Utility's short-term borrowings as of December 31, 2001 and 2000, was 7.47 percent and 7.50 percent, respectively.

Floating Rate Notes

The Utility issued a total of $1,240 million of 364-day floating rate notes in November 2000, with interest payable quarterly. These notes were not paid on the maturity date of November 30, 2001. Non-payment of the floating rate notes was an event of default, entitling the floating rate note trustee to accelerate the repayment of these notes.

Bank Borrowing – Letters of Credit for Accelerated Pollution Control Bonds

As discussed in Note 9, four pollution control loan agreements were redeemed. These redemptions were funded by the letter of credit banks resulting in similar obligations from the Utility to the banks.

PG&E NEG

In August 2001, PG&E NEG arranged a $1.25 billion working capital and letter of credit facility, consisting of $500 million with a 2-year term, and $750 million with a 364-day term, maturing in August 2003 and August 2002, respectively. PG&E NEG uses this facility to provide working capital and liquidity to its businesses for letters of credit, to fund development, and early phase construction expenditures, and for other general corporate purposes. At December 31, 2001, PG&E NEG had total outstanding balances related to such borrowings of $330 million. In addition, at December 31, 2001, $115 million of letters of credit were outstanding under these facilities.

A $500 million 364-day facility and a $550 million five-year facility were repaid and cancelled on August 23, 2001.

In addition, PG&E GTN, a subsidiary of PG&E NEG, has a $100 million facility which expires in May 2002. PG&E GTN intends to refinance the debt supported by the revolving credit agreement on a long-term basis. At December 31, 2001, the total outstanding balance under this facility was $85 million. USGenNE also has a $100 million credit line to fund capital and liquidity needs. This facility expires in September 2003. At December 31, 2001, the total outstanding balance under this facility was $75 million.

Since PG&E NEG has the ability and intent to refinance certain borrowings, $160 million and $661 million of the facilities (PG&E GTN and USGenNE) are classified as long-term debt as of December 31, 2001 and 2000, respectively. The remaining outstanding balances are classified as short-term borrowings in the Consolidated Balance Sheets.

Certain credit agreements of PG&E NEG contain, among other restrictions, customary affirmative covenants, representations and warranties, and have cross-default provisions with respect to its other credit agreements. The credit agreements also contain certain negative covenants including restrictions on the following: consolidations, mergers, sales of assets and investments, certain liens on property or assets, incurrence of additional senior indebtedness, and certain transactions with affiliates. Certain credit agreements also require that PG&E NEG maintain certain interest coverage and debt ratios.

Note 12: Nuclear Decommissioning

Decommissioning of the Utility's nuclear power facilities is scheduled to begin for ratemaking purposes in 2015 with scheduled completion in 2041. Nuclear decommissioning means the safe removal of nuclear facilities from service and reduction of residual radioactivity to a level that permits termination of the NRC license and release of the property for unrestricted use.

The estimated total obligation for nuclear decommissioning costs, based on a January 2002 site study, is $1.8 billion in 2001 dollars (or $7.8 billion in future dollars). The Utility's future estimate is based upon its 2001 estimated obligation assuming an annual escalation rate of 5.5 percent for decommissioning costs. The Utility plans to fund these costs from independent decommissioning trusts which receive annual contributions discussed further below. The Utility estimates after-tax annual earnings, including realized gains and losses, on the tax-qualified and non-tax-qualified decommissioning funds of 6.34 percent and 5.39 percent, respectively. The decommissioning cost estimates are based on the plant location and cost characteristics for the Utility's nuclear plants. Actual decommissioning costs are expected to vary from this estimate because of changes in assumed dates of decommissioning, regulatory requirements, technology, costs of labor, materials, and equipment. The estimated total obligation is being recognized proportionately over the license term of each facility.

The CPUC has established a Nuclear Decommissioning Cost Triennial Proceeding (Triennial Proceeding) to review, every three years, updated decommissioning cost estimates and to establish the annual trust contributions. The next Triennial Proceeding is scheduled for March 2002, covering the period 2002 through 2004. The monies contributed to the decommissioning trusts, together with existing trust fund balances and projected earnings, including realized gains and losses, are intended to satisfy the estimated future obligation for decommissioning costs.

In April 2001, the IRS approved a new schedule of ruling amount (SRA) that lowered the annual amount collected through rates to $24 million, effective January 1, 1999. For the year ended December 31, 2001, annual nuclear decommissioning trust contributions collected in rates were $24 million and this amount was contributed to the trusts.

At December 31, 2001, the total nuclear decommissioning obligation accrued was $1.3 billion and is included in the Consolidated Balance Sheets classification of accumulated depreciation and decommissioning. Decommissioning costs recovered in rates are placed in external trust funds. These funds, along with accumulated earnings, will be used exclusively for decommissioning and cannot be released from the trusts until authorized by the CPUC. Earnings on the funds accumulated in the external trusts are recorded as a component of depreciation expense. Additionally, the CPUC has authorized the trusts to invest up to a maximum of 50 percent in publicly traded equity securities, of which up to 20 percent may be invested in publicly traded non-U.S. securities. The trusts are in compliance with the investment restrictions authorized by the CPUC.

The following table provides a summary of fair value, based on quoted market prices, of these nuclear decommissioning trust funds:

(in millions)	Maturity Date	Year ended December 31, 2001	2000
U.S. government and agency issues	2002-2031	$ 476	$ 475
Equity securities		706	659
Municipal bonds and other	2002-2034	231	278
Other assets		44	61
Other liabilities		(120)	(145)
Fair value		$1,337	$1,328

The proceeds received from sales of securities were $0.8 billion, $1.4 billion, and $1.7 billion in 2001, 2000, and 1999, respectively. The gross realized gains on sales of securities held as available-for-sale were $71 million, $74 million, and $59 million in 2001, 2000, and 1999, respectively. The gross realized losses on sales of securities held as available-for-sale were $98 million, $64 million, and $60 million in 2001, 2000, and 1999, respectively. The cost of debt and equity securities sold is determined by specific identification.

Under the Nuclear Waste Policy Act of 1982, the U.S. Department of Energy (DOE) is responsible for the permanent storage and disposal of spent nuclear fuel. 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 nuclear power facilities. The DOE's current estimate for an available site to begin accepting physical possession of the spent nuclear fuel is 2010. At the projected level of operation for Diablo Canyon, the Utility's facilities are sufficient to store on-site all spent fuel produced through approximately 2006. It is likely that an interim or permanent DOE storage facility will not be available for Diablo Canyon's spent fuel by 2006. The Utility is examining options for providing additional temporary spent fuel storage at Diablo Canyon or other facilities, pending disposal or storage at a DOE facility.

Note 13: Employee Benefit Plans

Pension and Other Benefits

PG&E Corporation and its subsidiaries provide both qualified and nonqualified noncontributory defined benefit pension plans for their employees, retirees, and non-employee directors (referred to collectively as pension benefits). In addition, PG&E Corporation and its subsidiaries provide contributory defined benefit medical plans for certain retired employees and their eligible dependents and noncontributory defined benefit life insurance plans for certain retired employees (referred to collectively as other benefits). For both pension benefits and other benefit plans, the Utility's plans represent substantially all of the plan assets and the benefit obligation. Therefore, all descriptions and assumptions are based on the Utility's plans. The schedules on the following page aggregate all of PG&E Corporation's plans.

The following schedule reconciles the plans' funded status (the difference between fair value of plan assets and the benefit obligation) to the prepaid or accrued benefit cost recorded on the Consolidated Balance Sheets:

	Pension Benefits		Other Benefits	
(in millions)	2001	2000	2001	2000
Change in benefit obligation				
Benefit obligation at January 1	$(5,405)	$(4,807)	$(1,009)	$ (970)
Service cost for benefits earned	(128)	(119)	(21)	(16)
Interest cost	(420)	(386)	(74)	(72)
Plan amendments	—	(347)	—	—
Actuarial loss	(408)	(33)	(12)	(11)
Divestiture	—	7	—	17
Participants paid benefits	—	—	(20)	(14)
Benefits and expenses paid	274	280	71	57
Benefit obligation at December 31	(6,087)	(5,405)	(1,065)	(1,009)
Change in plan assets				
Fair value of plan assets at January 1	7,808	8,153	1,012	1,091
Actual return on plan assets	(364)	(66)	(70)	(33)
Company contributions	5	3	27	2
Plan participant contribution	—	—	20	14
Divestiture	—	(2)	—	—
Benefits and expenses paid	(274)	(280)	(74)	(62)
Fair value of plan assets at December 31	7,175	7,808	915	1,012
Funded Status				
Plan assets in excess of benefit obligation (plan benefit obligation in excess of assets)	1,088	2,403	(150)	3
Unrecognized prior service cost	358	399	14	15
Unrecognized net gain	(501)	(2,001)	(156)	(348)
Unrecognized net transition obligation	36	50	287	314
Prepaid (accrued) benefit cost	$ 981	$ 851	$ (5)	$ (16)

The Utility's share of plan assets in excess of the benefit obligation for pensions in 2001 and 2000 was $1,103 million and $2,407 million, respectively. The Utility's share of the prepaid benefit cost for pensions in 2001 and 2000 was $994 million and $864 million, respectively.

The plan benefit obligations of the Utility exceeded its share of plan assets for other benefits by $147 million in 2001 while plan assets of the Utility exceeded its share of the benefit obligation for other benefits by $3 million in 2000. The Utility's share of the accrued benefit liability for other benefits in 2001 and 2000 was $6 million and $15 million, respectively.

Unrecognized prior service costs and the net gains are amortized on a straight-line basis over the average remaining service period of active plan participants. The transition obligations for pension benefits and other benefits are being amortized over 17.5 years from 1987.

Net benefit income (cost) was as follows:

	Pension Benefits December 31,			Other Benefits December 31,		
(in millions)	2001	2000	1999	2001	2000	1999
Service cost for benefits earned	$(128)	$(119)	$(121)	$(21)	$(17)	$(19)
Interest cost	(420)	(386)	(347)	(74)	(72)	(69)
Expected return on assets	645	679	634	83	91	83
Amortized prior service and transition cost	(55)	(55)	(25)	(28)	(28)	(27)
Actuarial gain recognized	83	183	111	21	32	20
Settlement gain	—	6	—	—	18	—
Benefit income (cost)	$ 125	$ 308	$ 252	$(19)	$ 24	$(12)

The Utility's share of the net benefit income for pensions in 2001, 2000, and 1999 was $127 million, $302 million, and $253 million, respectively.

The Utility's share of the net benefit income for other benefits in 2000 was $7 million, while the Utility's share of the net benefit cost for other benefits in 2001 and 1999 was $19 million and $9 million, respectively.

Net benefit income (cost) was calculated using expected return on plan assets of 8.5 percent for both pension and other benefits. 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). In 1999, actual return on plan assets exceeded expected return, while actual return on plan assets was below that expected in 2001 and 2000.

In conformity with SFAS No. 71, regulatory adjustments have been recorded in the Consolidated Statements of Operations and Consolidated Balance Sheets of the Utility which reflect the difference between Utility pension income determined for accounting purposes and Utility pension income determined for ratemaking, which is based on a funding approach. The CPUC has authorized the Utility to recover the costs associated with its other benefit plans for 1993 and beyond. Recovery is based on the lesser of the annual accounting costs or the annual contributions on a tax-deductible basis to the appropriate trusts. Recovery of post-employment benefit costs resulted in regulatory liabilities as of December 31, 2001, and 2000, of $44 million and $34 million, respectively.

The following actuarial assumptions were used in determining the plans' funded status and net benefit income (cost). Year-end assumptions are used to compute funded status, while prior year-end assumptions are used to compute net benefit income (cost).

	Pension Benefits December 31,			Other Benefits December 31,		
	2001	2000	1999	2001	2000	1999
Discount rate	7.25%	7.50%	7.50%	7.25%	7.50%	7.50%
Average rate of future compensation increases	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Expected return on plan assets	8.50%	8.50%	8.50%	8.50%	8.50%	9.00%

The assumed health care cost trend rate for 2002 is approximately 7.5 percent, grading down to an ultimate rate in 2005 and beyond of approximately 6 percent. The assumed health care cost trend rate can have a significant effect on the amounts reported for health care plans. A 1-percentage point change would have the following effects:

(in millions)	1-Percentage Point Increase	1-Percentage Point Decrease
Effect on total service and interest cost components	$ 1	$ (11)
Effect on post retirement benefits obligation	$11	$(100)

Defined Contribution 401(k) Benefits

PG&E Corporation and its subsidiaries also sponsor defined contribution pension plans. These plans are intended to qualify under Sections 401(a), 409(a), and 501(a) of the Internal Revenue Code. The plans provide for tax-deferred salary deductions and after-tax employee contributions as well as employer contributions, all of which can be designated by the employee to investments of their choice available within their plan, including units of PG&E Corporation common stock. Employer contributions include matching and/or basic contributions. For certain plans, 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 their plan at any time once they have been credited to their account. Employee contribution expense reflected in the accompanying PG&E Corporation Consolidated Statements of Operations totaled $48 million, $60 million, and $53 million, for the years ended December 31, 2001, 2000, and 1999, respectively.

Long-Term Incentive Program

PG&E Corporation maintains a Long-Term Incentive Program (Program) that permits various stock-based incentive awards to be granted to non-employee directors, executive officers, and other employees of the PG&E Corporation and its subsidiaries. The Stock Option Plan, the Performance Unit Plan, and the Non-Employee

Director Stock Incentive Plan (each of which is a component of the Program) provide incentives based on PG&E Corporation's financial performance over time.

Stock Option Plan (SOP)

The SOP provides for grants of stock options to eligible participants with or without associated stock appreciation rights and dividend equivalents. At December 31, 2001, 45,860,031 shares of PG&E Corporation common stock had been authorized for award under the SOP, with 11,779,626 shares still available under the SOP. Options granted in 2001 were measured using two sets of assumptions under the Black-Scholes valuation method deriving weighted average fair values of $6.01 per share for 5,736,300 options granted and $5.80 per share for 5,670,852 options granted at their respective date of grant, while options granted in 2000 and 1999 had weighted average fair values at their date of grant of $3.26 and $4.19 per share, respectively, using the Black-Scholes valuation method. Significant assumptions used in the Black-Scholes valuation method for shares granted in 2001 (two sets of assumptions used for 2001), 2000, and 1999 were: expected stock price volatility of 33.00 percent and 29.05 percent (2001), 20.19 percent and 16.79 percent, respectively; expected dividend yield of zero percent and 4.35 percent (2001), 5.18 percent and 3.77 percent, respectively; risk-free interest rate of 5.24 percent and 5.95 percent (2001), 6.10 percent and 4.69 percent, respectively; and an expected 10-year life for all periods.

Outstanding stock options become exercisable on a cumulative basis at one-third each year commencing two years from the date of grant and expire ten years and one day after the date of grant. Options outstanding at December 31, 2001, had option prices ranging from $11.80 to $34.25, and a weighted average remaining contractual life of 7.6 years.

The following table summarizes the SOP's activity at and for the years ended December 31:

	2001		2000		1999	
(shares in millions)	Shares	Weighted Average Option Price	Shares	Weighted Average Option Price	Shares	Weighted Average Option Price
Outstanding—beginning of year	24.3	$25.90	16.4	$29.42	11.1	$28.35
Granted during year	11.4	14.33	10.2	20.03	7.0	30.94
Exercised during year	(0.1)	31.96	(1.2)	23.52	(0.5)	25.86
Cancellations during year	(1.5)	23.55	(1.1)	26.57	(1.2)	29.82
Outstanding—end of year	34.1	22.11	24.3	25.90	16.4	29.42
Exercisable—end of year	10.9	27.86	6.3	27.73	3.0	29.08

The following summarizes information for options outstanding and exercisable at December 31, 2001. Of the outstanding options at December 31, 2001, 11,123,700 shares had exercise prices ranging from $11.80 to $16.01 with a weighted average remaining contractual life of 9.3 years, of which 52,800 shares were exercisable at a weighted average exercise price of $13.42, while 11,815,293 shares had option prices ranging from $19.56 to $29.06, with a weighted average remaining contractual life of 7.3 years, of which 4,044,132 shares were exercisable at a weighted average exercise price of $22.70, and 11,141,412 shares had option prices ranging from $30.50 to $34.25, with a weighted average remaining contractual life of 6.3 years, of which 6,835,665 shares were exercisable at a weighted average exercise price of $31.03.

In addition, 165,000 options were granted on January 2, 2002, at an option price of $19.45, the then-current market price of PG&E Corporation common stock.

Performance Unit Plan (PUP)

Under the PUP, PG&E Corporation grants performance units to certain officers of PG&E Corporation and its subsidiaries. The performance units vest one-third in each of the three years following the year of grant. The number of performance units granted and the amount of compensation expense recognized in connection with the issuance of performance units during the years ended December 31, 2001, 2000, and 1999, were not material.

Non-Employee Director Stock Incentive Plan (NEDSIP)

Under the NEDSIP, each person who is a non-employee director on the first business day of the applicable calendar year is entitled to receive stock-based grants with a total aggregate equity value of $30,000, composed of (1) restricted shares of PG&E Corporation common stock valued at $10,000 (based on the closing price of PG&E

Corporation common stock on the first business day of the year), and (2) a combination of non-qualified stock options and common stock equivalents with a total equity value of $20,000, based on equity value increments of $5,000. The exercise price of stock options is equal to the fair market value of PG&E Corporation common stock on the date of grant. Restricted stock and stock options vest over a five-year period following the date of grant, except upon a director's mandatory retirement from the Board at age 70, upon a director's death or disability, or in the event of a change in control, in which cases the restricted stock and stock options will vest immediately. The component of the NEDSIP representing stock options at December 31, 2001, 2000, and 1999, is included in the above data under Stock Option Plan (SOP) in accordance with SFAS No. 123 and APB No. 25. The component of the NEDSIP representing expense recognized in connection with issuance of restricted stock and common stock equivalents during the years ended December 31, 2001, 2000, and 1999, was not material.

PG&E Corporation Supplemental Retirement Savings Plan (SRSP)

The SRSP provides supplemental retirement alternatives to eligible senior officers and key employees of PG&E Corporation and its subsidiaries by allowing participants to defer portions of their compensation, including salaries, amounts awarded under the PUP, and other incentive awards. The SRSP also provides a means for eligible participants to receive and invest employer contribution amounts exceeding contribution limits within the various defined contribution plans sponsored by PG&E Corporation and its subsidiaries. Under the employee-elected deferral component of the SRSP, an eligible employee may defer all or part of his or her PUP (if eligible) and other incentive awards, and 5 to 50 percent of his or her monthly salary each month. Under the supplemental employer-provided retirement benefits component of the SRSP, eligible employees receive full employer matching and basic contributions in excess of limitations set out by the Internal Revenue Code as qualified under defined contribution 401(k) plans into a non-qualified account. A separate non-qualified account is maintained for each eligible employee to hold any deferred and/or employer-contributed amounts with investment options available for the employee's designation. PG&E Corporation recognizes any gain or loss from these investments and adjusts each employee account on a quarterly basis. Expense related to deferred amounts is recognized in the period in which it is earned by the employee and accrued until paid under the terms of the plan. Employer contribution expense and expenses related to gain or loss from investments of contributed and deferred amounts recognized in connection with the SRSP during the years ended December 31, 2001, 2000, and 1999, was not material.

Executive Stock Ownership Program (ESOP)

The ESOP sets certain stock ownership targets for certain employees. The targets are set as a multiple of the employees' base salary and vary according to the employee. To the extent an employee achieves and maintains the stock ownership targets, the employee will be entitled to receive additional common stock equivalents called Special Incentive Stock Ownership Premiums (SISOPs) to be credited to his or her SRSP account. The SISOPs vest three years after the date of grant and are subject to forfeiture if the employee fails to maintain his or her respective stock ownership target. The amount of expense related to SISOPs granted including the net of appreciation and depreciation on the stock price of PG&E Corporation common stock for the years ended December 31, 2001, 2000, and 1999, was not material.

Retention Programs

PG&E Corporation implemented various retention mechanisms in 2001. These mechanisms awarded identified key personnel of PG&E Corporation and its subsidiaries with lump-sum cash payments and/or units of Special Senior Executive Retention Grants. The Special Senior Executive Retention Grants provide certain employees with phantom PG&E Corporation restricted stock units that, except in the event of a change in control, or on the employees' death or disability, vest no earlier than December 31, 2003. Vesting of one half of the awards is also dependent upon meeting certain performance measures. The number of units of phantom stock granted under these mechanisms in 2001 totaled 3,044,600. The phantom stock units are marked-to-market based on the market price of PG&E Corporation common stock, and amortized into income over a four-year period. The expense recognized in connection with these retention mechanisms, including cash payments and phantom restricted stock units, for the year ended December 31, 2001, totaled $29 million.

Note 14: Income Taxes

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

(in millions)	PG&E Corporation Year Ended December 31, 2001	2000	1999	Utility Year Ended December 31, 2001	2000	1999
Current	$1,017	$(1,261)	$1,002	$ 902	$(1,224)	$1,133
Deferred	(370)	(728)	(702)	(267)	(891)	(433)
Tax credits, net	(39)	(39)	(52)	(39)	(39)	(52)
Income tax (benefit) expense	$ 608	$(2,028)	$ 248	$ 596	$(2,154)	$ 648

The significant components of net deferred income tax liabilities were:

	PG&E Corporation Year ended December 31, 2001	2000	Utility Year ended December 31, 2001	2000
Deferred income tax assets:				
Customer advances for construction	$ 252	$ 176	$ 252	$ 176
Unamortized investment tax credits	110	114	110	114
Reserve for damages	254	203	254	203
Environmental reserve	161	161	161	161
ISO energy purchases	353	—	353	—
Other	445	355	217	172
Total deferred income tax assets	1,575	1,009	1,347	826
Deferred income tax liabilities:				
Regulatory balancing accounts	369	17	369	17
Property related basis differences	2,357	2,389	1,665	1,719
Income tax regulatory asset	83	68	83	65
Other	505	360	323	126
Total deferred income tax liabilities	3,314	2,834	2,440	1,927
Total net deferred income taxes	1,739	1,825	1,093	1,101
Classification of net deferred income taxes:				
Included in current liabilities	73	169	65	172
Included in noncurrent liabilities	1,666	1,656	1,028	929
Total net deferred income taxes	$1,739	$1,825	$1,093	$1,101

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

	PG&E Corporation Year Ended December 31, 2001	2000	1999	Utility Year Ended December 31, 2001	2000	1999
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)	4.8	4.4	10.1	5.0	4.3	6.2
Effect of regulatory treatment of depreciation differences	1.6	(2.1)	51.7	1.7	(2.0)	9.4
Tax credits, net	(3.9)	0.7	(19.9)	(2.5)	0.7	(3.6)
Effect of foreign earnings at different tax rates	(0.1)	0.1	(1.3)	—	—	—
Stock sale differences	—	(1.4)	(6.8)	—	—	—
Stock sale valuation allowance	—	1.5	30.2	—	—	—
Other, net	(1.6)	(0.3)	(4.0)	(2.2)	0.2	(1.9)
Effective tax rate	35.8%	37.9%	95.0%	37.0%	38.2%	45.1%

At December 31, 2001, PG&E Corporation had $25 million of California net operating loss (NOL) carryforward that will expire at the end of 2005. As a result of the Utility's 2000 unrecovered purchased power costs, PG&E Corporation and the Utility incurred a federal NOL for 2000. The NOL was carried back to prior years in accordance with federal income tax law, resulting in a refund of approximately $1.2 billion, of which $1.1 billion was refunded to the Utility.

During 1999, PG&E Corporation generated a capital loss carryforward from the sale of stock of approximately $225 million, which has been fully utilized by the end of 2001. Accordingly, at December 31, 2001, no valuation allowance exists.

Note 15: Commitments

Tolling Agreements

PG&E NEG

PG&E NEG, through PG&E ET, entered into tolling agreements with several counterparties giving PG&E NEG the right to sell electricity generated by facilities owned and operated by other parties. The facilities are under construction and expected to begin operations in 2002 and 2003. Under the tolling agreements, PG&E NEG, at its discretion, supplies the fuel to the power plants, and then sells the plant's output in the competitive market. Committed payments are reduced if the plant facilities do not achieve agreed-upon levels of performance criteria. At December 31, 2001, the annual estimated committed payments under such contracts ranged from approximately $33 million to $211 million, resulting in total committed payments over the next 27 years of approximately $4 billion commencing at the completion of construction. During 2001, approximately $13 million was paid under tolling agreements.

Estimated amounts payable in future years are as follows:

(in millions)	
2002	$ 50
2003	135
2004	191
2005	204
2006	201
Thereafter	3,461
Total	$4,242

Power Purchase Contracts

Utility

Qualifying Facilities, Irrigation Districts, and Water Agencies

The Utility is required under current CPUC regulations to purchase electric energy and capacity provided by independent power producers that are QFs under the Public Utility Regulatory Policies Act of 1978. The CPUC required the California utilities to enter into a series of long-term power purchase agreements (PPAs) and approved the applicable terms, conditions, prices, and eligibility requirements.

The PPAs require the Utility to pay for energy and capacity. Energy payments are based on the QF project's actual electrical output, and capacity payments are based on the QF project's total available capacity and contractual capacity commitment. Capacity payments may be reduced if the facility does not meet the performance requirements specified in the PPAs. Costs associated with these contracts are eligible for recovery by the Utility through the generation component of the electric rates charged to the Utility's customers. Most of the PPAs expire on various dates through 2028, though some have no stated expiration date. Deliveries under the PPAs account for approximately 21 percent of the Utility's 2001 electric energy requirements, and no single contract accounted for more than 5 percent of the Utility's energy needs.

Prior to 2000, the Utility negotiated with several QFs for early termination of their PPAs. At December 31, 2001, the total discounted future payments due under the renegotiated contracts were approximately $144 million.

As a result of the energy crisis and the Utility's bankruptcy filing, a number of QFs requested the Bankruptcy Court to either terminate their contracts requiring them to sell power to the Utility, or have the contracts suspended for the summer of 2001 so the QFs could sell power at market-based rates. The Bankruptcy Court ordered the QFs to negotiate with the Utility, pending its review of each agreement, and it authorized payment for services delivered subsequent to the Utility's filing for bankruptcy. In July 2001, the Utility signed five-year agreements with 197 of its QFs, ensuring the Utility and its customers receive a reliable supply of electricity at an average energy price of $0.054 per kWh. Under the terms of these assumption agreements, the Utility will assume the QF contracts and pay the pre-petition debt on these 197 QF contracts, totaling $845 million, on the effective date of the plan of reorganization. The total amount the Utility owed to QFs when it filed for bankruptcy protection was approximately $1 billion. The agreements represent approximately 85 percent of debt owed to QFs. For certain of these QFs, if the effective date has not occurred by July 15, 2003, the Utility will pay 2 percent of the principal amount of the pre-petition debt per month until the effective date of the Utility's plan of reorganization or until July 15, 2005, when it will pay the remaining pre-petition debt.

On December 21, 2001, the Bankruptcy Court approved supplemental agreements entered into between the Utility and several of its larger QFs to resolve the issue of the applicable interest rate to be applied to the pre-petition debt. The supplemental agreements modify the assumption agreements by (1) setting the interest rate for pre-petition debt at 5 percent per annum, (2) providing for a "catch-up payment" of all accrued and unpaid interest (calculated from the date of default through December 31, 2001) that was paid on December 31, 2001, and (3) providing for an accelerated payment of the principal amount of the pre-petition debt (and interest thereon) in 12 equal monthly payments of principal (and interest thereon) commencing on December 31, 2001, and continuing through November 30, 2002, or in the event the effective date of the plan of reorganization occurs before the last monthly payment is made, the remaining unpaid principal and accrued but unpaid interest thereon, shall be paid in full on the effective date. The Utility believes that, similar to the experience with the assumption agreements, a large number of the QFs will also wish to enter into similar supplemental agreements.

At December 31, 2001, the undiscounted future minimum payments related to QFs are as follows:

(in millions)	Energy Payments	Capacity Payments
2002	$ 990	$ 490
2003	960	480
2004	950	470
2005	940	470
2006	850	460
Thereafter	4,970	3,240
Total	$9,660	$5,610

The Utility also 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, whether or not any energy is supplied (subject to the supplier's retention of the FERC's authorization), and variable payments for operation and maintenance costs incurred by the suppliers. These contracts expire on various dates from 2004 to 2031. Irrigation district and water agency deliveries in the aggregate account for approximately 3 percent of the Utility's 2001 electric energy requirements.

At December 31, 2001, the undiscounted future minimum payments related to irrigation districts and water agency agreements are as follows:

(in millions)	
2002	$ 33
2003	33
2004	33
2005	26
2006	26
Thereafter	194
Total	$345

The amount of energy received and the total payments made under QF, irrigation district, and water agency PPAs are as follows:

	Year ended December 31,		
(in millions, except megawatt-hours)	2001	2000	1999
Megawatt-hours received	21,019	25,446	25,910
Energy payments	$ 1,454	$ 1,549	$ 837
Capacity payments	473	519	539
Irrigation district and water agency payments	54	56	60

Bilateral Contracts

Despite the lack of established criteria for cost recovery from the CPUC, the Utility entered into several bilateral forward electric contracts in October 2000 to stabilize the escalating costs of purchasing electricity. Several of these contracts were terminated by the counterparties under the terms of the contracts because either the Utility filed for bankruptcy, or the Utility's credit rating declined to below investment grade. The terms of the contracts require that the contracts be settled at the market value of the contract at the time of termination. The estimated net gain on the terminated contracts of $552 million has been recognized as a reduction to the cost of electric energy in the Consolidated Statements of Operations.

At December 31, 2001, the Utility had two bilateral contracts outstanding which expire in 2003. The undiscounted future minimum payments due under these contracts are $196 million in each of the years, 2002 and 2003. Under normal purchases and sales accounting, the Utility does not recognize the cost of the contracts until the energy is delivered. At December 31, 2001, the outstanding bilateral contracts have an estimated negative market value of $168 million. This value would be recorded as cost of electric energy in the Consolidated Statements of Operations if these contracts failed to meet the normal purchases and sales exemption of SFAS No. 133. The provisions of one of the contracts allows the counterparty to terminate the contract without penalty at fair value while the Utility is in a Chapter 11 bankruptcy filing. The Utility expects that the physical delivery of power will continue through the duration of the contract period.

PG&E NEG

PG&E NEG, through its indirect subsidiary, USGenNE, assumed rights and duties under several power purchase contracts with third-party independent power producers as part of the acquisition of the New England Electric System (NEES) assets. At December 31, 2001, these agreements provided for an aggregate of 800 MW of capacity. Under the transfer agreement, PG&E NEG is required to pay to NEES amounts due to the third-party power producers under the power purchase contracts. The approximate dollar amounts under these agreements are as follows:

(in millions)	
2002	$ 252
2003	255
2004	261
2005	262
2006	265
Thereafter	1,973
Total	$3,268

Natural Gas Supply and Transportation Commitments

Utility

Under current CPUC regulations, the Utility purchases natural gas from its various suppliers based on economic considerations, consistent with regulatory, contractual, and operational constraints. The Utility has long-term gas transportation service agreements with various Canadian and interstate pipeline companies. The total demand charges that the Utility will pay each year may change due to changes in tariff rates. These agreements include provisions for payment of fixed demand charges for reserving firm capacity on the pipelines. The total demand and volumetric transportation charges the Utility incurred under these agreements were $239 million, $94 million, and $97 million in 2001, 2000, and 1999, respectively. These amounts include payments made by the

Utility to PG&E GTN of $41 million, $46 million, and $47 million in 2001, 2000, and 1999, respectively, which are eliminated in the consolidated financial statements of PG&E Corporation.

The Utility also has long-term gas supply contracts with various Canadian and interstate gas companies. The contracts commit the Utility to purchase gas through October 2002, and total $260 million. On January 31, 2001, the CPUC authorized the Utility to pledge its gas accounts receivables and its gas inventories for up to 90 days (subsequently extended to 180 days and expiring on May 1, 2002), and at December 31, 2001, total gas accounts receivable pledged amounted to $268 million. At December 31, 2001, the Utility's obligations related to natural gas transportation and supply commitments held pursuant to long-term contracts are as follows:

(in millions)	
2002	$358
2003	110
2004	88
2005	77
2006	21
Thereafter	5
Total	$659

PG&E NEG

PG&E NEG, through its subsidiaries PG&E Gen and PG&E ET, has entered into various gas supply and firm transportation agreements with various pipelines and transporters to provide fuel transportation services to its own power plants and other customers. Under these agreements, PG&E NEG must make specific minimum payments each month. The approximate dollar obligations under these gas supply and transportation agreements are as follows:

(in millions)	
2002	$ 126
2003	113
2004	107
2005	98
2006	92
Thereafter	483
Total	$1,019

Turbine Purchase Commitments

PG&E NEG

PG&E NEG has entered into commitments for turbines and other equipment necessary to meet its growth plans. Most significantly, PG&E NEG has secured contractual commitments and options for combustion turbines and related equipment representing 14,000 MW of net generating capacity including 3,868 MW in advanced development. Subject to maintaining PG&E NEG's credit quality and raising necessary capital, and subject to energy market conditions and the availability of attractive opportunities, PG&E NEG will deploy these turbines on projects in development, or cancel PG&E NEG's commitments.

In 2000, PG&E NEG entered into agreements created to own and facilitate the development, construction and financing of generating facilities that will use 44 turbines to be manufactured by General Electric and Mitsubishi. PG&E Corporation and PG&E NEG committed to provide up to $314 million in equity to meet PG&E NEG's obligations. At May 29, 2001, PG&E NEG had incurred $216 million of expenditures. At December 31, 2001, PG&E NEG has borrowed $221 million against the total borrowing capacity of its $280 million revolving credit facility. The facility is due to be fully repaid on December 31, 2003. PG&E NEG's turbine-related equity commitments have been terminated.

Out-of-Market Contractual Commitments

PG&E NEG

In connection with USGenNE's acquisition of NEES generating assets in 1998, USGenNE also assumed PPAs, gas commodity and transportation agreements (collectively, Gas Agreements), and Standard Offer Agreements. Commitments contained in the underlying PPAs, Gas Agreements, and Standard Offer Agreements, were recorded at fair value, based on management's estimate of either or both the gas commodity and gas transportation markets and electric markets over the life of the underlying contracts, discounted at a rate commensurate with the risks associated with such contracts. Standard Offer Agreements reflect a commitment to supply electric capacity and energy necessary for certain NEES affiliates to meet their obligations to supply fixed-rate service.

PPAs and Gas Agreements are amortized on a straight-line basis over their specific lives. The Standard Offer Agreements are amortized using an accelerated method, since the decline in value is greater in earlier years due to increasing contract pricing terms designed to reduce demand for PG&E NEG's supply service over time. The carrying value of the out-of-market obligations is as follows:

(in millions)	Amortization Period	December 31, 2001	December 31, 2000
PPA's	1-20 years	$541	$599
Gas Agreements	8-13 years	172	188
Standard Offer Agreements	6-7 years	86	154
		799	941
Less: Current portion		116	141
Long-term portion		$683	$800

Long-Term Receivables

PG&E NEG

PG&E NEG receives from a wholly owned subsidiary of NEES payments related to the assumption of power supply agreements, which are payable monthly through January 2008. At December 31, 2001, future cash receipts under this arrangement are as follows:

(in millions)	
2002	$120
2003	112
2004	107
2005	107
2006	108
Thereafter	117
	671
Discounted portion	(135)
Net amount receivable	536
Less: Current portion	81
Long-term receivable	$455

The long-term receivables are valued at the present value of the scheduled payments using a discount rate that reflects NEES' credit rating on the date of acquisition. The current portion is included in prepaid expenses, deposits, and other in the Consolidated Balance Sheets.

Operating Leases

Utility

The Utility has entered into several operating lease agreements for office space. The leases expire on various dates between 2004 and 2009. The approximate obligations under these operating lease agreements at December 31, 2001, are as follows:

(in millions)	
2002	$11
2003	11
2004	12
2005	12
2006	11
Thereafter	18
Total	$75

Operating lease expense amounted to $14 million, $12 million, and $11 million in 2001, 2000, and 1999, respectively.

PG&E NEG

PG&E NEG and its subsidiaries have entered into several operating lease agreements for generating facilities and office space. Lease terms vary between three and 48 years. In November 1999, a subsidiary of PG&E NEG entered into a $479 million sale-leaseback transaction whereby the subsidiary sold and leased back a pumped storage station under an operating lease.

The approximate obligations under these operating lease agreements at December 31, 2001, are as follows:

(in millions)	
2002	$ 72
2003	70
2004	79
2005	79
2006	80
Thereafter	895
Total	$1,275

Operating lease expense amounted to $54 million, $70 million, and $70 million in 2001, 2000, and 1999, respectively.

Nuclear Fuel Agreements

Utility

The Utility has purchase agreements for nuclear fuel components and services for use in operating the Diablo Canyon generating facility. These agreements run variable lengths, from two to five years. These agreements are intended to ensure long-term fuel supply, but also permit the Utility the flexibility to take advantage of short-term supply opportunities. Deliveries under five of the eight contracts in place at the end of 2001 will end by 2005. In most cases, the Utility's nuclear fuel contracts are requirements-based, with the Utility's obligations linked to the continued operation of its Diablo Canyon generating plant.

At December 31, 2001, the undiscounted obligations under nuclear fuel agreements are as follows:

(in millions)	
2002	$ 81
2003	35
2004	34
2005	12
2006	14
Thereafter	11
Total	$187

Payments for nuclear fuel amounted to $50 million, $78 million, and $56 million in 2001, 2000, and 1999, respectively.

The Utility relies on large, well established international producers for its long-term agreements in order to diversify its commitments and ensure security of supply. Pricing terms are also diversified, ranging from fixed prices to base prices that are adjusted using published factors. Due to recent events in the market, the Utility may experience higher costs for nuclear fuel purchases in the near term. In January 2002, the International Trade Commission proposed up to 50 percent tariffs on imports from certain countries providing nuclear fuel. Due to the diversification of the Utility's nuclear fuel agreements, if these tariffs remain in place, then the Utility's nuclear fuel costs may rise since there are only a limited number of suppliers in the world for such fuel.

WAPA Sales Contract Commitments

Utility

In 1967, the Utility and the Western Area Power Administration (WAPA) entered into a long-term power contract governing the interconnection of the Utility's and WAPA's transmission systems, WAPA's use of the Utility's transmission and distribution system, and the integration of the Utility's and WAPA's loads and resources. The contract provided the Utility access to surplus hydroelectric generation at favorable prices and provided WAPA with electricity when its own resources were not sufficient to meet its requirements. The contract terminates on December 31, 2004.

As a result of California's electric industry restructuring (EIR) in 1998, the Utility was required to procure the energy it needed to meet its own and WAPA's requirements from the PX. This caused the Utility to be exposed to market-based energy pricing rather than the cost of service-based energy pricing that had been presumed when the contract was executed. As a result, the Utility paid substantially more for the energy it purchased on behalf of WAPA than it received for the sales.

The Utility's cost going forward to procure power to fulfill its obligations to WAPA under the contract is uncertain. However, it is expected that the cost of the power the Utility purchases to meet its obligation to WAPA will be greater than the price the Utility receives from WAPA under the contract. Under AB 1890, the Utility's retail ratepayers pay for this difference as a power purchase cost. The amount of the difference between the Utility's cost to meet its obligations to WAPA and the revenues it receives from WAPA cannot be accurately estimated since both the purchase price and the amount of energy WAPA will need from the Utility through the end of the contract are uncertain. Though it is not indicative of future sales commitments or sales-related costs, WAPA purchased 5,425 MWh, 4,049 MWh, and 2,845 MWh of energy from the Utility in 2001, 2000, and 1999, respectively. Given the recent decline in the market price for energy and lower forecasts of energy prices going forward, the Utility expects that its cost to meet its obligations to WAPA under the contract to be significantly less than 2001 and 2000.

Other Commitments

Utility

The CPUC directed the state's larger investor-owned utilities to fund two load-control and self-generation programs at an annual cost of $138 million for four years beginning in 2001. The Utility's portion of the annual costs is $63 million per year. Under the self-generation program, the Utility offers financial incentives to customers who install up to one megawatt of certain kinds and sizes of on-site distributed energy projects.

The CPUC has stated that it will allow costs of this program, which are not recovered during the rate freeze to be recovered after the rate freeze ends. The Utility receives no rate of return on its investment in these programs, and the CPUC has not addressed how or when these costs will be recovered.

PG&E NEG

PG&E NEG has entered into long-term service agreements for the maintenance and repair of certain of its combustion turbine or combined-cycle generating plants under construction. These agreements, which are for periods up to 18 years, may be terminated in the event a planned construction project is cancelled. PG&E NEG has entered into certain agreements with certain local governments that provide for payments in lieu of property taxes. Annual amounts for long-term service agreements and payments in lieu of property taxes committed for the next five years under the current construction plan are as follows at December 31, 2001:

(in millions)	
2002	$ 31
2003	24
2004	17
2005	18
2006	20
Thereafter	134
Total	$244

Note 16: Contingencies

Nuclear Insurance

The Utility has insurance coverage for property damage and business interruption losses as a member of Nuclear Electric Insurance Limited (NEIL). Under this insurance, if a nuclear generating facility suffers a loss due to a prolonged accidental outage, the Utility may be subject to maximum retrospective assessments of $26 million (property damage) and $9 million (business interruption), in each case per policy period, in the event losses exceed the resources of NEIL.

The Utility has purchased primary insurance of $200 million for public liability claims resulting from a nuclear incident. The Utility has secondary financial protection, which provides an additional $9.3 billion in coverage, which is mandated by federal legislation. It provides for loss sharing among utilities owning nuclear generating facilities if a costly incident occurs. If a nuclear incident results in claims in excess of $200 million, then the Utility may be assessed up to $176 million per incident, with payments in each year limited to a maximum of $20 million per incident.

Surety Bonds

Utility

The Utility must provide collateral to maintain its status as a self-insurer for workers' compensation. Acceptable forms of collateral include surety bonds, letters of credit, cash, or securities. On May 9, 2001, the State Department of Industrial Relations (DIR) approved the Utility's security deposit of approximately $401 million in surety bonds. The Utility's reimbursement obligations under these bonds and the underlying workers' compensation obligations are guaranteed by PG&E Corporation.

In February 2001, several surety companies provided cancellation notices, citing concerns about the Utility's financial situation. However, the state has not agreed to release the cancelling sureties from their obligations for claims occurring prior to the cancellation and has continued to apply the cancelled bond amounts, totaling $185 million, towards the required $401 million amount of collateral. The Utility was able to supplement the difference through three additional active surety bonds totaling $216 million. The cancelled bonds have not, to date, impacted the Utility's self-insured status under California law, or its ability to meet current plan obligations.

Environmental Remediation

Utility

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 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 or disposal of potentially hazardous materials. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if it did not deposit those substances on the site.

The Utility records an environmental remediation liability when site assessments indicate remediation is probable and a range of reasonably likely clean-up costs can be estimated. The Utility reviews its remediation liability quarterly for each identified site. The liability is an estimate of costs for site investigations, remediation, operations and maintenance, monitoring, and site closure using (1) current technology, (2) enacted laws and regulations, (3) experience gained at similar sites, and (4) 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 lower end of this range.

Hazardous Waste Remediation

The Utility had an environmental remediation liability of $295 million and $320 million at December 31, 2001, and 2000, respectively. The $295 million accrued at December 31, 2001, includes (1) $139 million related to the pre-closing remediation liability associated with divested generation facilities, and (2) $156 million related to remediation costs for those generation facilities that the Utility still owns, manufactured gas plant sites, and gas gathering compressor stations. Of the $295 million environmental remediation liability, the Utility has recovered $193 million through rates, and expects to recover the balance in future rates. The Utility also is recovering its costs from insurance carriers and from other third parties as appropriate.

On June 28, 2001, the Bankruptcy Court authorized the Utility to continue its hazardous waste remediation program and to expend:

- Up to $22 million in each calendar year in which the Chapter 11 case is pending to continue its hazardous substance remediation programs and procedures; and
- Any additional amounts necessary in emergency situations involving post-petition releases or threatened releases of hazardous substances subject to the Bankruptcy Court's specific approval.

At December 31, 2001, the Utility estimates total future costs for hazardous waste remediation at identified sites, including divested fossil-fueled power plants to be $295 million (undiscounted). The cost of the hazardous substance remediation ultimately undertaken by the Utility is difficult to estimate. A change in the estimate 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. If other potentially responsible parties are not financially able to contribute to these costs or further investigation indicates that the extent of contamination or necessary remediation is greater than anticipated, the Utility's future cost could increase by as much as $446 million. The Utility estimates the upper limit of the range using assumptions least favorable to the Utility, based upon a range of reasonably possible outcomes. Costs may be higher if the Utility is found to be responsible for clean-up costs at additional sites or expected outcomes change.

Environmental Claims

The California Attorney General, on behalf of various state environmental agencies, filed claims in the Utility's bankruptcy proceeding for environmental remediation at numerous sites aggregating to approximately $770 million. For most if not all of these sites, the Utility is in the process of remediation in cooperation with the relevant agencies or would be doing so in the future in the normal course of business. In addition, for the majority of the remediation claims, the state would not be entitled to recover these costs unless they accept responsibility to clean up the sites, which is unlikely. Since the proposed plan of reorganization provides that the Utility intends to respond to these types of claims in the regular course of business, and since the Utility has not argued that the bankruptcy proceeding relieves the Utility of its obligations to respond to valid environmental remediation orders, the Utility believes the claims seeking specific cash recoveries are invalid.

Moss Landing

In December 1999, the Utility was notified by the purchaser of its former Moss Landing power plant that it had violated the plant's National Pollutant Discharge Elimination System (NPDES) permit issued by the Central Coast Regional Water Quality Control Board (Central Coast Board). A claim has been filed by the California Attorney General in the Utility's bankruptcy proceeding on behalf of the Central Coast Board seeking unspecified penalties.

Diablo Canyon

The Utility's Diablo Canyon employs a "once-through" cooling water system, which is regulated under a NPDES Permit issued by the Central Coast Board. This permit allows Diablo Canyon to discharge the cooling water at a temperature no more than 22 degrees above ambient receiving water and requires that the beneficial uses of the water be protected. The beneficial uses of water in this region include industrial water supply, marine and wildlife habitat, shellfish harvesting, and preservation of rare and endangered species. In January 2000, the Central Coast Board issued a proposed draft Cease and Desist Order alleging that, although the temperature limit has never been exceeded, Diablo Canyon's discharge was not protective of beneficial uses. In October 2000, the Central Coast Board and the Utility reached a tentative settlement of this matter pursuant to which the Central Coast Board has agreed to find that the Utility's discharge of cooling water from the Diablo Canyon plant protects beneficial uses and that the intake technology reflects the "best technology available" under Section 316(b) of the Federal Clean Water Act. As part of the settlement, the Utility will take measures to preserve certain acreage north of the plant and will fund approximately $5 million in environmental projects related to coastal resources. The parties are negotiating the documentation of the settlement. The final agreement will be subject to public comment and will be incorporated in a consent decree to be entered in California Superior Court. A claim has been filed by the California Attorney General in the Utility's bankruptcy proceeding on behalf of the Central Coast Board seeking unspecified penalties and other relief in connection with Diablo Canyon's operation of its cooling water system.

The Utility believes the ultimate outcome of these matters will not have a material impact on its financial position or results of operations.

PG&E NEG

PG&E NEG anticipates spending up to approximately $337 million, net of insurance proceeds, through 2008 for environmental compliance at current operating facilities. To date, PG&E NEG has spent approximately $8 million of this amount. PG&E NEG believes that a substantial portion of this amount will be funded from its operating cash flow. This amount may change, however, the timing of any necessary capital expenditures could be accelerated in the event of a change in environmental regulations or the commencement of any enforcement proceeding against PG&E NEG.

In May 2000, PG&E NEG received an Information Request from the U.S. Environmental Protection Agency (EPA), pursuant to Section 114 of the Federal Clean Air Act (CAA). The Information Request asked PG&E NEG to provide certain information, relative to the compliance of the Brayton Point and Salem Harbor Generating Stations with the CAA. No enforcement action has been brought by the EPA to date. PG&E NEG has had very preliminary discussions with the EPA to explore a potential settlement of this matter. As a result of this and related regulatory initiatives by the Commonwealth of Massachusetts, PG&E NEG is exploring initiatives that would assist it to achieve significant reductions of sulfur dioxide, nitrogen oxide, and thermal emissions by 2006. PG&E NEG believes that it would meet these requirements through installation of controls at the Brayton Point and Salem Harbor plants and estimates that capital expenditures on these environmental projects will be approximately $266 million over the next five years. PG&E NEG believes that it is not possible to predict at this point whether any such settlement will occur or in the absence of a settlement the likelihood of whether the EPA will bring an enforcement action.

PG&E Gen's existing power plants, including USGenNE facilities, are subject to federal and state water quality standards with respect to discharge constituents and thermal effluents. Three of the fossil-fueled plants owned and operated by USGenNE are operating pursuant to NPDES permits that have expired. For the facilities whose NPDES permits have expired, permit renewal applications are pending, and it is anticipated that all three facilities will be able to continue to operate under existing terms and conditions until new permits are issued. It is estimated that USGenNE's cost to comply with the new permit conditions could be as much as $67 million through 2005. It is possible that the new permits may contain more stringent limitations than prior permits.

In September 2000, USGenNE signed a series of agreements that require USGenNE to alter its existing wastewater treatment facilities at the Brayton Point and Salem Harbor generating facilities. Through December 31, 2001, USGenNE has incurred approximately $8 million and expects to incur another $10 million to complete these improvements. Certain of these costs have been capitalized and a receivable has been recorded for amounts it believes are probable of recovery through insurance proceeds.

Guarantees

Except for a $16 million guarantee by PG&E Corporation provided to PG&E NEG in connection with an office lease, all significant third party guarantees are provided by PG&E NEG, the most significant of which are described below.

Guarantees Supporting Tolling Agreements

A subsidiary of PG&E NEG has entered into a number of tolling agreements. Each tolling agreement is supported by a separate guarantee backing PG&E NEG affiliate's payment obligations over the term of these long-term contracts (9-25 years). PG&E NEG has extended about $600 million of such guarantees with the initial face value varying from $20 million to $250 million declining over time as the future obligation declines. Each of these guarantees contains a trigger event provision that requires PG&E NEG to replace the guarantee or provide alternative collateral in the event that its credit rating drops to below the prescribed grade (generally BBB or Baa2), as measured by S&P and Moody's. As of December 31, 2001, the net exposure under the guarantee supporting agreements was 3.2 percent or $20 million.

Guarantees Supporting Agreements with Third Parties

PG&E NEG and its subsidiaries have issued in excess of $800 million of guarantees in support of various performance and payment obligations under agreements with third parties. Of these guarantees supporting other agreements with third parties, $485 million have investment grade ratings maintenance requirements. In addition, a number of other agreements have specific security provisions requiring maintenance of investment grade ratings. In the event of a downgrade below the trigger level and exhaustion of any cure period, some of these agreements would allow the counterparty to demand payment for any outstanding obligations or contract termination penalties, if any. Others simply provide the counterparty with a right to terminate the contract.

Guarantees Supporting Trading Related Agreements

PG&E NEG's energy marketing, trading, hedging, and risk management operations are conducted with counterparties under various master agreements. These agreements typically provide for reciprocal extension of credit lines based on creditworthiness standards. Net open positions under these agreements are marked-to-market on a routine basis, and if the net exposed position including receivables and payables falls outside of the established credit limits, then additional collateral must be provided. Therefore, key components of a successful energy business consist of creditworthiness, liquidity resources, risk management systems that provide current mark-to-market of all open positions, and a strong credit department to evaluate and manage counterparty credit risk.

In addition to the guarantees supporting tolling agreements, at December 31, 2001, PG&E NEG and its subsidiaries provided $2.3 billion of guarantees to counterparties in support of its energy trading operations. This includes provision of fuel and pipeline capacity to, and sale of energy products from its power plants. These guarantees were provided in favor of approximately 200 counterparties to permit and facilitate physical and financial transactions in gas, pipeline capacity, power, coal, and related commodities and services with these entities. Typically, the overall exposure under these guarantees is only a fraction of the face value of the guarantees, since not all counterparty credit limits are fully utilized at any time and there may be no outstanding transactions or financial exposure underlying an outstanding guarantee. PG&E NEG receives similar deposits, letters of credit, and guarantees as collateral for credit extended by PG&E NEG to these, in many cases, same counterparties. These offsetting exposures can often be netted in lieu of posting alternative collateral. At December 31, 2001, PG&E NEG's net exposure under its guarantees was approximately 8 percent or about $190 million. This exposure is a contingent obligation that could be called only if PG&E NEG or one of its subsidiaries fails to meet and cure a payment obligation.

The continued acceptability of many of these guarantees is dependent on PG&E NEG's maintaining various standards of creditworthiness. As a result, maintenance of investment grade ratings by one or more rating agencies is an important criterion for PG&E NEG and its subsidiaries. If PG&E NEG or its subsidiaries are downgraded by one or more of the rating agencies, PG&E NEG may be required to provide alternative collateral to replace guarantees that no longer meet the creditworthiness standards of the agreements. Therefore, PG&E NEG and its trading subsidiaries maintain substantial cash balances and credit capacity to provide liquidity to its businesses in the event that open credit limits are exceeded through volatility, or in the event of a credit downgrade.

The amount of exposure under master agreements subject to securitization requirements in the event of a credit downgrade of PG&E NEG or its subsidiaries to below investment grade by one or more rating agencies was approximately 5 percent of the outstanding guarantees or $105 million. PG&E NEG manages this risk through maintenance of investment grade credit ratings at several principal operating subsidiaries so that guarantees of one entity could be substituted for another in the event of a credit downgrade of one entity.

Legal Matters

Utility

The Utility's Chapter 11 bankruptcy on April 6, 2001, discussed in Note 2, automatically stayed the litigation described below against the Utility.

Chromium Litigation

There are 15 civil suits pending against the Utility in several California state courts. Two of these suits also name PG&E Corporation as a defendant. The suits seek an unspecified amount of compensatory and punitive damages for alleged personal injuries resulting from alleged exposure to chromium in the vicinity of the Utility's gas compressor stations at Hinkley, Kettleman, and Topock, California. Currently, there are claims pending on behalf of approximately 1,290 individuals.

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

There have been approximately 1,260 claims filed with the Bankruptcy Court (by most of the plaintiffs in the 15 cases and other individuals) alleging that exposure to chromium in soil, air, or water near the Utility's compressor stations at Hinkley, Kettleman, or Topock, California caused personal injuries, wrongful death, or other injuries. Approximately 1,035 of these claimants have filed proofs of claim requesting an approximate aggregate amount of $580 million and another approximately 225 claimants have filed claims for an "unknown amount." On November 14, 2001, the Utility filed objections to these claims and requested the Bankruptcy Court to transfer the chromium claims to the Federal District Court. On January 8, 2002, the Bankruptcy Court denied the Utility's request to transfer the chromium claims and granted the claimants' motion for relief from stay so that the state court lawsuits pending before the Utility filed its bankruptcy petition can proceed.

The Utility has recorded a reserve in its financial statements in the amount of $160 million for these matters. PG&E Corporation and the Utility believe that, after taking into account the reserves recorded at December 31, 2001, the ultimate outcome of this matter will not have a material adverse impact on PG&E Corporation's or the Utility's financial condition or future results of operations.

Natural Gas Royalties Litigation

This litigation involves the consolidation of approximately 77 False Claims Act cases filed in various federal district courts by Jack J. Grynberg (called a relator in the parlance of the False Claims Act) on behalf of the United States of America, against more than 330 defendants, including the Utility, and PG&E GTN. The cases were consolidated for pretrial purposes in the District of Wyoming. The current case grows out of prior litigation brought by the same relator in 1995 that was dismissed in 1998.

Under procedures established by the False Claims Act, the United States (acting through the Department of Justice (DOJ)) is given an opportunity to investigate the allegations and to intervene in the case and take over its prosecution if it chooses to do so. In April 1999, the United States DOJ declined to intervene in any of the cases.

The complaints allege that the various defendants (most of which are pipeline companies or their affiliates) incorrectly measured the volume and heat content of natural gas produced from federal or Indian leases. As a result, it is alleged that the defendants underpaid, or caused others to underpay, the royalties that were due to the

United States for the production of natural gas from those leases. The complaints do not seek a specific dollar amount or quantify the royalties claim. The complaints seek unspecified treble damages, civil penalties, and expenses associated with the litigation.

The relator has filed a claim in the Utility's bankruptcy case for $2.48 billion, $2 billion of which is based upon the plaintiff's calculation of penalties against the Utility.

PG&E Corporation and the Utility believe the allegations to be without merit and intend to present a vigorous defense. PG&E Corporation and the Utility believe that the ultimate outcome of the litigation will not have a material adverse effect on their financial condition or results of operations.

Federal Securities Lawsuit

A complaint, Gillam, et al. v. PG&E Corporation, et al., is pending in the U.S. District Court for the Northern District of California. Certain executive officers of PG&E Corporation have also been named as defendants. The first amended complaint, purportedly brought on behalf of all persons who purchased PG&E Corporation common stock or certain shares of the Utility's preferred stock between July 20, 2000, and April 9, 2001, claims that the defendants caused PG&E Corporation's consolidated financial statements for the second and third quarters of 2000 to be materially misleading in violation of federal securities laws as a result of recording as a deferred cost and capitalizing as a regulatory asset the under-collections that resulted when escalating wholesale energy prices caused the Utility to pay far more to purchase electricity than it was permitted to collect from customers. The plaintiff seeks damages in excess of $2.4 billion, punitive damages, interest, injunctive relief, and attorneys' fees.

PG&E Corporation, and other defendants, filed a motion to dismiss based largely on public disclosures by PG&E Corporation, the Utility, and others regarding the under-collections, the risk that they might not be recoverable, the financial consequences of non-recovery, and other information from which analysts and investors could assess for themselves the probability of recovery. On January 14, 2002, the District Court granted the defendants' motion to dismiss the plaintiffs' complaint with leave to amend the complaint. On February 4, 2002, the plaintiffs filed a second amended complaint that, in addition to containing many of the same allegations as appeared in the first amended complaint, contains many of the same allegations that appear in the California Attorney General's complaint discussed below. PG&E Corporation believes the allegations to be without merit and intends to present a vigorous defense. PG&E Corporation believes that the ultimate outcome of the litigation will not have a material adverse effect on PG&E Corporation's financial condition or results of operations.

Order Instituting Investigation (OII) into Holding Company Activities and Related Litigation

On April 3, 2001, the CPUC issued an OII into whether the California investor-owned utilities, including the Utility, have complied with past CPUC decisions, rules, or orders authorizing their holding company formations and/or governing affiliate transactions, as well as applicable statutes. The order states that the CPUC will investigate (1) the utilities' transfer of money to their holding companies since deregulation of the electric industry commenced, including during times when their utility subsidiaries were experiencing financial difficulties, (2) the failure of the holding companies to financially assist the utilities when needed, (3) the transfer by the holding companies of assets to unregulated subsidiaries, and (4) the holding companies' action to "ringfence" their unregulated subsidiaries. The CPUC will also determine whether additional rules, conditions, or changes are needed to adequately protect ratepayers and the public from dangers of abuse stemming from the holding company structure. The CPUC will investigate whether it should modify, change, or add conditions to the holding company decisions, make further changes to the holding company structure, alter the standards under which the CPUC determines whether to authorize the formation of holding companies, otherwise modify the decisions, or recommend statutory changes to the California Legislature. As a result of the investigation, the CPUC may impose remedies, prospective rules, or conditions, as appropriate.

On January 9, 2002, the CPUC issued an interim decision interpreting the "first priority condition" adopted in the CPUC's holding company decision (the condition that the capital requirements of the Utility, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner, be given first priority by the board of directors of the holding company. In the interim decision, the CPUC concluded that the condition, at least under certain circumstances, includes the requirement that each of the holding companies "infuse the utility with all types of capital necessary for the utility to fulfill its obligation to serve." The CPUC also interpreted the first priority condition as prohibiting a holding company from: (1) acquiring assets of its utility subsidiary for inadequate consideration, and (2) acquiring assets of its utility subsidiary at any price, if such acquisition would impair the utility's ability to fulfill its obligation to serve or to operate in a prudent and efficient manner.

In a related decision, the CPUC denied the motions filed by the California utility holding companies to dismiss the holding companies from the pending investigation on the basis that the CPUC lacks jurisdiction over the holding companies. However, in the decision interpreting the first priority condition discussed above, the CPUC separately dismissed PG&E Corporation (but no other utility holding company) as a respondent to the proceeding. In its written decision mailed on January 11, 2002, the CPUC stated that PG&E Corporation was being dismissed so that an appropriate legal forum could decide expeditiously whether adoption of the Utility's proposed plan of reorganization would violate the first priority condition.

On January 10, 2002, the California Attorney General filed a complaint in the San Francisco Superior Court against PG&E Corporation and its directors, as well as against the directors of the Utility alleging PG&E Corporation violated various conditions established by the CPUC in decisions approving the holding company formation among other allegations. The Attorney General also alleges that the December 2000 and January and February 2001 ringfencing transactions by which PG&E Corporation subsidiaries complied with credit rating agency criteria to establish independent credit ratings violated the holding company conditions.

In a press release issued on January 10, 2002, the CPUC expressed support for the Attorney General's complaint, noting that the CPUC's January 9, 2002, decision provided a basis for the Attorney General's allegations and that the CPUC intends to join in a lawsuit against PG&E Corporation based on these issues.

Among other allegations, the Attorney General alleges that, through the Utility's bankruptcy proceedings, PG&E Corporation and the Utility engaged in unlawful, unfair, and fraudulent business practices by seeking to implement the transactions proposed in the proposed plan of reorganization filed in the Utility's bankruptcy proceeding. The complaint also seeks restitution of assets allegedly wrongfully transferred to PG&E Corporation from the Utility. The Bankruptcy Court has original and exclusive jurisdiction of these claims. Therefore, on February 8, 2002, PG&E Corporation filed a notice of removal in the Bankruptcy Court to transfer the Attorney General's complaint to the Bankruptcy Court. On February 15, 2002, a motion to dismiss the lawsuit or in the alternative to stay the suit, was filed.

On February 11, 2002, a complaint entitled, City and County of San Francisco; People of the State of California v. PG&E Corporation, and Does 1-150, was filed in San Francisco Superior Court. The complaint contains some of the same allegations contained in the Attorney General's complaint including allegations of unfair competition. In addition, the complaint alleges causes of action for conversion, claiming that PG&E Corporation "took at least $5.2 billion from PG&E," and unjust enrichment.

Plaintiff seeks injunctive relief, the appointment of a receiver, restitution, disgorgement, the imposition of a constructive trust, civil penalties, and costs of suit.

PG&E Corporation and the Utility believe that they have complied with applicable statutes, CPUC decisions, rules, and orders. Neither the Utility nor PG&E Corporation, however, can predict what the outcome of the CPUC's investigation will be or whether the outcome will have a material adverse effect on their results of operations or financial condition. PG&E Corporation will vigorously respond to and defend the litigation. PG&E Corporation cannot predict whether the outcome of the litigation will have a material adverse effect on its results of operations or financial condition.

William Ahern, et al. v. Pacific Gas and Electric Company

On February 27, 2002, a group of 25 ratepayers filed a complaint against the Utility at the CPUC demanding an immediate reduction of approximately $0.035 per kWh in allegedly excessive electric rates and a refund of alleged recent overcollections in electric revenue since June 1, 2001. The complaint claims that electric rate surcharges adopted in the first quarter of 2001 due to the high cost of wholesale power, surcharges that increased the average electric rate by $0.04 per kWh, became excessive later in 2001. (In January 2001, the CPUC authorized a $0.01 per kWh per KWh increase to pay for energy procurement costs. In March 2001, the CPUC authorized an additional $0.03 per kWh electric rate increase as of March 27, 2001, to pay for energy procurement costs, which the Utility began to collect in June 2001.) The only alleged over-collection amount calculated in the complaint is approximately $400 million during the last quarter of 2001. The complaint has not yet been served on the Utility. The Utility's answer will be due 30 days after the date of service of the complaint.

Recorded Liability for Legal Matters

In accordance with SFAS No. 5, "Accounting for Contingencies," PG&E Corporation makes 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, rulings, advice of legal counsel, and other information and events pertaining to a particular case. The following table reflects the current and prior year's activity to the recorded liability for legal matters for PG&E Corporation and the Utility:

(in millions)	2001	2000
Beginning balance, January 1,	$185	$106
Provisions for liabilities	7	144
Payments	(2)	(45)
Adjustments	19	(20)
Ending balance, December 31,	$209	$185

Note 17: Segment Information

PG&E Corporation has identified three reportable operating segments, which were determined based on similarities in economic characteristics, products and services, types of customers, methods of distributions, the regulatory environment, and how information is reported to PG&E Corporation's key decision makers. The Utility is one reportable operating segment and the other two are part of PG&E NEG. These three reportable operating segments provide products and services and are subject to different forms of regulation or jurisdictions. PG&E Corporation's reportable segments are described below.

Utility

The Utility provides natural gas and electric service to its customers in Northern and Central California.

PG&E NEG

PG&E NEG accounts for its business in two reportable segments. PG&E Energy reflects the integration of PG&E NEG's generation, development, and energy marketing and trading activities. PG&E Pipeline consists principally of the operations of its interstate natural gas transmission pipeline which runs from the Canada/United States border to the California/Oregon border. PG&E GTT was also part of the PG&E Pipeline segment prior to its sale in December 2000. Finally, in 2000, PG&E NEG disposed of its energy services unit, PG&E ES.

Segment information for the years 2001, 2000, and 1999, is as follows:

(in millions)	Utility	PG&E National Energy Group[6] Total PG&E NEG[7]	Integrated Energy & Marketing	Interstate Pipeline Operations	PG&E NEG Eliminations	PG&E Corporation Eliminations & Others[3]	Total
2001							
Operating revenues	$10,450	$12,509	$12,362	$ 153	$ (6)	$ —	$22,959
Intersegment revenues[1]	12	160	67	93	—	(172)	—
Total operating revenues	10,462	12,669	12,429	246	(6)	(172)	22,959
Depreciation, amortization, and decommissioning	896	167	120	42	5	5	1,068
Interest income	123	86	71	7	8	4	213
Interest expense	(974)	(138)	(75)	(37)	(26)	(101)	(1,213)
Income taxes (benefits)[2]	596	57	26	34	(3)	(45)	608
Income (loss) from continuing operations	990	174	102	76	(4)	(74)	1,090
Net income (loss)	990	183	111	76	(4)	(74)	1,099
Capital expenditures	1,343	1,318	1,216	102	—	4	2,665
Total assets at year-end[4]	25,137	10,329	8,922	1,251	156	396	35,862
2000[5]							
Operating revenues	9,623	16,597	15,525	1,066	6	—	26,220
Intersegment revenues[1]	14	182	136	46	—	(196)	—
Total operating revenues	9,637	16,779	15,661	1,112	6	(196)	26,220
Depreciation, amortization, and decommissioning	3,511	143	102	41	—	5	3,659
Interest income	186	80	78	(3)	5	—	266
Interest expense	(619)	(155)	(64)	(90)	(1)	(14)	(788)
Income taxes (benefits)[2]	(2,154)	130	97	37	(4)	(4)	(2,028)
Income (loss) from continuing operations	(3,508)	192	104	78	10	(8)	(3,324)
Net income (loss)	(3,508)	152	104	78	(30)	(8)	(3,364)
Capital expenditures[7]	1,245	1,101	1,086	15	—	—	2,346
Total assets at year-end[4]	21,988	13,967	12,419	1,204	344	197	36,152
1999[5]							
Operating revenues	9,084	11,735	10,402	1,325	8	—	20,819
Intersegment revenues[1]	144	77	30	47	—	(221)	—
Total operating revenues	9,228	11,812	10,432	1,372	8	(221)	20,819
Depreciation, amortization, and decommissioning	1,564	213	97	116	—	3	1,780
Interest income	45	74	66	8	—	(1)	118
Interest expense	(593)	(176)	(76)	(100)	—	(3)	(772)
Income taxes (benefits)[2]	648	(394)	(16)	(375)	(3)	(6)	248
Income (loss) from continuing operations	763	(750)	68	(829)	11	—	13
Net income (loss)	763	(836)	80	(829)	(87)	—	(73)
Capital expenditures[7]	1,181	520	454	49	17	—	1,701
Total assets at year-end[4]	21,470	8,554	5,846	2,377	331	(436)	29,588

(1) Inter-segment revenues are recorded at market prices, which for the Utility and PG&E Pipeline are tariffed rates prescribed by the CPUC and the FERC, respectively.

(2) Income tax expense for the Utility is computed on a stand-alone basis. The balance of the consolidated income tax provision is allocated among PG&E Corporation and the PG&E National Energy Group.

(3) Includes PG&E Corporation, PG&E Ventures, LLC and elimination entries.

(4) Assets of PG&E Corporation are included in the "PG&E Corporation, Eliminations and Others" column exclusive of investment in its subsidiaries.

(5) Segment information for the prior years has been restated for comparative purposes as required by SFAS No. 131.

(6) Income from equity-method investees for 2001, 2000, and 1999, was $79 million, $65 million, and $63 million respectively, for PG&E Gen, and $1 million in 2000, and $0 in 1999, for PG&E GTT.

(7) Capital expenditures and assets of the discontinued operations of PG&E ES are included in the "PG&E Corporation, Eliminations and Others" column. Total assets for PG&E ES at December 31, 2001, 2000, and 1999, were $0, $1 million, and $197 million, respectively. Capital expenditures for 2001, 2000, and 1999, were $0, $0, and $17 million, respectively.

QUARTERLY CONSOLIDATED FINANCIAL DATA (UNAUDITED)

Quarter ended (in millions, except per share amounts)	December 31	September 30	June 30	March 31
2001				
PG&E Corporation				
Operating revenues	$ 4,978	$6,298	$5,010	$ 6,673
Operating income (loss)	1,077	1,552	1,447	(1,340)
Income (Loss) from continuing operations	520	771	750	(951)
Net income (loss)	529	771	750	(951)
Earnings (Loss) per common share, basic	1.46	2.12	2.07	(2.62)
Earnings (Loss) per common share, diluted	1.45	2.12	2.07	(2.62)
Common stock price per share				
High	20.10	17.45	12.54	20.94
Low	14.96	11.66	6.50	8.38
Utility				
Operating revenues	$ 2,654	$2,937	$2,309	$ 2,562
Operating income (loss)	1,134	1,428	1,336	(1,420)
Net income (loss)	563	744	702	(994)
Income (Loss) available for (allocated to) common stock	557	737	696	(1,000)
2000				
PG&E Corporation				
Operating revenues	$ 8,079	$7,502	$5,637	$ 5,002
Operating income (loss)[1][2]	(6,734)	629	622	676
Income (Loss) from continuing operations	(4,096)	244	248	280
Net income (loss) [1] [2]	(4,117)	225	248	280
Earnings (Loss) per common share from continuing operations, basic	(11.28)	0.67	0.69	0.78
Earnings (Loss) per common share from continuing operations, diluted	(11.28)	0.67	0.68	0.77
Dividends declared per common share	0.30	0.30	0.30	0.30
Common stock price per share				
High	29.50	31.81	27.75	23.13
Low	17.00	22.31	20.63	19.69
Utility				
Operating revenues	$ 2,600	$2,523	$2,296	$ 2,218
Operating income (loss)	(6,856)	533	552	570
Net income (loss)	(4,156)	217	222	234
Income (Loss) available for (allocated to) common stock	(4,163)	211	216	228

(1) In the third quarter of 2000, an estimated loss of $19 million ($0.05 per share), net of income taxes of $13 million, was recorded related to the disposal of PG&E ES. In the fourth quarter of 2000, an additional estimated loss of $21 million ($0.06 per share), net of income taxes of $23 million, also was recorded related to the disposal of PG&E ES.

(2) In the fourth quarter of 2000, the Utility recorded a charge to earnings for the write-off of regulatory assets representing transition costs and under-collected purchased power costs. The write-off was $6.9 billion ($4.1 billion after tax) and reflected the fact that, based upon the current status of the California energy crisis, the Utility could no longer conclude that the regulatory assets were probable of recovery through regulated rates. Also, in the fourth quarter of 2000, the Utility recognized a $140 million ($83 million, after tax) provision for an increase in legal reserves.

INDEPENDENT AUDITORS' REPORT

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 and Pacific Gas and Electric Company (a Debtor-in-Possession) and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of operations, cash flows and common stockholders' equity of PG&E Corporation and the related statements of consolidated operations, cash flows and stockholders' equity of Pacific Gas and Electric Company (a Debtor-in-Possession) for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the management of PG&E Corporation and of Pacific Gas and Electric Company. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such 2001 and 2000 consolidated financial statements present fairly, in all material respects, the consolidated financial position of PG&E Corporation and Pacific Gas and Electric Company as of December 31, 2001 and 2000, and the results of their consolidated operations and cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 of the Notes to the Consolidated Financial Statements, PG&E Corporation and Pacific Gas and Electric Company adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by Statement of Financial Accounting Standards No. 138, "Accounting for Certain Derivatives and Hedging Activities," effective January 1, 2001, and interpretations issued by the Derivatives Implementation Group of the Financial Accounting Standards Board during 2001, and in 1999, PG&E Corporation changed its method of accounting for major maintenance and overhauls.

The accompanying consolidated financial statements have been prepared on a going concern basis of accounting. As discussed in Notes 2 and 3 of the Notes to the Consolidated Financial Statements, Pacific Gas and Electric Company, a subsidiary of PG&E Corporation, has incurred power purchase costs substantially in excess of amounts charged to customers in rates. On April 6, 2001, Pacific Gas and Electric Company sought protection from its creditors by filing a voluntary petition under provisions of Chapter 11 of the U.S. Bankruptcy Code. These matters raise substantial doubt about Pacific Gas and Electric Company's ability to continue as a going concern. Managements' plans in regard to these matters are also described in Notes 2 and 3 of the Notes to the Consolidated Financial Statements. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

DELOITTE & TOUCHE LLP
San Francisco, California
March 1, 2002

RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

PG&E Corporation and Pacific Gas and Electric Company (the Utility) management are responsible for the integrity of the accompanying consolidated financial statements. The financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America. Management considers materiality and uses its best judgment to ensure that such statements reflect fairly the financial position, results of operations, and cash flows of PG&E Corporation and the Utility.

PG&E Corporation and the Utility maintain systems of internal controls supported by formal policies and procedures, which are communicated throughout PG&E Corporation and the Utility. These controls are adequate to provide reasonable assurance that assets are safeguarded from material loss or unauthorized use and that necessary records are produced for the preparation of consolidated financial statements. There are limits inherent in all systems of internal controls, based on recognition that the costs of such systems should not exceed the benefits to be derived. PG&E Corporation and the Utility believe that their systems of internal control provide this appropriate balance. PG&E Corporation management also maintains a staff of internal auditors who evaluate the adequacy of, and assess the adherence to, these controls, policies, and procedures for all of PG&E Corporation, including the Utility.

Both PG&E Corporation's and the Utility's consolidated financial statements included herein have been audited by Deloitte & Touche LLP, PG&E Corporation's independent auditors. The audit includes consideration of internal accounting controls and performance of tests necessary to support an opinion. The auditors' report contains an independent informed judgment as to the fairness, in all material respects, of reported results of operations and financial position.

The Audit Committee of the Board of Directors of PG&E Corporation meets regularly with management, internal auditors, and Deloitte & Touche LLP, jointly and separately, to review internal accounting controls and auditing and financial reporting matters. The internal auditors and Deloitte & Touche LLP have free access to the Audit Committee, which consists of five outside directors. The Audit Committee has reviewed the financial data contained in this report.

PG&E Corporation and the Utility are committed to full compliance with all laws and regulations and to conducting business in accordance with high standards of ethical conduct. Management has taken the steps necessary to ensure that all employees and other agents understand and support this commitment. Guidance for corporate compliance and ethics is provided by an officers' Ethics Committee and by a Legal Compliance and Business Ethics organization. PG&E Corporation and the Utility believe that these efforts provide reasonable assurance that each of their operations is conducted in conformity with applicable laws and with their commitment to ethical conduct.

Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company[1]

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

David A. Coulter
Vice Chairman, J.P. Morgan Chase & Co.

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

William S. Davila
President Emeritus, The Vons Companies, Inc. (retail grocery)

Robert D. Glynn, Jr.
Chairman of the Board, Chief Executive Officer, and President, PG&E Corporation and Chairman of the Board, Pacific Gas and Electric Company

David M. Lawrence, MD
Chairman and Chief Executive Officer, Kaiser Foundation Health Plan, Inc. and Kaiser Foundation Hospitals

Mary S. Metz
President, S. H. Cowell Foundation

Carl E. Reichardt
Vice Chairman, Ford Motor Company, and Chairman of the Board and Chief Executive Officer, Retired, Wells Fargo & Company and Wells Fargo Bank, N.A.

Gordon R. Smith[1]
President and Chief Executive Officer, Pacific Gas and Electric Company

Barry Lawson Williams
President, Williams Pacific Ventures, Inc. (business consulting and mediation)

(1) The composition of the Boards of Directors is the same, except that Gordon R. Smith is a director of the Pacific Gas and Electric Company Board of Directors only.

Permanent Committees of PG&E Corporation and Pacific Gas and Electric Company[1]

Executive Committees

Within limits, may exercise powers and perform duties of the Boards.

Robert D. Glynn, Jr., Chair
C. Lee Cox
Mary S. Metz
Carl E. Reichardt
Gordon R. Smith[1]
Barry Lawson Williams

Audit Committees

Review financial statements and internal audit and control procedures with independent public accountants.

C. Lee Cox, Chair
David R. Andrews
William S. Davila
Mary S. Metz
Barry Lawson Williams

Finance Committee

Reviews long-term financial and capital investment policies and objectives, and actions required to achieve those objectives.

Barry Lawson Williams, Chair
David R. Andrews
David A. Coulter
Carl E. Reichardt

Nominating and Compensation Committee

Recommends candidates for nomination as directors, recommends compensation and employee benefit policies and practices, and reviews planning for executive development and succession.

Carl E. Reichardt, Chair
David A. Coulter
C. Lee Cox
David M. Lawrence, MD

Public Policy Committee

Reviews public policy issues which could significantly affect customers, shareholders, employees, or the communities served, and recommends plans and programs to address such issues.

Mary S. Metz, Chair
William S. Davila
David M. Lawrence, MD

(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 Gordon R. Smith is a member of the Pacific Gas and Electric Company Executive Committee only.

Officers

PG&E Corporation

Robert D. Glynn, Jr.
Chairman of the Board, Chief Executive Officer, and President

Thomas G. Boren
Executive Vice President

Peter A. Darbee
Senior Vice President and Chief Financial Officer

P. Chrisman Iribe
Senior Vice President

Christopher P. Johns
Senior Vice President and Controller

Thomas B. King
Senior Vice President

L. E. Maddox
Senior Vice President

Daniel D. Richard, Jr.
Senior Vice President, Public Affairs

Gordon R. Smith
Senior Vice President

G. Brent Stanley
Senior Vice President, Human Resources

Bruce R. Worthington
Senior Vice President and General Counsel

Leroy T. Barnes, Jr.
Vice President and Treasurer

Leslie H. Everett
Vice President and Assistant to the Chairman

David S. Gee
Vice President, Strategic Planning

DeAnn Hapner
Vice President, Special Projects

Steven L. Kline
Vice President, Federal Governmental and Regulatory Relations

Laura L. Langer
Vice President, Risk Management

Greg S. Pruett
Vice President, Corporate Communications

Gabriel B. Togneri
Vice President, Investor Relations

PG&E National Energy Group

Thomas G. Boren
President and Chief Executive Officer

P. Chrisman Iribe
President and Chief Operating Officer, East Region

Thomas B. King
President and Chief Operating Officer, West Region

L. E. Maddox
President and Chief Operating Officer, Trading

Pacific Gas and Electric Company

Robert D. Glynn, Jr.
Chairman of the Board

Gordon R. Smith
President and Chief Executive Officer

Kent M. Harvey
Senior Vice President, Chief Financial Officer, and Treasurer

Roger J. Peters
Senior Vice President and General Counsel

James K. Randolph
Senior Vice President and Chief of Utility Operations

Daniel D. Richard, Jr.
Senior Vice President, Public Affairs

Gregory M. Rueger
Senior Vice President, Generation and Chief Nuclear Officer

Shareholder Information

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

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 Mellon Investor Services:

Mellon Investor Services
P.O. Box 3310 (Securities Transfer)
P.O. Box 3315 (General Correspondence)
P.O. Box 3316 (Change of Address)
P.O. Box 3317 (Lost Certificate Replacement)
P.O. Box 3338 (Dividend Reinvestment)
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 write or call the Corporate Secretary's Office:

Corporate Secretary
Linda Y.H. Cheng
PG&E Corporation
P.O. Box 193722
San Francisco, CA 94119-3722
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
P.O. Box 193722
San Francisco, CA 94119-3722
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 11 issues of preferred stock and one preferred security, all of which are listed on the American and Pacific stock exchanges.

Issue	Newspaper Symbol[(1)]
First Preferred, Cumulative, Par Value $25 Per Share	
Redeemable:	
7.04%	PacGE pfU
6.57%	PacGE pfY
6.30%	PacGE pfZ
5.00%	PacGE pfD
5.00% Series A	PacGE pfE
4.80%	PacGE pfG
4.50%	PacGE pfH
4.36%	PacGE pfI
Non-Redeemable:	
6.00%	PacGE pfA
5.50%	PacGE pfB
5.00%	PacGE pfC
Cumulative Quarterly Income Preferred Securities:	
7.90% Series A	PG&E Cap pfA

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.

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 17, 2002
Time: 10:00 a.m.

Location: Masonic Auditorium,
1111 California Street
San Francisco, 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 13, 2002, to all shareholders of record as of February 19, 2002.

10-K Report
If you would like a copy of the 2001 Form 10-K Report to the Securities and Exchange Commission, please contact the Office of the Corporate Secretary, or visit our websites, www.pgecorp.com and www.pge.com.

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